A. ACRONYMS

These acronyms clarify the terms and concepts used throughout this Integrated Resource Plan.

ACE	Affordable Clean Energy
ACP	Alternate Compliance Payments
AGC	Automatic Generator Control
BA	Balancing Authority
BCIS	Blockchain Interruptible Service
BES	Bulk Electric System
BESS	Battery Energy Storage System
Btu	British Thermal Unit
CAA	Consolidated Appropriations Act of 2016
CAISO	California Independent System Operator
CCUS	Carbon Capture, Utilization, And Storage
CDD	Cooling Degree Days
CDH	Cooling Degree Hours
CLEAN	Climate Leadership and Environmental Action for our Nation
CO_2	Carbon Dioxide
CPCN	Certificates of Public Convenience and Necessity
CPGS	Cheyenne Prairie Generating Station
CRISP	Cybersecurity Risk Information Sharing Program
CT	Combustion Turbine
DOE	Department of Energy
DR	Demand Response
DSIP	Distribution System Integrity Program
DSM	Demand-Side Management
E3	Energy + Environmental Economics
EEI	Edison Electric Institute
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERO	Electric Reliability Organization
EV	Electric vehicle
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
GDPM	Generation Dispatch and Power Marketing
GHG	Greenhouse Gas
HAPG	Hitachi ABB Power Grids
HDD	Heating Degree Days
HDH	Heating Degree Hours
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning
ICS	Corporate and Industrial Control System
IEEE	Institute of Electrical and Electronics Engineers
IRP	Integrated Resource Plan

ISO	Independent System Operator
ITC	Investment Tax Credit
kW	Kilowatt
kWh	Kilowatt Hours
LiDAR	Light Detection and Ranging
LNG	Liquefied Natural Gas
LPCS	Large Power Contract Service
LTP	Local Transmission Plan
MAPP	Mid-Continent Area Power Pool
MDU	Montana-Dakota Utilities
MDWQ	Maximum Daily Withdrawal Quantity
MEAN	Municipal Energy Agency of Nebraska
MMBtu	One Million Btu
MW	Megawatt
MWh	Megawatt Hour
NDC	Nationally Determined Contribution
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NO_X	Nitrogen Oxide
NWPP	Northwest Power Pool
O&M	Operations And Maintenance
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OSHA	Occupational Safety and Health Administration
PATH	Protecting Americans from Tax Hikes Act of 2015
PLM	Project Lifecycle Management
PMI	Project Management Institute
PPA	Power Purchase Agreement
PRPA	Platte River Power Authority
PSCO	Public Service Company of Colorado
PTC	Production Tax Credit
PV	Photovoltaic
PVRR	Present Value Revenue Requirement
RAC	Reliability Assessment Committee
RTO	Regional Transmission Organization
SCALE	Storing CO_2 and Lowering Emissions
SCR	Selective Catalytic Reactors
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
SSCGP	Southern Star Central Gas Pipeline
T&ES	Transmission and Engineering Services
TCPC	Transmission Coordination and Planning Committee
TSA	Transmission Service Agreement
UNFCCC	United Nations Framework Convention on Climate Change
VER	Variable Energy Resource
WACM	Western Area Power Administration, Colorado Missouri
WAPA	Western Area Power Administration
WAPA-LAP	WAPA Loveland Area Project
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WJDA	Western Joint Dispatch Agreement

B. WECC CONTINGENCY RESERVE SPECIFICATIONS

The WECC Standard BAL-002-WECC-2a specification details the planning standard for specifying the quantity and types of contingency reserves required to ensure reliability under normal and abnormal conditions.

On January 24, 2017, FERC approved an interpretation to BAL-002-WECC-2 that clarified the types of resources that can be used to satisfy contingency reserve. The standard's designation was changed to BAL-002-WECC-2a.

WECC STANDARD BAL-002-WECC-2A—CONTINGENCY RESERVE

A. Introduction

1. **Title:** **Contingency Reserve**

2. **Number:** BAL-002-WECC-2a

3. **Purpose:** To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions.

4. **Applicability:**

   4.1 Balancing Authority

   4.1.1. The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

   4.2 Reserve Sharing Group

   4.2.1. The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the source Reserve Sharing Group.

   4.2.2. The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group.

5. **Effective Date:** See Implementation Plan.

B. Requirements and Measures

R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is: [*Violation Risk Factor: High] [Time Horizon: Real-time operations]*

1.1 The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

1.2 Comprised of any combination of the reserve types specified below:

- Operating Reserve – Spinning

- Operating Reserve - Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve – Supplemental
- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service
- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.

1.3 Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).

1.4 An amount of capacity from a resource that is deployable within ten minutes.

M1. Each Balancing Authority and each Reserve Sharing Group will have documentation demonstrating its Contingency Reserve was maintained, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Part 1.1

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates its Contingency Reserve was maintained in accordance with the amounts identified in Requirement R1, Part 1.1, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Attachment A is a practical illustration showing how the generation amount may be calculated under Requirement R1.

- Where Dynamic Schedules are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1 may include, but is not limited to, documentation showing a reciprocal acknowledgement as to which entity is carrying the reserves. This transfer may be all or some portion of the physical generator and is not limited to the entire physical capability of the generator.

- Where Pseudo-Ties are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1, may include, but is not limited to, documentation accounting for the transfers included in the Pseudo-Ties.

Part 1.2

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.2. Evidence may include, but is not limited to, documentation that reserves were comprised of the types listed in Requirement R1, Part 1.2 for purposes of meeting the Contingency Reserve obligation of Requirement R1. Additionally, for purposes of the last bullet of Requirement R1, Part 1.2, evidence of compliance may include, but is not limited to, documentation that the reliability coordinator had issued an energy emergency alert, indicating that firm Load interruption was imminent or was in progress.

Part 1.3

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.3. Evidence of compliance with Requirement R1, Part 1.3 may include, but is not limited to, documentation that Contingency Reserve amounts are based upon load and generating data averaged over each Clock Hour and excludes Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464.

Part 1.4

Evidence of compliance with Requirement R1, Part 1.4 may include, but is not limited to, documentation that the reserves maintained to comply with Requirement R1, Part 1.4 are fully deployable within ten minutes.

R2. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning that meets both of the following reserve characteristics. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

2.1 Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;

2.2 Reserve that is capable of fully responding within ten minutes.

M2. Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates it maintained at least half of the Contingency Reserve identified in Requirement R1 as Operating Reserve – Spinning, averaged over each Clock Hour, that met both of the reserve characteristics identified in Requirement R2, Part 2.1 and Requirement R2, Part 2.2.

R3. Each Sink Balancing Authority and each sink Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M3. Each Sink Balancing Authority and each sink Reserve Sharing Group will have dated documentation demonstrating it maintained an amount of Operating Reserve, in addition to the Contingency Reserve identified in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, for the entire period of the transaction, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, in accordance with Requirement 3.

R4. Each Source Balancing Authority and each source Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source Balancing Authority or source Reserve Sharing Group. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M4. Each Source Balancing Authority and each source Reserve Sharing Group will have dated documentation that demonstrates it maintained an amount of additional Operating Reserves identified in Requirement R1, greater than or equal to the amount and type of that identified in Requirement 4, for the entire period of the transaction.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2 Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3 Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority and each Reserve Sharing Group shall keep evidence for Requirement R1 through R4 for three years plus calendar current.

1.4. Additional Compliance Information

1.4.1. This Standard shall apply to each Balancing Authority and each Reserve Sharing Group that has registered with WECC as provided in Part 1.4.2 of Section C.

Each Balancing Authority identified in the registration with WECC as provided in Part 1.4.2 of Section C shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

1.4.2. A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC: 1) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, 2) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and 3) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

1.4.3. If an agent properly designated in accordance with Part 1.4.2 of Section C identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance: 1) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, 2) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection 1) of this Part 1.4.3 of Section C, and 3) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection 1) of this Part 1.4.3 of Section C (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

1.4.4. If an agent properly designated in accordance with Part 1.4.2 of Section C fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

1.4.5. Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Part 1.4.2 of Section C shall be subject to this Standard on an individual basis.

Table of Compliance Elements

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.
R2	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 100% but greater than or equal to 90% of	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 90% but greater than or	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 80% but greater than or	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 70% of the required

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	equal to 80% of the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	equal to 70% of the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.
R3	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R3.
R4	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operating Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R4.	Operating Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R4.	Operating Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R4.	Operating Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R4.

D. Regional Variances
None.

E. Interpretations

Interpretation Requested

Arizona Public Service (APS) sought clarification that for purposes of BAL-002-WECC-2, Requirement R2, APS and other Balancing Authorities and/or Reserve Sharing Groups can include “technologies, such as batteries, both contemplated and not yet contemplated…as potential resources [to meet the Operating Reserve – Spinning requirement of BAL-002-WECC-2, Requirement R2] – so long as the…resource can meet the response characteristics described in the standard.”

A standards interpretation team comprised of members of the original BAL drafting team concluded that APS’ understanding was correct.

“[N]on-traditional resources, including electric storage facilities, may qualify as “Operating Reserve – Spinning” so long as they meet the technical and performance requirements in Requirement R2 (i.e., that the resources must be immediately and automatically responsive to frequency deviations through the action of a control system and capable of fully responding within ten minutes).[1]

[1] FERC Order 789, P47. July 18, 2013.

See also FERC Order 740, Section E, Demand-Side Management as a Resource, at P 50:
“The Commission clarified that the purpose of this directive was to ensure comparable treatment of demand-side management with conventional generation or any other technology and to allow demand-side management

In Order 789, Paragraph 48, the Federal Energy Regulatory Commission (Commission) responded to the California Independent System Operator that:

> **Commission Determination**
>
> 48. The Commission determines that non-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Our determination is supported by the standard drafting team's response to a comment during the standard drafting process where the standard drafting team stated that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard …The language does not preclude any specific technology; rather, the language delineates how that technology must [] respond."[2] We also note that non-traditional resources could contribute to contingency reserve under the regional Reliability Standard if they are resources, "other than generation or load, that can provide energy or reduce energy consumption."

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to be considered as a resource for contingency reserves on this basis without requiring the use of any particular contingency reserve option."

[2] "Fn 44 Petition, Exhibit C at 20."

F. Associated Documents

None.

Attachment A

Attachment A is illustrative only; it is not a requirement. Requirement R1 calls for an amount of Contingency Reserve to be maintained, predicated on an amount of generation and load required in Requirement R1, Part 1.1., specifically:

> "**1.1** The greater of either:
>
> - The amount of Contingency Reserve equal to the loss of the most severe single contingency;
> - The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

Attachment A illustrates one possible way to account for and calculate the amount of generation upon which the Contingency Reserve amount is predicated.

Below is a practical illustration showing how the generation amount may be calculated under Requirement R1 for Balancing Authorities (BA) and Reserve Sharing Groups (RSG).

BA1 / RSG 1	**Generation**	**Part of Generator**
Generator 1	300 MWs online	Yes
Generator 2	200 MWs online	Yes
Generator 3 (Pseudo-Tied out to BA2)	100 MWs online	No
Generator 4 QF (has backup contract)	10 MWs online	No
Generator 5 QF in EMS	10 MWs online	Yes
Generator 6	0 MWs online	Yes
Dynamic Schedule to BA2 from BA1[3]	(50 MWs)	
Generation	620 MWs	(The sum of gen 1-6)
BA generation (EMS)	510 MWs	(The sum of gen 1, 2, and 5)
Generation to use Under BAL-002-WECC-1	460 MWs**	(The sum of gen 1, 2 and 5 minus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would maintain reserves based on 510 MWs Generation.

BA2 / RSG2	**Generation**	**Part of Generator**
Generator 11	100 MWs	Yes
Generator 12	100 MWs	Yes
Generator 3 (Pseudo-Tied in from BA1)	100 MWs	Yes

[3] Note: This Dynamic Schedule is not the same as the Generator 3 Pseudo-Tie.

<u>Dynamic Schedule from BA1 to BA2</u>	<u>50 MWs</u>	<u>Yes</u>
Generation	300 MWs	(The sum of gen 11, 12 and 3.)
BA generation (EMS)	300 MWs	(The sum of gen 11, 12 and 3)
Generation to use Under BAL-002-WECC-1	350 MWs**	(The sum of gen 11, 12 and 3 plus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would have to maintain reserves based on 510MWs Generation and BA2 would determine its generation to be 300 MWs.

Guideline and Technical Basis

A Guidance Document addressing implementation of this standard has been filed with this standard.

Version History

Version	Date	Action	Change Tracking
1	October 29, 2008	Adopted by NERC Board of Trustees	
1	October 21, 2010	Order issued remanding BAL-002-WECC-1	
2	November 7, 2012	Adopted by NERC Board of Trustees	
2	November 21, 2013	FERC Order issued approving BAL-002-WECC-2. (Order becomes effective 1/28/14.)	
2a	December 1, 2015	Approved by WECC Board of Directors	Clarified resources available for use in Requirement R2
2a	November 2, 2016	Approved by NERC Board of Trustees	
2a	January 24, 2017	FERC letter Order approving BAL-002-WECC-2a. Docket No. RD17-3-000	

C. LOAD FORECAST DATA

This appendix contains the load forecast schedules for Cheyenne Light and Black Hills Power that were used in the IRP modeling. Cheyenne Light Schedule C-3 and the Black Hills Power Schedule C-3 are both confidential.

CHEYENNE LIGHT LOAD FORECAST DATA

Schedule C-1. Cheyenne Light: Monthly Historic Demand (MW)

Cheyenne Light | **Confidential Appendix C**
Cheyenne Light: Monthly Historic Demand (MW) | **Schedule C-1**

Year	Month	System Demand less Large Volume Customer (MW)
2008	1	155
2008	2	150
2008	3	142
2008	4	141
2008	5	142
2008	6	159
2008	7	173
2008	8	174
2008	9	141
2008	10	143
2008	11	153
2008	12	176
2009	1	165
2009	2	156
2009	3	152
2009	4	144
2009	5	145
2009	6	158
2009	7	169
2009	8	160
2009	9	153
2009	10	150
2009	11	154
2009	12	171
2010	1	170
2010	2	159
2010	3	152
2010	4	141
2010	5	145
2010	6	164
2010	7	176
2010	8	158
2010	9	154
2010	10	145
2010	11	164
2010	12	163
2011	1	173
2011	2	175
2011	3	159
2011	4	142
2011	5	142
2011	6	163

2011	7	181
2011	8	172
2011	9	168
2011	10	154
2011	11	156
2011	12	175
2012	1	166
2012	2	160
2012	3	155
2012	4	143
2012	5	146
2012	6	184
2012	7	187
2012	8	182
2012	9	162
2012	10	153
2012	11	164
2012	12	174
2013	1	173
2013	2	165
2013	3	164
2013	4	163
2013	5	155
2013	6	172
2013	7	185
2013	8	182
2013	9	177
2013	10	146
2013	11	161
2013	12	174
2014	1	176
2014	2	177
2014	3	165
2014	4	153
2014	5	160
2014	6	158
2014	7	186
2014	8	179
2014	9	167
2014	10	149
2014	11	170
2014	12	182
2015	1	173
2015	2	172
2015	3	160
2015	4	155
2015	5	148
2015	6	178

2015	7	187
2015	8	185
2015	9	181
2015	10	153
2015	11	167
2015	12	171
2016	1	166
2016	2	168
2016	3	154
2016	4	150
2016	5	149
2016	6	188
2016	7	193
2016	8	188
2016	9	170
2016	10	154
2016	11	173
2016	12	181
2017	1	181
2017	2	169
2017	3	166
2017	4	153
2017	5	152
2017	6	181
2017	7	197
2017	8	184
2017	9	171
2017	10	154
2017	11	160
2017	12	176
2018	1	173
2018	2	174
2018	3	164
2018	4	153
2018	5	156
2018	6	190
2018	7	197
2018	8	175
2018	9	172
2018	10	156
2018	11	162
2018	12	175
2019	1	171
2019	2	173
2019	3	171
2019	4	158
2019	5	155
2019	6	176

2019	7	198
2019	8	190
2019	9	189
2019	10	153
2019	11	165
2019	12	171

** Shown are the monthly aggregations that are from the hourly data that was used in the econor*

Schedule C-2. Cheyenne Light: Monthly Historic Class Sales Data

Cheyenne Light | **Confidential Appendix C**

Cheyenne Light: Monthly Historic Class Sales Data | **Schedule C-2**

Year	Month	Residential (MWh)	Commercial No Demand (MWh)	Commerical General Service Secondary (MWh)	Commerical General Service Primary (MWh)	Industrial (MWh)
2005	1					
2005	2	22,931.27				10,792.33
2005	3	21,341.50				11,536.58
2005	4	20,102.97				11,014.30
2005	5	19,045.92				10,949.71
2005	6	20,307.14				11,229.48
2005	7	20,812.58				11,959.23
2005	8	21,712.45				11,531.22
2005	9	19,794.65				11,787.23
2005	10	17,730.17				11,268.71
2005	11	19,593.98				11,146.95
2005	12	24,349.75				11,812.39
2006	1	25,408.14				11,755.56
2006	2	22,671.86				10,524.96
2006	3	23,098.55				11,224.79
2006	4	18,677.83				10,785.81
2006	5	18,705.42				11,438.25
2006	6	19,707.63				10,427.61
2006	7	20,216.32				11,062.93
2006	8	22,178.40				11,869.73
2006	9	17,310.89				7,206.14
2006	10	18,298.96				10,071.17
2006	11	20,793.85				11,433.55
2006	12	22,820.05				11,661.18
2007	1	26,460.75				11,259.09
2007	2	22,578.51				10,011.23
2007	3	21,615.71				13,153.38
2007	4	19,214.97				11,390.34
2007	5	18,712.12				12,236.39
2007	6	18,021.15				11,400.90
2007	7	21,287.93				11,962.25
2007	8	22,644.26				11,979.02
2007	9	18,937.82				11,756.97
2007	10	18,302.78				12,353.78
2007	11	19,640.06				11,759.87
2007	12	23,896.53				12,089.94
2008	1	28,405.78				11,043.52
2008	2	23,440.12				11,108.61
2008	3	23,496.26				11,594.63
2008	4	20,486.68				10,094.40
2008	5	18,627.63				12,902.66

2008	6	18,209.90				13,025.96
2008	7	21,548.12				14,241.21
2008	8	21,595.84				14,385.55
2008	9	17,841.88				10,171.02
2008	10	18,447.96				11,098.97
2008	11	19,563.54				9,644.24
2008	12	23,681.10				14,868.30
2009	1	25,384.13				14,975.02
2009	2	23,757.56				13,380.32
2009	3	21,983.88				14,466.92
2009	4	21,934.34				14,253.67
2009	5	18,963.61				14,698.44
2009	6	18,201.65				14,473.10
2009	7	19,813.55				15,299.90
2009	8	20,329.53				15,327.87
2009	9	19,239.51				14,819.19
2009	10	19,132.90				14,334.79
2009	11	21,981.00				14,271.45
2009	12	24,409.59				14,491.51
2010	1	27,397.62		29,664.80	15,789.65	14,491.51
2010	2	23,882.09		28,671.39	15,905.27	13,420.82
2010	3	23,546.57		27,047.25	15,316.48	12,902.97
2010	4	21,373.00		27,948.52	16,014.65	14,434.88
2010	5	19,068.67		27,869.17	15,526.45	14,049.95
2010	6	18,711.64		28,727.49	15,859.20	14,906.84
2010	7	20,399.29		31,046.01	17,217.46	14,714.40
2010	8	21,281.09		32,586.19	17,330.42	14,083.37
2010	9	20,005.70		32,380.05	12,871.89	8,953.32
2010	10	18,030.45		30,198.16	16,009.40	9,903.94
2010	11	19,291.01		28,143.65	17,589.71	14,629.32
2010	12	25,812.36		30,499.42	17,174.12	14,278.13
2011	1	27,397.20		30,742.97	16,212.44	14,866.42
2011	2	24,776.37		28,418.25	16,435.05	14,384.48
2011	3	23,678.95		29,565.76	16,056.90	13,263.67
2011	4	21,263.91		28,726.69	16,383.22	13,114.96
2011	5	19,346.81		26,877.78	14,267.25	14,375.31
2011	6	19,162.84		29,132.16	16,822.68	13,901.29
2011	7	20,864.68		29,999.54	17,413.70	14,365.30
2011	8	22,883.34		32,349.69	17,645.28	15,300.19
2011	9	21,089.03		30,763.91	16,568.67	14,694.70
2011	10	18,327.76		28,374.53	18,094.14	14,862.50
2011	11	21,711.70		29,236.01	17,799.11	14,930.59
2011	12	24,647.99		29,291.54	17,781.47	14,555.24
2012	1	25,551.87		29,314.08	16,891.00	15,027.73
2012	2	23,891.79		28,423.98	17,409.05	15,525.27
2012	3	23,704.91		29,247.57	17,457.49	14,182.31
2012	4	19,649.96		30,387.36	18,374.13	15,066.62
2012	5	18,629.75		29,318.82	18,213.06	14,264.56

2012	6	18,305.36		29,532.48	18,473.11	14,616.35
2012	7	23,668.26		32,912.75	17,806.65	15,274.31
2012	8	24,737.90		32,729.02	9,748.89	25,466.06
2012	9	22,311.70		32,375.55	9,939.83	24,046.67
2012	10	18,628.28		29,518.14	9,166.87	22,969.76
2012	11	21,120.36		29,331.60	9,273.33	23,370.60
2012	12	23,428.23		29,700.29	9,654.28	24,310.29
2013	1	26,729.52		30,927.86	8,914.56	25,440.56
2013	2	23,855.22		29,494.27	8,523.59	23,918.01
2013	3	24,371.96		30,682.35	9,017.38	21,045.38
2013	4	22,374.64		30,015.35	8,856.96	24,988.44
2013	5	19,895.56		29,684.25	9,224.65	24,373.06
2013	6	19,201.64		30,794.82	9,866.94	25,290.77
2013	7	22,872.22		32,875.74	9,438.78	16,052.53
2013	8	20,908.93		31,271.03	9,477.69	25,083.38
2013	9	22,088.59		32,548.74	9,972.80	25,926.25
2013	10	19,579.39		29,852.36	9,211.10	23,306.00
2013	11	20,699.47		28,358.82	7,446.11	20,990.48
2013	12	26,719.17		33,113.53	9,810.47	22,700.08
2014	1	27,581.42	4,642.07	32,912.70	11,166.23	24,977.59
2014	2	24,640.90	4,349.87	29,639.20	7,889.27	24,326.07
2014	3	23,095.49	4,158.54	29,680.82	10,497.81	21,406.43
2014	4	21,277.75	3,945.35	29,890.32	9,525.16	23,640.31
2014	5	18,872.41	3,572.19	29,035.95	9,692.26	24,003.84
2014	6	17,705.89	3,412.16	29,436.41	9,536.90	24,501.15
2014	7	20,153.04	3,812.85	31,320.57	9,561.74	21,996.65
2014	8	22,604.18	4,193.86	33,605.25	10,260.02	23,099.89
2014	9	19,524.14	3,736.86	30,774.35	9,920.72	25,476.94
2014	10	18,036.03	3,593.49	28,909.15	9,702.67	23,628.70
2014	11	19,520.07	3,733.23	27,536.19	9,338.98	26,016.85
2014	12	26,078.81	4,721.38	31,978.90	10,670.93	19,557.91
2015	1	26,609.43	4,820.01	33,052.72	10,843.16	25,886.75
2015	2	23,371.33	4,354.03	29,058.57	9,916.11	25,256.68
2015	3	22,953.11	4,355.66	30,861.56	10,579.70	23,429.57
2015	4	18,881.84	3,799.41	28,508.94	9,739.08	23,177.14
2015	5	18,796.68	3,671.70	28,546.45	10,237.15	23,949.66
2015	6	19,075.65	3,779.53	30,080.00	10,248.07	22,668.14
2015	7	21,043.00	3,981.27	31,743.81	10,160.28	24,309.07
2015	8	21,774.42	4,158.78	31,600.90	10,937.69	25,688.94
2015	9	20,789.95	3,964.84	30,928.25	11,242.28	25,882.68
2015	10	18,330.86	3,732.41	29,202.30	11,462.66	25,024.74
2015	11	18,770.72	3,636.56	27,906.83	9,814.41	25,846.92
2015	12	25,556.38	4,613.92	31,236.83	11,640.13	24,483.48
2016	1	26,307.78	4,667.05	29,537.70	10,157.56	23,246.04
2016	2	23,420.38	4,189.24	28,622.18	10,863.85	23,764.74
2016	3	21,860.07	4,216.41	29,411.81	11,090.37	21,817.02
2016	4	21,911.54	4,115.83	30,027.86	11,172.18	25,520.28
2016	5	19,860.64	3,757.82	28,115.96	11,023.35	21,872.40

2016	6	19,431.41	3,777.48	30,277.72	11,351.72	22,026.60
2016	7	22,728.58	4,065.39	31,025.00	9,834.99	23,021.04
2016	8	23,621.35	4,415.78	32,608.61	12,744.35	24,471.60
2016	9	19,441.78	3,833.77	29,748.62	10,840.82	25,300.08
2016	10	17,723.67	3,517.08	27,591.29	11,786.51	25,214.40
2016	11	18,291.15	3,672.80	27,528.46	11,121.12	25,775.10
2016	12	24,033.42	4,422.93	29,840.95	11,109.95	25,354.20
2017	1	27,304.23	5,047.81	31,933.33	12,068.05	25,449.30
2017	2	22,847.85	4,299.36	27,545.15	10,526.63	25,249.80
2017	3	22,139.20	4,267.60	30,750.02	11,549.41	23,188.62
2017	4	19,024.10	3,717.31	25,797.79	11,171.64	25,853.82
2017	5	19,149.25	3,686.82	26,875.22	10,882.14	23,991.60
2017	6	19,040.70	3,856.96	31,337.54	11,595.97	25,216.86
2017	7	22,744.14	4,224.06	30,424.32	10,700.97	25,011.24
2017	8	22,751.84	4,411.17	32,027.77	12,645.18	25,111.38
2017	9	21,007.27	3,994.55	29,335.10	10,929.16	26,163.78
2017	10	18,860.14	3,750.90	27,569.89	12,888.24	15,731.46
2017	11	19,571.88	3,821.62	25,285.68	11,114.51	18,388.26
2017	12	22,633.55	4,114.81	29,574.10	11,245.15	23,648.34
2018	1	25,493.72	4,496.06	28,310.38	11,692.57	24,728.76
2018	2	24,537.40	4,538.62	27,716.30	9,768.55	26,398.26
2018	3	22,718.44	4,388.21	29,217.95	12,245.62	24,153.12
2018	4	21,234.25	4,033.19	26,482.45	10,221.90	25,758.84
2018	5	19,269.59	3,867.88	28,026.43	13,010.70	22,773.60
2018	6	19,658.83	3,807.06	28,152.75	10,918.04	25,269.12
2018	7	23,239.45	4,293.57	30,157.87	11,718.67	25,126.02
2018	8	22,640.19	4,242.50	30,338.31	13,364.91	25,181.46
2018	9	20,699.28	3,805.61	28,067.96	10,501.51	24,551.64
2018	10	19,379.12	3,858.28	26,613.52	12,468.71	24,970.38
2018	11	20,278.31	3,946.32	26,380.96	10,971.81	26,283.90
2018	12	24,260.37	4,109.29	27,861.04	10,603.92	25,630.20
2019	1	26,650.00	4,694.53	29,450.15	12,869.32	26,699.82
2019	2	23,836.63	4,321.01	26,717.02	11,202.01	25,842.60
2019	3	24,139.84	4,351.88	27,248.11	11,112.33	24,066.84
2019	4	21,308.16	4,031.88	26,405.99	10,843.06	27,143.46
2019	5	18,992.40	3,752.08	26,177.09	10,796.56	25,998.30
2019	6	18,983.45	3,678.27	27,073.50	12,701.98	26,949.48
2019	7	22,096.99	4,084.47	29,066.96	11,019.47	24,904.08
2019	8	25,262.47	4,487.33	30,306.02	12,598.98	25,984.98
2019	9	21,411.20	3,940.96	27,060.68	12,704.81	25,153.68
2019	10	19,524.53	3,955.37	27,522.09	11,782.71	22,171.50
2019	11	21,358.83	4,014.50	25,911.58	10,858.88	15,267.72
2019	12	24,806.48	4,564.57	27,608.17	10,371.80	21,575.40

Schedule C-3. Cheyenne Light: Historical and Forecasted Economic Data—Confidential

Confidential - Woods & Poole Economics — **Confidential Appendix C**

2019 Data Pamphlet - Laramie County — **Schedule C-3**

Cheyenne Light: Historical and Forecasted Economic Data

	Woods & Poole	Woods & Poole	Woods & Poole
Year	**Number of Households (thousands)**	**Total Employment (thousands of jobs)**	**Mean Real Household Total Personal Income (2012 $)**
2005	[redacted]	[redacted]	[redacted]
2006	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]
2008	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	[redacted]
2040	[redacted]	[redacted]	[redacted]

Schedule C-4. Cheyenne Light: Historical and Forecasted Weather Data Used in Demand Model

NOAA National Climatic Data Center **Confidential Appendix C**
Cheyenne Airport Weather Station **Schedule C-4**
Cheyenne Light: Historical and Forecasted Weather Data Used in Demand Model

Year	Month	Date	Hour	Demand Heating Degree Days	Demand Cooling Degree Days	Demand Heating Degree Hours	Demand Cooling Degree Hours	Demand Monthly Cooling Degree Day Daily Average
2008	1	1/21/08	18	62	0	54	0	0
2008	1	1/21/08	19	62	0	55	0	0
2008	1	1/21/08	20	62	0	55	0	0
2008	2	2/4/08	19	42	0	37	0	0
2008	3	3/6/08	19	38	0	27	0	0
2008	4	4/7/08	11	29	0	22	0	0
2008	4	4/7/08	21	29	0	20	0	0
2008	4	4/9/08	20	26	0	17	0	0
2008	5	5/2/08	11	30	0	20	0	0
2008	5	5/2/08	12	30	0	20	0	0
2008	5	5/2/08	13	30	0	20	0	0
2008	5	5/21/08	15	0	7	0	5	0
2008	6	6/30/08	18	0	8	0	12	3
2008	7	7/22/08	16	0	15	0	19	12
2008	7	7/22/08	17	0	15	0	17	12
2008	7	7/31/08	17	0	16	0	17	12
2008	8	8/1/08	15	0	20	0	24	7
2008	8	8/1/08	17	0	20	0	23	7
2008	9	9/1/08	16	0	4	0	0	1
2008	10	10/22/08	20	28	0	20	0	0
2008	11	11/6/08	18	29	0	17	0	0
2008	11	11/6/08	19	29	0	18	0	0
2008	11	11/30/08	18	31	0	25	0	0
2008	11	11/30/08	19	31	0	25	0	0
2008	12	12/14/08	18	67	0	59	0	0
2009	1	1/5/09	18	37	0	20	0	0
2009	1	1/27/09	18	56	0	35	0	0
2009	1	1/27/09	19	56	0	35	0	0
2009	2	2/2/09	19	27	0	14	0	0
2009	3	3/26/09	19	41	0	39	0	0
2009	3	3/26/09	20	41	0	39	0	0
2009	4	4/1/09	21	33	0	26	0	0
2009	4	4/4/09	21	38	0	33	0	0
2009	4	4/16/09	18	25	0	19	0	0
2009	4	4/16/09	19	25	0	19	0	0
2009	4	4/16/09	20	25	0	20	0	0
2009	5	5/18/09	16	0	6	0	11	1
2009	5	5/18/09	18	0	6	0	9	1
2009	5	5/19/09	13	0	8	0	8	1
2009	5	5/19/09	14	0	8	0	8	1
2009	5	5/19/09	15	0	8	0	7	1
2009	5	5/19/09	17	0	8	0	10	1

2009	5	5/19/09	18	0	8	0	7	1
2009	6	6/30/09	17	0	7	0	12	2
2009	7	7/24/09	14	0	14	0	19	6
2009	8	8/12/09	15	0	12	0	18	6
2009	8	8/12/09	16	0	12	0	18	6
2009	8	8/12/09	17	0	12	0	17	6
2009	9	9/2/09	15	0	9	0	13	2
2009	9	9/2/09	16	0	9	0	10	2
2009	9	9/2/09	17	0	9	0	9	2
2009	9	9/3/09	17	0	6	0	9	2
2009	9	9/10/09	15	0	6	0	13	2
2009	10	10/29/09	19	40	0	31	0	0
2009	11	11/23/09	18	31	0	24	0	0
2009	12	12/7/09	18	60	0	49	0	0
2009	12	12/7/09	19	60	0	50	0	0
2009	12	12/8/09	18	65	0	53	0	0
2009	12	12/8/09	19	65	0	54	0	0
2009	12	12/9/09	18	63	0	41	0	0
2010	1	1/6/10	18	45	0	49	0	0
2010	2	2/8/10	19	48	0	44	0	0
2010	3	3/10/10	19	32	0	24	0	0
2010	3	3/10/10	20	32	0	25	0	0
2010	4	4/22/10	21	19	0	14	0	0
2010	4	4/23/10	10	25	0	15	0	0
2010	4	4/23/10	11	25	0	14	0	0
2010	4	4/23/10	17	25	0	14	0	0
2010	4	4/23/10	21	25	0	17	0	0
2010	5	5/28/10	12	0	7	0	9	0
2010	5	5/28/10	13	0	7	0	11	0
2010	5	5/28/10	14	0	7	0	11	0
2010	5	5/28/10	15	0	7	0	12	0
2010	5	5/28/10	16	0	7	0	12	0
2010	5	5/28/10	17	0	7	0	13	0
2010	5	5/28/10	18	0	7	0	12	0
2010	5	5/28/10	19	0	7	0	11	0
2010	6	6/25/10	14	0	14	0	20	4
2010	6	6/25/10	15	0	14	0	19	4
2010	6	6/25/10	16	0	14	0	21	4
2010	6	6/25/10	17	0	14	0	21	4
2010	6	6/29/10	15	0	9	0	15	4
2010	6	6/29/10	16	0	9	0	15	4
2010	6	6/29/10	17	0	9	0	11	4
2010	7	7/26/10	15	0	13	0	20	9
2010	7	7/26/10	16	0	13	0	20	9
2010	8	8/11/10	16	0	12	0	19	9
2010	8	8/11/10	17	0	12	0	14	9
2010	9	9/28/10	16	0	8	0	18	3
2010	9	9/28/10	17	0	8	0	17	3

2010	9	9/28/10	18	0	8	0	13	3
2010	10	10/5/10	20	0	1	0	0	0
2010	10	10/7/10	15	0	3	0	6	0
2010	10	10/27/10	19	25	0	13	0	0
2010	10	10/27/10	20	25	0	18	0	0
2010	10	10/29/10	18	7	0	0	0	0
2010	11	11/24/10	18	39	0	41	0	0
2010	11	11/29/10	18	42	0	32	0	0
2010	11	11/29/10	19	42	0	34	0	0
2010	12	12/16/10	18	39	0	27	0	0
2010	12	12/30/10	18	47	0	50	0	0
2010	12	12/30/10	19	47	0	50	0	0
2011	1	1/31/11	19	54	0	55	0	0
2011	2	2/1/11	18	74	0	62	0	0
2011	2	2/1/11	19	74	0	65	0	0
2011	2	2/1/11	20	74	0	66	0	0
2011	3	3/7/11	19	45	0	31	0	0
2011	4	4/14/11	21	24	0	18	0	0
2011	5	5/11/11	11	24	0	17	0	0
2011	5	5/11/11	12	24	0	17	0	0
2011	5	5/11/11	13	24	0	16	0	0
2011	5	5/11/11	14	24	0	15	0	0
2011	5	5/11/11	21	24	0	16	0	0
2011	5	5/12/11	10	24	0	15	0	0
2011	5	5/12/11	11	24	0	14	0	0
2011	6	6/29/11	14	0	13	0	11	3
2011	7	7/18/11	16	0	14	0	18	11
2011	7	7/18/11	17	0	14	0	14	11
2011	8	8/25/11	14	0	12	0	20	10
2011	8	8/25/11	15	0	12	0	19	10
2011	8	8/31/11	16	0	12	0	16	10
2011	9	9/1/11	16	0	12	0	15	2
2011	9	9/1/11	17	0	12	0	15	2
2011	10	10/25/11	19	24	0	20	0	1
2011	11	11/3/11	9	36	0	28	0	0
2011	11	11/7/11	18	33	0	20	0	0
2011	11	11/8/11	18	31	0	19	0	0
2011	11	11/16/11	18	39	0	26	0	0
2011	11	11/16/11	19	39	0	26	0	0
2011	11	11/28/11	18	18	0	7	0	0
2011	11	11/30/11	18	19	0	8	0	0
2011	12	12/5/11	18	59	0	49	0	0
2012	1	1/11/12	18	44	0	42	0	0
2012	1	1/11/12	19	44	0	46	0	0
2012	2	2/2/12	19	31	0	22	0	0
2012	2	2/6/12	20	38	0	30	0	0
2012	2	2/7/12	19	41	0	31	0	0
2012	2	2/11/12	19	53	0	40	0	0

2012	2	2/20/12	19	36	0	26	0	0
2012	2	2/20/12	20	36	0	25	0	0
2012	3	3/2/12	19	40	0	30	0	0
2012	3	3/2/12	20	40	0	31	0	0
2012	3	3/7/12	19	36	0	23	0	0
2012	4	4/2/12	20	22	0	17	0	0
2012	4	4/2/12	21	22	0	17	0	0
2012	4	4/3/12	12	27	0	20	0	0
2012	4	4/10/12	21	5	0	0	0	0
2012	4	4/18/12	13	13	0	0	0	0
2012	4	4/23/12	12	2	0	0	4	0
2012	4	4/24/12	14	0	5	0	6	0
2012	4	4/25/12	13	0	1	0	3	0
2012	4	4/26/12	13	0	3	0	2	0
2012	4	4/26/12	14	0	3	0	4	0
2012	5	5/18/12	14	0	2	0	6	1
2012	5	5/21/12	13	0	1	0	6	1
2012	5	5/21/12	14	0	1	0	6	1
2012	5	5/21/12	15	0	1	0	8	1
2012	5	5/30/12	12	3	0	0	3	1
2012	6	6/25/12	16	0	16	0	24	8
2012	7	7/19/12	15	0	14	0	20	12
2012	7	7/20/12	16	0	15	0	21	12
2012	7	7/20/12	17	0	15	0	19	12
2012	7	7/23/12	14	0	17	0	20	12
2012	7	7/23/12	15	0	17	0	18	12
2012	8	8/8/12	17	0	14	0	18	9
2012	9	9/10/12	16	0	10	0	16	3
2012	9	9/10/12	17	0	10	0	14	3
2012	10	10/24/12	19	25	0	21	0	0
2012	11	11/26/12	18	35	0	25	0	0
2012	12	12/10/12	18	41	0	24	0	0
2012	12	12/10/12	19	41	0	26	0	0
2012	12	12/19/12	18	49	0	38	0	0
2012	12	12/19/12	19	49	0	40	0	0
2013	1	1/14/13	18	61	0	46	0	0
2013	1	1/14/13	19	61	0	52	0	0
2013	1	1/15/13	18	47	0	25	0	0
2013	1	1/15/13	19	47	0	23	0	0
2013	2	2/26/13	19	38	0	29	0	0
2013	2	2/26/13	20	38	0	29	0	0
2013	3	3/4/13	19	33	0	30	0	0
2013	3	3/4/13	20	33	0	31	0	0
2013	4	4/9/13	13	50	0	42	0	0
2013	4	4/9/13	21	50	0	44	0	0
2013	5	5/14/13	15	0	11	0	8	1
2013	5	5/15/13	14	0	3	0	3	1
2013	6	6/27/13	16	0	20	0	23	7

2013	6	6/27/13	17	0	20	0	20	7
2013	6	6/28/13	16	0	13	0	19	7
2013	6	6/28/13	17	0	13	0	19	7
2013	7	7/11/13	17	0	15	0	24	9
2013	7	7/11/13	18	0	15	0	22	9
2013	8	8/27/13	17	0	15	0	17	10
2013	8	8/28/13	15	0	15	0	19	10
2013	8	8/28/13	17	0	15	0	19	10
2013	9	9/3/13	14	0	16	0	20	4
2013	10	10/28/13	19	21	0	23	0	0
2013	11	11/21/13	18	49	0	40	0	0
2013	12	12/9/13	19	56	0	38	0	0
2013	12	12/19/13	18	35	0	39	0	0
2013	12	12/19/13	19	35	0	40	0	0
2014	1	1/5/14	18	58	0	51	0	0
2014	1	1/5/14	19	58	0	54	0	0
2014	2	2/4/14	18	55	0	51	0	0
2014	2	2/4/14	19	55	0	51	0	0
2014	2	2/4/14	20	55	0	53	0	0
2014	3	3/1/14	19	49	0	47	0	0
2014	4	4/13/14	21	30	0	32	0	0
2014	4	4/14/14	10	37	0	34	0	0
2014	4	4/29/14	21	27	0	16	0	0
2014	5	5/29/14	15	0	4	0	8	0
2014	6	6/17/14	16	0	6	0	10	3
2014	6	6/20/14	17	0	6	0	12	3
2014	6	6/26/14	17	0	8	0	10	3
2014	7	7/21/14	16	0	16	0	18	9
2014	7	7/21/14	17	0	16	0	19	9
2014	7	7/22/14	15	0	14	0	12	9
2014	8	8/13/14	17	0	14	0	15	7
2014	9	9/3/14	15	0	10	0	16	3
2014	9	9/3/14	16	0	10	0	19	3
2014	9	9/3/14	17	0	10	0	19	3
2014	9	9/3/14	18	0	10	0	19	3
2014	10	10/7/14	14	0	3	0	0	0
2014	10	10/7/14	15	0	3	0	1	0
2014	10	10/7/14	17	0	3	0	4	0
2014	10	10/8/14	14	2	0	0	0	0
2014	10	10/20/14	20	6	0	0	0	0
2014	10	10/23/14	14	7	0	0	0	0
2014	10	10/27/14	20	20	0	8	0	0
2014	11	11/12/14	18	66	0	50	0	0
2014	11	11/13/14	18	63	0	43	0	0
2014	11	11/24/14	18	36	0	23	0	0
2014	12	12/29/14	18	54	0	47	0	0
2014	12	12/30/14	19	71	0	60	0	0
2014	12	12/30/14	20	71	0	61	0	0

2015	1	1/3/15	19	45	0	48	0	0
2015	1	1/7/15	19	33	0	31	0	0
2015	2	2/4/15	19	32	0	29	0	0
2015	2	2/16/15	19	38	0	28	0	0
2015	3	3/3/15	19	38	0	41	0	0
2015	4	4/16/15	11	28	0	19	0	0
2015	4	4/16/15	12	28	0	18	0	0
2015	5	5/8/15	11	18	0	9	0	0
2015	5	5/8/15	12	18	0	9	0	0
2015	5	5/8/15	13	18	0	9	0	0
2015	5	5/9/15	21	27	0	26	0	0
2015	5	5/11/15	11	21	0	7	0	0
2015	5	5/11/15	12	21	0	6	0	0
2015	5	5/11/15	14	21	0	1	0	0
2015	6	6/19/15	14	0	15	0	17	6
2015	6	6/19/15	16	0	15	0	17	6
2015	6	6/29/15	14	0	11	0	10	6
2015	6	6/29/15	17	0	11	0	13	6
2015	6	6/30/15	14	0	12	0	14	6
2015	7	7/27/15	15	0	13	0	20	8
2015	7	7/27/15	16	0	13	0	19	8
2015	7	7/27/15	17	0	13	0	19	8
2015	7	7/27/15	18	0	13	0	18	8
2015	8	8/14/15	14	0	14	0	18	9
2015	8	8/14/15	15	0	14	0	19	9
2015	8	8/14/15	16	0	14	0	16	9
2015	9	9/2/15	16	0	15	0	18	5
2015	9	9/2/15	17	0	15	0	13	5
2015	9	9/2/15	18	0	15	0	12	5
2015	10	10/21/15	19	17	0	6	0	1
2015	10	10/22/15	19	19	0	10	0	1
2015	10	10/28/15	19	18	0	3	0	1
2015	11	11/30/15	18	41	0	32	0	0
2015	11	11/30/15	19	41	0	33	0	0
2015	12	12/28/15	18	46	0	37	0	0
2015	12	12/30/15	19	44	0	38	0	0
2015	12	12/31/15	18	49	0	42	0	0
2016	1	1/7/16	18	29	0	19	0	0
2016	1	1/8/16	18	42	0	36	0	0
2016	2	2/1/16	18	38	0	28	0	0
2016	3	3/7/16	18	22	0	15	0	0
2016	3	3/17/16	19	31	0	23	0	0
2016	3	3/18/16	9	38	0	29	0	0
2016	3	3/18/16	10	38	0	29	0	0
2016	4	4/1/16	12	28	0	16	0	0
2016	4	4/28/16	13	27	0	18	0	0
2016	4	4/29/16	9	28	0	18	0	0
2016	4	4/29/16	10	28	0	18	0	0

2016	4	4/29/16	12	28	0	17	0	0
2016	5	5/16/16	11	24	0	11	0	0
2016	6	6/21/16	14	0	16	0	23	7
2016	6	6/21/16	16	0	16	0	21	7
2016	7	7/21/16	15	0	16	0	21	11
2016	8	8/2/16	16	0	13	0	13	7
2016	8	8/9/16	16	0	13	0	20	7
2016	9	9/19/16	13	0	12	0	14	3
2016	10	10/3/16	12	2	0	0	0	0
2016	10	10/5/16	11	15	0	0	0	0
2016	11	11/29/16	18	35	0	24	0	0
2016	11	11/29/16	19	35	0	25	0	0
2016	12	12/7/16	18	63	0	57	0	0
2016	12	12/7/16	20	63	0	61	0	0
2017	1	1/4/17	18	55	0	49	0	0
2017	1	1/4/17	19	55	0	49	0	0
2017	2	2/2/17	19	47	0	33	0	0
2017	3	3/6/17	19	28	0	26	0	0
2017	3	3/6/17	20	28	0	27	0	0
2017	4	4/4/17	10	28	0	19	0	0
2017	4	4/4/17	11	28	0	17	0	0
2017	4	4/4/17	12	28	0	15	0	0
2017	4	4/4/17	21	28	0	19	0	0
2017	5	5/18/17	15	25	0	20	0	0
2017	5	5/18/17	16	25	0	19	0	0
2017	5	5/31/17	14	0	1	0	7	0
2017	6	6/21/17	16	0	16	0	15	5
2017	6	6/21/17	18	0	16	0	19	5
2017	7	7/19/17	15	0	20	0	27	12
2017	7	7/19/17	16	0	20	0	24	12
2017	7	7/19/17	17	0	20	0	21	12
2017	7	7/24/17	14	0	15	0	23	12
2017	8	8/28/17	16	0	10	0	16	7
2017	8	8/28/17	17	0	10	0	16	7
2017	9	9/12/17	17	0	12	0	17	4
2017	10	10/30/17	11	32	0	25	0	0
2017	11	11/7/17	18	37	0	27	0	0
2017	11	11/28/17	18	24	0	16	0	0
2017	12	12/26/17	18	56	0	47	0	0
2017	12	12/26/17	19	56	0	49	0	0
2018	1	1/15/18	18	50	0	43	0	0
2018	1	1/15/18	20	50	0	46	0	0
2018	2	2/12/18	18	49	0	37	0	0
2018	2	2/19/18	18	59	0	50	0	0
2018	2	2/19/18	19	59	0	51	0	0
2018	2	2/19/18	20	59	0	51	0	0
2018	3	3/5/18	19	33	0	25	0	0
2018	4	4/13/18	11	28	0	22	0	0

2018	4	4/24/18	10	27	0	20	0	0
2018	4	4/24/18	11	27	0	18	0	0
2018	5	5/17/18	15	0	5	0	8	1
2018	5	5/17/18	16	0	5	0	6	1
2018	5	5/17/18	17	0	5	0	8	1
2018	5	5/25/18	16	0	6	0	11	1
2018	6	6/28/18	14	0	21	0	26	7
2018	6	6/28/18	15	0	21	0	22	7
2018	6	6/28/18	17	0	21	0	28	7
2018	7	7/10/18	17	0	15	0	23	10
2018	8	8/9/18	18	0	9	0	12	7
2018	8	8/16/18	16	0	9	0	15	7
2018	8	8/16/18	17	0	9	0	14	7
2018	8	8/16/18	18	0	9	0	10	7
2018	9	9/12/18	17	0	11	0	16	5
2018	9	9/12/18	18	0	11	0	15	5
2018	9	9/13/18	17	0	12	0	18	5
2018	9	9/18/18	16	0	10	0	16	5
2018	9	9/18/18	17	0	10	0	13	5
2018	9	9/18/18	18	0	10	0	10	5
2018	10	10/10/18	12	32	0	21	0	0
2018	10	10/10/18	19	32	0	20	0	0
2018	10	10/10/18	20	32	0	20	0	0
2018	10	10/15/18	9	35	0	27	0	0
2018	11	11/12/18	18	42	0	29	0	0
2018	11	11/12/18	19	42	0	28	0	0
2018	11	11/17/18	18	38	0	36	0	0
2018	12	12/31/18	18	47	0	48	0	0
2019	1	1/28/19	19	40	0	32	0	0
2019	2	2/6/19	19	51	0	52	0	0
2019	2	2/6/19	20	51	0	52	0	0
2019	3	3/3/19	19	65	0	52	0	0
2019	3	3/3/19	20	65	0	56	0	0
2019	4	4/11/19	8	38	0	31	0	0
2019	4	4/11/19	11	38	0	25	0	0
2019	4	4/11/19	20	38	0	27	0	0
2019	5	5/20/19	10	27	0	17	0	0
2019	5	5/20/19	12	27	0	14	0	0
2019	5	5/20/19	14	27	0	15	0	0
2019	6	6/28/19	15	0	13	0	19	3
2019	6	6/28/19	16	0	13	0	18	3
2019	7	7/19/19	15	0	19	0	24	10
2019	7	7/19/19	16	0	19	0	24	10
2019	8	8/6/19	16	0	14	0	21	10
2019	9	9/5/19	15	0	17	0	18	5
2019	9	9/5/19	16	0	17	0	19	5
2019	10	10/30/19	19	49	0	36	0	0
2019	11	11/25/19	18	29	0	26	0	0

2019	11	11/26/19	19	48	0	39	0	0
2019	11	11/27/19	18	53	0	36	0	0
2019	12	12/16/19	18	45	0	34	0	0
2019	12	12/29/19	18	44	0	33	0	0
Forecasted Weather Normalization	1	0	0	47	0	40	0	0
Forecasted Weather Normalization	2	0	0	48	0	41	0	0
Forecasted Weather Normalization	3	0	0	37	0	31	0	0
Forecasted Weather Normalization	4	0	0	29	0	20	0	0
Forecasted Weather Normalization	5	0	0	0	6	0	9	1
Forecasted Weather Normalization	6	0	0	0	13	0	17	5
Forecasted Weather Normalization	7	0	0	0	16	0	20	11
Forecasted Weather Normalization	8	0	0	0	14	0	17	8
Forecasted Weather Normalization	9	0	0	0	10	0	13	3
Forecasted Weather Normalization	10	0	0	24	0	14	0	0
Forecasted Weather Normalization	11	0	0	40	0	30	0	0
Forecasted Weather Normalization	12	0	0	49	0	41	0	0

Schedule C-5. Cheyenne Light: Historical and Forecasted Weather Data Used in Sales Models

NOAA National Climatic Data Center **Confidential Appendix C**
Cheyenne Airport Weather Station **Schedule C-5**
Cheyenne Light: Historical and Forecasted Weather Data Used in Sales Models

Year	Month	Energy Heating Degree Days	Energy Cooling Degree Days
2005	1	984.25	0.00
2005	2	749.00	0.00
2005	3	711.50	0.00
2005	4	609.50	0.00
2005	5	489.25	0.00
2005	6	159.75	36.00
2005	7	1.00	289.25
2005	8	16.25	295.50
2005	9	16.50	213.50
2005	10	223.00	36.75
2005	11	451.75	0.00
2005	12	940.50	0.00
2006	1	728.75	0.00
2006	2	913.25	0.00
2006	3	902.25	0.00
2006	4	593.50	2.00
2006	5	413.00	0.00
2006	6	30.00	185.00
2006	7	3.00	215.25
2006	8	0.00	382.75
2006	9	55.50	109.50
2006	10	305.25	7.75
2006	11	637.00	0.00
2006	12	751.75	0.00
2007	1	1,139.75	0.00
2007	2	1,093.00	0.00
2007	3	661.75	0.00
2007	4	616.50	0.00
2007	5	307.00	18.50
2007	6	159.25	34.25
2007	7	0.00	306.75
2007	8	0.00	388.50
2007	9	48.00	197.25
2007	10	170.00	18.00
2007	11	454.00	0.00
2007	12	959.00	0.00
2008	1	1,082.75	0.00
2008	2	1,158.25	0.00
2008	3	754.75	0.00
2008	4	745.75	0.00
2008	5	460.75	0.00
2008	6	152.25	34.50

2008	7	0.00	217.75
2008	8	12.50	361.00
2008	9	120.25	79.75
2008	10	226.25	19.25
2008	11	491.25	0.00
2008	12	854.00	0.00
2009	1	1,013.75	0.00
2009	2	890.50	0.00
2009	3	692.00	0.00
2009	4	688.50	0.00
2009	5	420.25	3.50
2009	6	153.50	21.25
2009	7	3.50	153.25
2009	8	13.50	201.50
2009	9	26.00	137.75
2009	10	478.00	4.00
2009	11	614.50	0.00
2009	12	1,029.25	0.00
2010	1	1,020.25	0.00
2010	2	988.25	0.00
2010	3	857.75	0.00
2010	4	650.50	0.00
2010	5	551.00	0.00
2010	6	135.75	45.75
2010	7	11.00	176.00
2010	8	0.00	306.75
2010	9	22.25	185.50
2010	10	104.75	49.25
2010	11	544.25	0.00
2010	12	833.75	0.00
2011	1	1,062.25	0.00
2011	2	1,079.00	0.00
2011	3	768.75	0.00
2011	4	570.00	0.00
2011	5	509.00	1.25
2011	6	202.50	35.00
2011	7	19.75	196.50
2011	8	0.00	342.25
2011	9	52.00	211.00
2011	10	169.25	50.25
2011	11	690.25	0.00
2011	12	927.50	0.00
2012	1	861.00	0.00
2012	2	1,003.00	0.00
2012	3	752.00	0.00
2012	4	368.50	0.00
2012	5	267.75	10.50
2012	6	79.50	90.25

2012	7	3.50	329.75
2012	8	0.00	372.00
2012	9	21.25	208.25
2012	10	268.75	12.00
2012	11	558.00	0.00
2012	12	669.50	0.00
2013	1	1,200.75	0.00
2013	2	876.00	0.00
2013	3	814.50	0.00
2013	4	814.00	0.00
2013	5	553.50	20.00
2013	6	94.25	86.00
2013	7	0.00	313.25
2013	8	0.00	222.25
2013	9	14.50	303.75
2013	10	283.25	20.50
2013	11	607.00	0.00
2013	12	1,009.50	0.00
2014	1	908.00	0.00
2014	2	1,125.25	0.00
2014	3	751.50	0.00
2014	4	634.50	0.00
2014	5	414.00	1.25
2014	6	91.00	33.50
2014	7	5.50	182.50
2014	8	2.00	271.25
2014	9	76.50	116.75
2014	10	145.50	77.50
2014	11	556.50	3.00
2014	12	716.75	0.00
2015	1	1,124.25	0.00
2015	2	643.00	0.00
2015	3	861.75	2.75
2015	4	452.50	0.00
2015	5	435.50	0.00
2015	6	185.50	50.00
2015	7	11.00	229.00
2015	8	0.00	307.50
2015	9	15.00	221.00
2015	10	76.50	65.75
2015	11	460.00	0.00
2015	12	869.75	0.00
2016	1	1,128.50	0.00
2016	2	847.25	0.00
2016	3	552.00	0.00
2016	4	624.00	0.00
2016	5	505.00	1.00
2016	6	134.75	78.75

2016	7	0.00	290.25
2016	8	0.00	339.25
2016	9	50.00	129.00
2016	10	156.50	51.75
2016	11	276.25	3.50
2016	12	930.50	0.00
2017	1	1,051.25	0.00
2017	2	825.75	0.00
2017	3	639.75	0.00
2017	4	432.00	0.00
2017	5	374.75	6.00
2017	6	184.50	53.25
2017	7	8.00	258.00
2017	8	5.00	271.25
2017	9	0.50	254.25
2017	10	335.50	3.75
2017	11	534.75	3.50
2017	12	592.25	0.00
2018	1	965.75	0.00
2018	2	912.50	0.00
2018	3	831.50	0.00
2018	4	644.75	0.00
2018	5	322.25	0.50
2018	6	58.00	133.75
2018	7	17.75	257.00
2018	8	1.00	254.75
2018	9	15.75	191.75
2018	10	368.50	51.50
2018	11	585.00	0.00
2018	12	856.25	0.00
2019	1	893.25	0.00
2019	2	939.75	0.00
2019	3	1,013.25	0.00
2019	4	630.00	0.00
2019	5	397.75	0.00
2019	6	259.75	27.25
2019	7	38.50	177.00
2019	8	0.00	361.00
2019	9	4.00	256.25
2019	10	255.25	42.00
2019	11	737.00	0.00
2019	12	833.50	0.00
Forecasted Weather Normalization	1	994.80	0.00
Forecasted Weather Normalization	2	947.16	0.00
Forecasted Weather Normalization	3	769.29	0.14
Forecasted Weather Normalization	4	602.21	0.35
Forecasted Weather Normalization	5	413.19	6.09
Forecasted Weather Normalization	6	132.60	66.40

Forecasted Weather Normalization	7	13.51	246.26
Forecasted Weather Normalization	8	3.99	317.63
Forecasted Weather Normalization	9	34.94	185.68
Forecasted Weather Normalization	10	248.80	30.99
Forecasted Weather Normalization	11	561.64	1.58
Forecasted Weather Normalization	12	852.79	0.00

Schedule C-6. Cheyenne Light: Historical and Forecasted Variable Values for Demand Model

Cheyenne Light **Confidential Appendix C**

Cheyenne Light: Historical and Forecasted Variable Values for Demand Model **Schedule C-6**

Year	Month	Date	Hour	cdd60	hdd60	cdh	hdh	mnthcdd60per day	lntotemp	m1	m2	m3	m4	m5	m6	m7	m8	m9	m10	m11	m12	ln(mwNlvc)
2008	1	1/21/08	18	-	61.75	-	54.00	-	4.13	1	-	-	-	-	-	-	-	-	-	-	-	5.11
2008	1	1/21/08	19	-	61.75	-	55.00	-	4.13	1	-	-	-	-	-	-	-	-	-	-	-	5.12
2008	1	1/21/08	20	-	61.75	-	55.00	-	4.13	1	-	-	-	-	-	-	-	-	-	-	-	5.12
2008	2	2/4/08	19	-	42.00	-	37.00	-	4.13	-	1	-	-	-	-	-	-	-	-	-	-	5.08
2008	3	3/6/08	19	-	37.50	-	27.00	-	4.13	-	-	1	-	-	-	-	-	-	-	-	-	5.02
2008	4	4/7/08	11	-	29.00	-	22.00	-	4.13	-	-	-	1	-	-	-	-	-	-	-	-	4.97
2008	4	4/7/08	21	-	29.00	-	19.50	-	4.13	-	-	-	1	-	-	-	-	-	-	-	-	4.97
2008	4	4/9/08	20	-	25.75	-	17.00	-	4.13	-	-	-	1	-	-	-	-	-	-	-	-	4.96
2008	5	5/2/08	11	-	29.75	-	19.50	0.42	4.13	-	-	-	-	1	-	-	-	-	-	-	-	4.96
2008	5	5/2/08	12	-	29.75	-	19.50	0.42	4.13	-	-	-	-	1	-	-	-	-	-	-	-	4.96
2008	5	5/2/08	13	-	29.75	-	19.50	0.42	4.13	-	-	-	-	1	-	-	-	-	-	-	-	4.96
2008	5	5/21/08	15	7.00	-	5.00	-	0.42	4.13	-	-	-	-	1	-	-	-	-	-	-	-	4.97
2008	6	6/30/08	18	8.00	-	12.00	-	3.16	4.13	-	-	-	-	-	1	-	-	-	-	-	-	5.06
2008	7	7/22/08	16	14.50	-	19.00	-	11.86	4.13	-	-	-	-	-	-	1	-	-	-	-	-	5.20
2008	7	7/22/08	17	14.50	-	17.00	-	11.86	4.13	-	-	-	-	-	-	1	-	-	-	-	-	5.19
2008	7	7/31/08	17	16.00	-	17.00	-	11.86	4.13	-	-	-	-	-	-	1	-	-	-	-	-	5.20
2008	8	8/1/08	15	19.50	-	24.00	-	6.78	4.13	-	-	-	-	-	-	-	1	-	-	-	-	5.17
2008	8	8/1/08	17	19.50	-	23.00	-	6.78	4.13	-	-	-	-	-	-	-	1	-	-	-	-	5.17
2008	9	9/1/08	16	3.50	-	-	-	0.88	4.13	-	-	-	-	-	-	-	-	1	-	-	-	4.99
2008	10	10/22/08	20	-	28.25	-	20.00	-	4.13	-	-	-	-	-	-	-	-	-	1	-	-	4.98
2008	11	11/6/08	18	-	28.50	-	16.50	-	4.13	-	-	-	-	-	-	-	-	-	-	1	-	5.04
2008	11	11/6/08	19	-	28.50	-	18.00	-	4.13	-	-	-	-	-	-	-	-	-	-	1	-	5.04
2008	11	11/30/08	18	-	31.00	-	25.00	-	4.13	-	-	-	-	-	-	-	-	-	-	1	-	5.04
2008	11	11/30/08	19	-	31.00	-	25.00	-	4.13	-	-	-	-	-	-	-	-	-	-	1	-	5.04
2008	12	12/14/08	18	-	67.00	-	59.00	-	4.13	-	-	-	-	-	-	-	-	-	-	-	1	5.14
2009	1	1/5/09	18	-	36.50	-	20.00	-	4.12	1	-	-	-	-	-	-	-	-	-	-	-	5.07
2009	1	1/27/09	18	-	56.25	-	34.50	-	4.12	1	-	-	-	-	-	-	-	-	-	-	-	5.09
2009	1	1/27/09	19	-	56.25	-	35.00	-	4.12	1	-	-	-	-	-	-	-	-	-	-	-	5.09
2009	2	2/2/09	19	-	26.50	-	14.00	-	4.12	-	1	-	-	-	-	-	-	-	-	-	-	5.05
2009	3	3/26/09	19	-	41.25	-	39.00	-	4.12	-	-	1	-	-	-	-	-	-	-	-	-	5.03
2009	3	3/26/09	20	-	41.25	-	39.00	-	4.12	-	-	1	-	-	-	-	-	-	-	-	-	5.03

2009	4	4/1/09	21	-	32.50	-	26.00	0.02	4.12	-	-	-	1	-	-	-	-	-	-	-	-	4.97
2009	4	4/4/09	21	-	38.00	-	32.50	0.02	4.12	-	-	-	1	-	-	-	-	-	-	-	-	4.97
2009	4	4/16/09	18	-	25.25	-	19.00	0.02	4.12	-	-	-	1	-	-	-	-	-	-	-	-	4.96
2009	4	4/16/09	19	-	25.25	-	19.00	0.02	4.12	-	-	-	1	-	-	-	-	-	-	-	-	4.96
2009	4	4/16/09	20	-	25.25	-	20.00	0.02	4.12	-	-	-	1	-	-	-	-	-	-	-	-	4.96
2009	5	5/18/09	16	5.50	-	11.00	-	0.78	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.98
2009	5	5/18/09	18	5.50	-	9.00	-	0.78	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.97
2009	5	5/19/09	13	7.50	-	8.00	-	0.78	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.98
2009	5	5/19/09	14	7.50	-	8.00	-	0.78	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.98
2009	5	5/19/09	15	7.50	-	7.00	-	0.78	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.98
2009	5	5/19/09	17	7.50	-	10.00	-	0.78	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.98
2009	5	5/19/09	18	7.50	-	7.00	-	0.78	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.98
2009	6	6/30/09	17	6.50	-	12.00	-	2.30	4.12	-	-	-	-	-	1	-	-	-	-	-	-	5.04
2009	7	7/24/09	14	13.50	-	19.00	-	5.85	4.12	-	-	-	-	-	-	1	-	-	-	-	-	5.14
2009	8	8/12/09	15	12.00	-	18.00	-	5.65	4.12	-	-	-	-	-	-	-	1	-	-	-	-	5.11
2009	8	8/12/09	16	12.00	-	18.00	-	5.65	4.12	-	-	-	-	-	-	-	1	-	-	-	-	5.11
2009	8	8/12/09	17	12.00	-	17.00	-	5.65	4.12	-	-	-	-	-	-	-	1	-	-	-	-	5.11
2009	9	9/2/09	15	9.00	-	13.00	-	2.37	4.12	-	-	-	-	-	-	-	-	1	-	-	-	5.05
2009	9	9/2/09	16	9.00	-	10.00	-	2.37	4.12	-	-	-	-	-	-	-	-	1	-	-	-	5.04
2009	9	9/2/09	17	9.00	-	9.00	-	2.37	4.12	-	-	-	-	-	-	-	-	1	-	-	-	5.04
2009	9	9/3/09	17	6.25	-	9.00	-	2.37	4.12	-	-	-	-	-	-	-	-	1	-	-	-	5.03
2009	9	9/10/09	15	5.50	-	13.00	-	2.37	4.12	-	-	-	-	-	-	-	-	1	-	-	-	5.03
2009	10	10/29/09	19	-	39.50	-	30.50	-	4.12	-	-	-	-	-	-	-	-	-	1	-	-	4.99
2009	11	11/23/09	18	-	31.25	-	24.00	-	4.12	-	-	-	-	-	-	-	-	-	-	1	-	5.04
2009	12	12/7/09	18	-	59.50	-	49.00	-	4.12	-	-	-	-	-	-	-	-	-	-	-	1	5.13
2009	12	12/7/09	19	-	59.50	-	49.50	-	4.12	-	-	-	-	-	-	-	-	-	-	-	1	5.13
2009	12	12/8/09	18	-	64.75	-	53.00	-	4.12	-	-	-	-	-	-	-	-	-	-	-	1	5.13
2009	12	12/8/09	19	-	64.75	-	54.00	-	4.12	-	-	-	-	-	-	-	-	-	-	-	1	5.13
2009	12	12/9/09	18	-	63.00	-	41.00	-	4.12	-	-	-	-	-	-	-	-	-	-	-	1	5.12
2010	1	1/6/10	18	-	45.00	-	49.00	-	4.12	1	-	-	-	-	-	-	-	-	-	-	-	5.09
2010	2	2/8/10	19	-	47.50	-	44.00	-	4.12	-	1	-	-	-	-	-	-	-	-	-	-	5.08
2010	3	3/10/10	19	-	31.50	-	23.50	-	4.12	-	-	1	-	-	-	-	-	-	-	-	-	5.01
2010	3	3/10/10	20	-	31.50	-	25.00	-	4.12	-	-	1	-	-	-	-	-	-	-	-	-	5.01
2010	4	4/22/10	21	-	19.00	-	14.00	-	4.12	-	-	-	1	-	-	-	-	-	-	-	-	4.95
2010	4	4/23/10	10	-	24.50	-	15.00	-	4.12	-	-	-	1	-	-	-	-	-	-	-	-	4.95

2010	4	4/23/10	11	-	24.50	-	14.00	-	4.12	-	-	-	1	-	-	-	-	-	-	-	-	4.95
2010	4	4/23/10	17	-	24.50	-	14.00	-	4.12	-	-	-	1	-	-	-	-	-	-	-	-	4.95
2010	4	4/23/10	21	-	24.50	-	17.00	-	4.12	-	-	-	1	-	-	-	-	-	-	-	-	4.95
2010	5	5/28/10	12	6.50	-	9.00	-	0.43	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.97
2010	5	5/28/10	13	6.50	-	10.50	-	0.43	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.97
2010	5	5/28/10	14	6.50	-	11.00	-	0.43	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.98
2010	5	5/28/10	15	6.50	-	12.00	-	0.43	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.98
2010	5	5/28/10	16	6.50	-	12.00	-	0.43	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.98
2010	5	5/28/10	17	6.50	-	13.00	-	0.43	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.98
2010	5	5/28/10	18	6.50	-	12.00	-	0.43	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.98
2010	5	5/28/10	19	6.50	-	11.00	-	0.43	4.12	-	-	-	-	1	-	-	-	-	-	-	-	4.98
2010	6	6/25/10	14	14.00	-	20.00	-	3.84	4.12	-	-	-	-	-	1	-	-	-	-	-	-	5.11
2010	6	6/25/10	15	14.00	-	19.00	-	3.84	4.12	-	-	-	-	-	1	-	-	-	-	-	-	5.10
2010	6	6/25/10	16	14.00	-	20.50	-	3.84	4.12	-	-	-	-	-	1	-	-	-	-	-	-	5.11
2010	6	6/25/10	17	14.00	-	21.00	-	3.84	4.12	-	-	-	-	-	1	-	-	-	-	-	-	5.11
2010	6	6/29/10	15	9.00	-	15.00	-	3.84	4.12	-	-	-	-	-	1	-	-	-	-	-	-	5.07
2010	6	6/29/10	16	9.00	-	15.00	-	3.84	4.12	-	-	-	-	-	1	-	-	-	-	-	-	5.07
2010	6	6/29/10	17	9.00	-	11.00	-	3.84	4.12	-	-	-	-	-	1	-	-	-	-	-	-	5.06
2010	7	7/26/10	15	12.50	-	20.00	-	8.50	4.12	-	-	-	-	-	-	1	-	-	-	-	-	5.15
2010	7	7/26/10	16	12.50	-	20.00	-	8.50	4.12	-	-	-	-	-	-	1	-	-	-	-	-	5.15
2010	8	8/11/10	16	12.00	-	19.00	-	8.77	4.12	-	-	-	-	-	-	-	1	-	-	-	-	5.13
2010	8	8/11/10	17	12.00	-	14.00	-	8.77	4.12	-	-	-	-	-	-	-	1	-	-	-	-	5.12
2010	9	9/28/10	16	7.50	-	18.00	-	3.18	4.12	-	-	-	-	-	-	-	-	1	-	-	-	5.06
2010	9	9/28/10	17	7.50	-	17.00	-	3.18	4.12	-	-	-	-	-	-	-	-	1	-	-	-	5.05
2010	9	9/28/10	18	7.50	-	13.00	-	3.18	4.12	-	-	-	-	-	-	-	-	1	-	-	-	5.05
2010	10	10/5/10	20	1.00	-	-	-	0.13	4.12	-	-	-	-	-	-	-	-	-	1	-	-	4.95
2010	10	10/7/10	15	3.00	-	6.00	-	0.13	4.12	-	-	-	-	-	-	-	-	-	1	-	-	4.97
2010	10	10/27/10	19	-	25.00	-	13.00	0.13	4.12	-	-	-	-	-	-	-	-	-	1	-	-	4.97
2010	10	10/27/10	20	-	25.00	-	18.00	0.13	4.12	-	-	-	-	-	-	-	-	-	1	-	-	4.97
2010	10	10/29/10	18	-	7.00	-	-	0.13	4.12	-	-	-	-	-	-	-	-	-	1	-	-	4.95
2010	11	11/24/10	18	-	38.50	-	40.50	-	4.12	-	-	-	-	-	-	-	-	-	-	1	-	5.05
2010	11	11/29/10	18	-	42.00	-	32.00	-	4.12	-	-	-	-	-	-	-	-	-	-	1	-	5.05
2010	11	11/29/10	19	-	42.00	-	34.00	-	4.12	-	-	-	-	-	-	-	-	-	-	1	-	5.05
2010	12	12/16/10	18	-	38.50	-	27.00	-	4.12	-	-	-	-	-	-	-	-	-	-	-	1	5.09
2010	12	12/30/10	18	-	46.50	-	49.50	-	4.12	-	-	-	-	-	-	-	-	-	-	-	1	5.12

2010	12	12/30/10	19	-	46.50	-	50.00	-	4.12	-	-	-	-	-	-	-	-	-	-	-	1	5.12
2011	1	1/31/11	19	-	53.75	-	55.00	-	4.14	1	-	-	-	-	-	-	-	-	-	-	-	5.12
2011	2	2/1/11	18	-	74.00	-	62.00	-	4.14	-	1	-	-	-	-	-	-	-	-	-	-	5.12
2011	2	2/1/11	19	-	74.00	-	65.00	-	4.14	-	1	-	-	-	-	-	-	-	-	-	-	5.13
2011	2	2/1/11	20	-	74.00	-	66.00	-	4.14	-	1	-	-	-	-	-	-	-	-	-	-	5.13
2011	3	3/7/11	19	-	45.25	-	31.00	-	4.14	-	-	1	-	-	-	-	-	-	-	-	-	5.04
2011	4	4/14/11	21	-	24.00	-	18.00	-	4.14	-	-	-	1	-	-	-	-	-	-	-	-	4.97
2011	5	5/11/11	11	-	24.25	-	17.00	0.04	4.14	-	-	-	-	1	-	-	-	-	-	-	-	4.96
2011	5	5/11/11	12	-	24.25	-	17.00	0.04	4.14	-	-	-	-	1	-	-	-	-	-	-	-	4.96
2011	5	5/11/11	13	-	24.25	-	16.00	0.04	4.14	-	-	-	-	1	-	-	-	-	-	-	-	4.96
2011	5	5/11/11	14	-	24.25	-	15.00	0.04	4.14	-	-	-	-	1	-	-	-	-	-	-	-	4.96
2011	5	5/11/11	21	-	24.25	-	16.00	0.04	4.14	-	-	-	-	1	-	-	-	-	-	-	-	4.96
2011	5	5/12/11	10	-	23.50	-	15.00	0.04	4.14	-	-	-	-	1	-	-	-	-	-	-	-	4.96
2011	5	5/12/11	11	-	23.50	-	13.50	0.04	4.14	-	-	-	-	1	-	-	-	-	-	-	-	4.96
2011	6	6/29/11	14	13.25	-	11.00	-	3.19	4.14	-	-	-	-	-	1	-	-	-	-	-	-	5.09
2011	7	7/18/11	16	13.50	-	18.00	-	10.87	4.14	-	-	-	-	-	-	1	-	-	-	-	-	5.19
2011	7	7/18/11	17	13.50	-	14.00	-	10.87	4.14	-	-	-	-	-	-	1	-	-	-	-	-	5.18
2011	8	8/25/11	14	12.00	-	20.00	-	10.33	4.14	-	-	-	-	-	-	-	1	-	-	-	-	5.16
2011	8	8/25/11	15	12.00	-	19.00	-	10.33	4.14	-	-	-	-	-	-	-	1	-	-	-	-	5.16
2011	8	8/31/11	16	12.00	-	16.00	-	10.33	4.14	-	-	-	-	-	-	-	1	-	-	-	-	5.15
2011	9	9/1/11	16	12.00	-	15.00	-	2.14	4.14	-	-	-	-	-	-	-	-	1	-	-	-	5.08
2011	9	9/1/11	17	12.00	-	15.00	-	2.14	4.14	-	-	-	-	-	-	-	-	1	-	-	-	5.08
2011	10	10/25/11	19	-	23.50	-	20.00	0.57	4.14	-	-	-	-	-	-	-	-	-	1	-	-	4.99
2011	11	11/3/11	9	-	36.25	-	28.00	-	4.14	-	-	-	-	-	-	-	-	-	-	1	-	5.06
2011	11	11/7/11	18	-	33.00	-	20.00	-	4.14	-	-	-	-	-	-	-	-	-	-	1	-	5.05
2011	11	11/8/11	18	-	31.00	-	19.00	-	4.14	-	-	-	-	-	-	-	-	-	-	1	-	5.05
2011	11	11/16/11	18	-	39.00	-	26.00	-	4.14	-	-	-	-	-	-	-	-	-	-	1	-	5.06
2011	11	11/16/11	19	-	39.00	-	26.00	-	4.14	-	-	-	-	-	-	-	-	-	-	1	-	5.06
2011	11	11/28/11	18	-	18.00	-	7.00	-	4.14	-	-	-	-	-	-	-	-	-	-	1	-	5.03
2011	11	11/30/11	18	-	19.25	-	7.50	-	4.14	-	-	-	-	-	-	-	-	-	-	1	-	5.03
2011	12	12/5/11	18	-	59.00	-	48.50	-	4.14	-	-	-	-	-	-	-	-	-	-	-	1	5.14
2012	1	1/11/12	18	-	44.00	-	42.00	-	4.15	1	-	-	-	-	-	-	-	-	-	-	-	5.11
2012	1	1/11/12	19	-	44.00	-	46.00	-	4.15	1	-	-	-	-	-	-	-	-	-	-	-	5.11
2012	2	2/2/12	19	-	30.50	-	22.00	-	4.15	-	1	-	-	-	-	-	-	-	-	-	-	5.07
2012	2	2/6/12	20	-	37.50	-	29.50	-	4.15	-	1	-	-	-	-	-	-	-	-	-	-	5.08

2012	2	2/7/12	19	-	41.00	-	31.00	-	4.15	-	1	-	-	-	-	-	-	-	-	-	-	5.09
2012	2	2/11/12	19	-	52.50	-	40.00	-	4.15	-	1	-	-	-	-	-	-	-	-	-	-	5.10
2012	2	2/20/12	19	-	36.00	-	26.00	-	4.15	-	1	-	-	-	-	-	-	-	-	-	-	5.08
2012	2	2/20/12	20	-	36.00	-	25.00	-	4.15	-	1	-	-	-	-	-	-	-	-	-	-	5.08
2012	3	3/2/12	19	-	40.00	-	30.00	-	4.15	-	-	1	-	-	-	-	-	-	-	-	-	5.04
2012	3	3/2/12	20	-	40.00	-	31.00	-	4.15	-	-	1	-	-	-	-	-	-	-	-	-	5.04
2012	3	3/7/12	19	-	35.75	-	23.00	-	4.15	-	-	1	-	-	-	-	-	-	-	-	-	5.03
2012	4	4/2/12	20	-	21.50	-	17.00	0.25	4.15	-	-	-	1	-	-	-	-	-	-	-	-	4.97
2012	4	4/2/12	21	-	21.50	-	16.50	0.25	4.15	-	-	-	1	-	-	-	-	-	-	-	-	4.97
2012	4	4/3/12	12	-	27.00	-	19.50	0.25	4.15	-	-	-	1	-	-	-	-	-	-	-	-	4.98
2012	4	4/10/12	21	-	4.50	-	-	0.25	4.15	-	-	-	1	-	-	-	-	-	-	-	-	4.95
2012	4	4/18/12	13	-	13.00	-	-	0.25	4.15	-	-	-	1	-	-	-	-	-	-	-	-	4.96
2012	4	4/23/12	12	-	1.50	4.00	-	0.25	4.15	-	-	-	1	-	-	-	-	-	-	-	-	4.96
2012	4	4/24/12	14	4.50	-	6.00	-	0.25	4.15	-	-	-	1	-	-	-	-	-	-	-	-	4.98
2012	4	4/25/12	13	0.50	-	2.50	-	0.25	4.15	-	-	-	1	-	-	-	-	-	-	-	-	4.96
2012	4	4/26/12	13	2.50	-	1.50	-	0.25	4.15	-	-	-	1	-	-	-	-	-	-	-	-	4.96
2012	4	4/26/12	14	2.50	-	4.00	-	0.25	4.15	-	-	-	1	-	-	-	-	-	-	-	-	4.97
2012	5	5/18/12	14	2.00	-	6.00	-	0.76	4.15	-	-	-	-	1	-	-	-	-	-	-	-	4.97
2012	5	5/21/12	13	1.00	-	5.50	-	0.76	4.15	-	-	-	-	1	-	-	-	-	-	-	-	4.96
2012	5	5/21/12	14	1.00	-	6.00	-	0.76	4.15	-	-	-	-	1	-	-	-	-	-	-	-	4.96
2012	5	5/21/12	15	1.00	-	8.00	-	0.76	4.15	-	-	-	-	1	-	-	-	-	-	-	-	4.97
2012	5	5/30/12	12	-	2.50	3.00	-	0.76	4.15	-	-	-	-	1	-	-	-	-	-	-	-	4.96
2012	6	6/25/12	16	16.00	-	24.00	-	7.97	4.15	-	-	-	-	-	1	-	-	-	-	-	-	5.18
2012	7	7/19/12	15	13.50	-	20.00	-	12.05	4.15	-	-	-	-	-	-	1	-	-	-	-	-	5.21
2012	7	7/20/12	16	14.50	-	21.00	-	12.05	4.15	-	-	-	-	-	-	1	-	-	-	-	-	5.22
2012	7	7/20/12	17	14.50	-	19.00	-	12.05	4.15	-	-	-	-	-	-	1	-	-	-	-	-	5.21
2012	7	7/23/12	14	16.50	-	20.00	-	12.05	4.15	-	-	-	-	-	-	1	-	-	-	-	-	5.22
2012	7	7/23/12	15	16.50	-	18.00	-	12.05	4.15	-	-	-	-	-	-	1	-	-	-	-	-	5.22
2012	8	8/8/12	17	13.50	-	18.00	-	9.35	4.15	-	-	-	-	-	-	-	1	-	-	-	-	5.17
2012	9	9/10/12	16	9.75	-	16.00	-	2.90	4.15	-	-	-	-	-	-	-	-	1	-	-	-	5.08
2012	9	9/10/12	17	9.75	-	14.00	-	2.90	4.15	-	-	-	-	-	-	-	-	1	-	-	-	5.08
2012	10	10/24/12	19	-	25.25	-	20.50	0.08	4.15	-	-	-	-	-	-	-	-	-	1	-	-	5.00
2012	11	11/26/12	18	-	35.00	-	24.50	-	4.15	-	-	-	-	-	-	-	-	-	-	1	-	5.06
2012	12	12/10/12	18	-	40.50	-	23.50	-	4.15	-	-	-	-	-	-	-	-	-	-	-	1	5.12
2012	12	12/10/12	19	-	40.50	-	26.00	-	4.15	-	-	-	-	-	-	-	-	-	-	-	1	5.12

2012	12	12/19/12	18	-	49.00	-	37.50	-	4.15	-	-	-	-	-	-	-	-	-	-	-	1	5.13
2012	12	12/19/12	19	-	49.00	-	40.00	-	4.15	-	-	-	-	-	-	-	-	-	-	-	1	5.13
2013	1	1/14/13	18	-	61.00	-	46.00	-	4.18	1	-	-	-	-	-	-	-	-	-	-	-	5.14
2013	1	1/14/13	19	-	61.00	-	52.00	-	4.18	1	-	-	-	-	-	-	-	-	-	-	-	5.15
2013	1	1/15/13	18	-	47.00	-	24.50	-	4.18	1	-	-	-	-	-	-	-	-	-	-	-	5.12
2013	1	1/15/13	19	-	47.00	-	23.00	-	4.18	1	-	-	-	-	-	-	-	-	-	-	-	5.12
2013	2	2/26/13	19	-	38.00	-	28.50	-	4.18	-	1	-	-	-	-	-	-	-	-	-	-	5.11
2013	2	2/26/13	20	-	38.00	-	28.50	-	4.18	-	1	-	-	-	-	-	-	-	-	-	-	5.11
2013	3	3/4/13	19	-	32.50	-	30.00	-	4.18	-	-	1	-	-	-	-	-	-	-	-	-	5.06
2013	3	3/4/13	20	-	32.50	-	31.00	-	4.18	-	-	1	-	-	-	-	-	-	-	-	-	5.06
2013	4	4/9/13	13	-	50.25	-	41.50	-	4.18	-	-	-	1	-	-	-	-	-	-	-	-	5.03
2013	4	4/9/13	21	-	50.25	-	43.50	-	4.18	-	-	-	1	-	-	-	-	-	-	-	-	5.03
2013	5	5/14/13	15	10.50	-	8.00	-	1.13	4.18	-	-	-	-	1	-	-	-	-	-	-	-	5.04
2013	5	5/15/13	14	3.00	-	3.00	-	1.13	4.18	-	-	-	-	1	-	-	-	-	-	-	-	4.99
2013	6	6/27/13	16	19.50	-	23.00	-	7.23	4.18	-	-	-	-	-	1	-	-	-	-	-	-	5.21
2013	6	6/27/13	17	19.50	-	20.00	-	7.23	4.18	-	-	-	-	-	1	-	-	-	-	-	-	5.20
2013	6	6/28/13	16	13.00	-	19.00	-	7.23	4.18	-	-	-	-	-	1	-	-	-	-	-	-	5.17
2013	6	6/28/13	17	13.00	-	19.00	-	7.23	4.18	-	-	-	-	-	1	-	-	-	-	-	-	5.17
2013	7	7/11/13	17	15.00	-	24.00	-	9.32	4.18	-	-	-	-	-	-	1	-	-	-	-	-	5.22
2013	7	7/11/13	18	15.00	-	22.00	-	9.32	4.18	-	-	-	-	-	-	1	-	-	-	-	-	5.22
2013	8	8/27/13	17	14.50	-	17.00	-	9.59	4.18	-	-	-	-	-	-	-	1	-	-	-	-	5.19
2013	8	8/28/13	15	15.00	-	19.00	-	9.59	4.18	-	-	-	-	-	-	-	1	-	-	-	-	5.20
2013	8	8/28/13	17	15.00	-	19.00	-	9.59	4.18	-	-	-	-	-	-	-	1	-	-	-	-	5.20
2013	9	9/3/13	14	16.00	-	20.00	-	4.23	4.18	-	-	-	-	-	-	-	-	1	-	-	-	5.15
2013	10	10/28/13	19	-	20.75	-	23.00	0.02	4.18	-	-	-	-	-	-	-	-	-	1	-	-	5.02
2013	11	11/21/13	18	-	49.00	-	40.00	-	4.18	-	-	-	-	-	-	-	-	-	-	1	-	5.10
2013	12	12/9/13	19	-	55.50	-	37.50	-	4.18	-	-	-	-	-	-	-	-	-	-	-	1	5.16
2013	12	12/19/13	18	-	35.00	-	39.00	-	4.18	-	-	-	-	-	-	-	-	-	-	-	1	5.14
2013	12	12/19/13	19	-	35.00	-	40.00	-	4.18	-	-	-	-	-	-	-	-	-	-	-	1	5.14
2014	1	1/5/14	18	-	58.00	-	50.50	-	4.19	1	-	-	-	-	-	-	-	-	-	-	-	5.15
2014	1	1/5/14	19	-	58.00	-	54.00	-	4.19	1	-	-	-	-	-	-	-	-	-	-	-	5.15
2014	2	2/4/14	18	-	55.25	-	50.50	-	4.19	-	1	-	-	-	-	-	-	-	-	-	-	5.14
2014	2	2/4/14	19	-	55.25	-	51.00	-	4.19	-	1	-	-	-	-	-	-	-	-	-	-	5.14
2014	2	2/4/14	20	-	55.25	-	52.50	-	4.19	-	1	-	-	-	-	-	-	-	-	-	-	5.14
2014	3	3/1/14	19	-	49.00	-	47.00	-	4.19	-	-	1	-	-	-	-	-	-	-	-	-	5.09

2014	4	4/13/14	21	-	30.00	-	31.50	-	4.19	-	-	-	1	-	-	-	-	-	-	-	-	5.02
2014	4	4/14/14	10	-	36.50	-	34.00	-	4.19	-	-	-	1	-	-	-	-	-	-	-	-	5.02
2014	4	4/29/14	21	-	26.50	-	15.50	-	4.19	-	-	-	1	-	-	-	-	-	-	-	-	5.00
2014	5	5/29/14	15	4.00	-	8.00	-	0.43	4.19	-	-	-	-	1	-	-	-	-	-	-	-	5.01
2014	6	6/17/14	16	5.50	-	10.00	-	2.56	4.19	-	-	-	-	-	1	-	-	-	-	-	-	5.09
2014	6	6/20/14	17	6.00	-	12.00	-	2.56	4.19	-	-	-	-	-	1	-	-	-	-	-	-	5.09
2014	6	6/26/14	17	7.50	-	10.00	-	2.56	4.19	-	-	-	-	-	1	-	-	-	-	-	-	5.10
2014	7	7/21/14	16	16.00	-	18.00	-	8.93	4.19	-	-	-	-	-	-	1	-	-	-	-	-	5.22
2014	7	7/21/14	17	16.00	-	19.00	-	8.93	4.19	-	-	-	-	-	-	1	-	-	-	-	-	5.22
2014	7	7/22/14	15	13.50	-	12.00	-	8.93	4.19	-	-	-	-	-	-	1	-	-	-	-	-	5.20
2014	8	8/13/14	17	13.50	-	15.00	-	6.77	4.19	-	-	-	-	-	-	-	1	-	-	-	-	5.17
2014	9	9/3/14	15	10.00	-	16.00	-	3.44	4.19	-	-	-	-	-	-	-	-	1	-	-	-	5.12
2014	9	9/3/14	16	10.00	-	19.00	-	3.44	4.19	-	-	-	-	-	-	-	-	1	-	-	-	5.12
2014	9	9/3/14	17	10.00	-	18.50	-	3.44	4.19	-	-	-	-	-	-	-	-	1	-	-	-	5.12
2014	9	9/3/14	18	10.00	-	19.00	-	3.44	4.19	-	-	-	-	-	-	-	-	1	-	-	-	5.12
2014	10	10/7/14	14	3.00	-	-	-	0.19	4.19	-	-	-	-	-	-	-	-	-	1	-	-	5.01
2014	10	10/7/14	15	3.00	-	0.50	-	0.19	4.19	-	-	-	-	-	-	-	-	-	1	-	-	5.01
2014	10	10/7/14	17	3.00	-	4.00	-	0.19	4.19	-	-	-	-	-	-	-	-	-	1	-	-	5.02
2014	10	10/8/14	14	-	2.00	-	-	0.19	4.19	-	-	-	-	-	-	-	-	-	1	-	-	5.00
2014	10	10/20/14	20	-	6.00	-	-	0.19	4.19	-	-	-	-	-	-	-	-	-	1	-	-	5.00
2014	10	10/23/14	14	-	7.00	-	-	0.19	4.19	-	-	-	-	-	-	-	-	-	1	-	-	5.00
2014	10	10/27/14	20	-	20.00	-	8.00	0.19	4.19	-	-	-	-	-	-	-	-	-	1	-	-	5.01
2014	11	11/12/14	18	-	65.50	-	50.00	-	4.19	-	-	-	-	-	-	-	-	-	-	1	-	5.13
2014	11	11/13/14	18	-	62.50	-	43.00	-	4.19	-	-	-	-	-	-	-	-	-	-	1	-	5.12
2014	11	11/24/14	18	-	35.50	-	22.50	-	4.19	-	-	-	-	-	-	-	-	-	-	1	-	5.09
2014	12	12/29/14	18	-	54.00	-	47.00	-	4.19	-	-	-	-	-	-	-	-	-	-	-	1	5.17
2014	12	12/30/14	19	-	71.00	-	60.00	-	4.19	-	-	-	-	-	-	-	-	-	-	-	1	5.19
2014	12	12/30/14	20	-	71.00	-	61.00	-	4.19	-	-	-	-	-	-	-	-	-	-	-	1	5.19
2015	1	1/3/15	19	-	44.50	-	48.00	-	4.21	1	-	-	-	-	-	-	-	-	-	-	-	5.15
2015	1	1/7/15	19	-	32.50	-	31.00	-	4.21	1	-	-	-	-	-	-	-	-	-	-	-	5.13
2015	2	2/4/15	19	-	32.25	-	29.00	-	4.21	-	1	-	-	-	-	-	-	-	-	-	-	5.12
2015	2	2/16/15	19	-	38.00	-	28.00	-	4.21	-	1	-	-	-	-	-	-	-	-	-	-	5.12
2015	3	3/3/15	19	-	38.00	-	41.00	0.09	4.21	-	-	1	-	-	-	-	-	-	-	-	-	5.08
2015	4	4/16/15	11	-	28.25	-	18.50	-	4.21	-	-	-	1	-	-	-	-	-	-	-	-	5.01
2015	4	4/16/15	12	-	28.25	-	17.50	-	4.21	-	-	-	1	-	-	-	-	-	-	-	-	5.01

2015	5	5/8/15	11	-	18.25	-	9.00	0.08	4.21	-	-	-	-	1	-	-	-	-	-	-	-	5.00
2015	5	5/8/15	12	-	18.25	-	9.00	0.08	4.21	-	-	-	-	1	-	-	-	-	-	-	-	5.00
2015	5	5/8/15	13	-	18.25	-	9.00	0.08	4.21	-	-	-	-	1	-	-	-	-	-	-	-	5.00
2015	5	5/9/15	21	-	26.50	-	25.50	0.08	4.21	-	-	-	-	1	-	-	-	-	-	-	-	5.01
2015	5	5/11/15	11	-	20.50	-	7.00	0.08	4.21	-	-	-	-	1	-	-	-	-	-	-	-	5.00
2015	5	5/11/15	12	-	20.50	-	6.00	0.08	4.21	-	-	-	-	1	-	-	-	-	-	-	-	5.00
2015	5	5/11/15	14	-	20.50	-	1.00	0.08	4.21	-	-	-	-	1	-	-	-	-	-	-	-	4.99
2015	6	6/19/15	14	14.50	-	17.00	-	5.56	4.21	-	-	-	-	-	1	-	-	-	-	-	-	5.17
2015	6	6/19/15	16	14.50	-	17.00	-	5.56	4.21	-	-	-	-	-	1	-	-	-	-	-	-	5.17
2015	6	6/29/15	14	11.00	-	10.00	-	5.56	4.21	-	-	-	-	-	1	-	-	-	-	-	-	5.14
2015	6	6/29/15	17	11.00	-	13.00	-	5.56	4.21	-	-	-	-	-	1	-	-	-	-	-	-	5.15
2015	6	6/30/15	14	12.25	-	14.00	-	5.56	4.21	-	-	-	-	-	1	-	-	-	-	-	-	5.16
2015	7	7/27/15	15	13.00	-	20.00	-	8.10	4.21	-	-	-	-	-	-	1	-	-	-	-	-	5.21
2015	7	7/27/15	16	13.00	-	19.00	-	8.10	4.21	-	-	-	-	-	-	1	-	-	-	-	-	5.21
2015	7	7/27/15	17	13.00	-	18.50	-	8.10	4.21	-	-	-	-	-	-	1	-	-	-	-	-	5.21
2015	7	7/27/15	18	13.00	-	18.00	-	8.10	4.21	-	-	-	-	-	-	1	-	-	-	-	-	5.21
2015	8	8/14/15	14	13.50	-	18.00	-	8.76	4.21	-	-	-	-	-	-	-	1	-	-	-	-	5.20
2015	8	8/14/15	15	13.50	-	19.00	-	8.76	4.21	-	-	-	-	-	-	-	1	-	-	-	-	5.20
2015	8	8/14/15	16	13.50	-	16.00	-	8.76	4.21	-	-	-	-	-	-	-	1	-	-	-	-	5.19
2015	9	9/2/15	16	14.50	-	18.00	-	5.38	4.21	-	-	-	-	-	-	-	-	1	-	-	-	5.17
2015	9	9/2/15	17	14.50	-	13.00	-	5.38	4.21	-	-	-	-	-	-	-	-	1	-	-	-	5.16
2015	9	9/2/15	18	14.50	-	12.00	-	5.38	4.21	-	-	-	-	-	-	-	-	1	-	-	-	5.15
2015	10	10/21/15	19	-	16.75	-	6.00	0.65	4.21	-	-	-	-	-	-	-	-	-	1	-	-	5.02
2015	10	10/22/15	19	-	18.75	-	10.00	0.65	4.21	-	-	-	-	-	-	-	-	-	1	-	-	5.03
2015	10	10/28/15	19	-	17.50	-	3.00	0.65	4.21	-	-	-	-	-	-	-	-	-	1	-	-	5.02
2015	11	11/30/15	18	-	41.00	-	32.00	-	4.21	-	-	-	-	-	-	-	-	-	-	1	-	5.11
2015	11	11/30/15	19	-	41.00	-	33.00	-	4.21	-	-	-	-	-	-	-	-	-	-	1	-	5.11
2015	12	12/28/15	18	-	45.50	-	37.00	-	4.21	-	-	-	-	-	-	-	-	-	-	-	1	5.16
2015	12	12/30/15	19	-	44.00	-	38.00	-	4.21	-	-	-	-	-	-	-	-	-	-	-	1	5.16
2015	12	12/31/15	18	-	48.50	-	42.00	-	4.21	-	-	-	-	-	-	-	-	-	-	-	1	5.17
2016	1	1/7/16	18	-	29.00	-	19.00	-	4.21	1	-	-	-	-	-	-	-	-	-	-	-	5.12
2016	1	1/8/16	18	-	41.50	-	36.00	-	4.21	1	-	-	-	-	-	-	-	-	-	-	-	5.14
2016	2	2/1/16	18	-	38.25	-	28.00	-	4.21	-	1	-	-	-	-	-	-	-	-	-	-	5.12
2016	3	3/7/16	18	-	22.00	-	15.00	-	4.21	-	-	1	-	-	-	-	-	-	-	-	-	5.06
2016	3	3/17/16	19	-	31.00	-	23.00	-	4.21	-	-	1	-	-	-	-	-	-	-	-	-	5.07

2016	3	3/18/16	9	-	37.50	-	29.00	-	4.21	-	-	1	-	-	-	-	-	-	-	-	-	5.08
2016	3	3/18/16	10	-	37.50	-	29.00	-	4.21	-	-	1	-	-	-	-	-	-	-	-	-	5.08
2016	4	4/1/16	12	-	28.00	-	15.50	-	4.21	-	-	-	1	-	-	-	-	-	-	-	-	5.02
2016	4	4/28/16	13	-	27.25	-	17.50	-	4.21	-	-	-	1	-	-	-	-	-	-	-	-	5.02
2016	4	4/29/16	9	-	28.00	-	18.00	-	4.21	-	-	-	1	-	-	-	-	-	-	-	-	5.02
2016	4	4/29/16	10	-	28.00	-	17.50	-	4.21	-	-	-	1	-	-	-	-	-	-	-	-	5.02
2016	4	4/29/16	12	-	28.00	-	16.50	-	4.21	-	-	-	1	-	-	-	-	-	-	-	-	5.02
2016	5	5/16/16	11	-	23.50	-	10.50	0.11	4.21	-	-	-	-	1	-	-	-	-	-	-	-	5.01
2016	6	6/21/16	14	15.50	-	23.00	-	7.16	4.21	-	-	-	-	-	1	-	-	-	-	-	-	5.21
2016	6	6/21/16	16	15.50	-	21.00	-	7.16	4.21	-	-	-	-	-	1	-	-	-	-	-	-	5.20
2016	7	7/21/16	15	15.50	-	21.00	-	11.39	4.21	-	-	-	-	-	-	1	-	-	-	-	-	5.26
2016	8	8/2/16	16	12.50	-	13.00	-	6.83	4.21	-	-	-	-	-	-	-	1	-	-	-	-	5.17
2016	8	8/9/16	16	12.50	-	20.00	-	6.83	4.21	-	-	-	-	-	-	-	1	-	-	-	-	5.19
2016	9	9/19/16	13	11.75	-	14.00	-	3.24	4.21	-	-	-	-	-	-	-	-	1	-	-	-	5.13
2016	10	10/3/16	12	-	2.00	-	-	0.43	4.21	-	-	-	-	-	-	-	-	-	1	-	-	5.01
2016	10	10/5/16	11	-	14.50	-	-	0.43	4.21	-	-	-	-	-	-	-	-	-	1	-	-	5.02
2016	11	11/29/16	18	-	34.50	-	24.00	-	4.21	-	-	-	-	-	-	-	-	-	-	1	-	5.10
2016	11	11/29/16	19	-	34.50	-	25.00	-	4.21	-	-	-	-	-	-	-	-	-	-	1	-	5.10
2016	12	12/7/16	18	-	63.25	-	57.00	-	4.21	-	-	-	-	-	-	-	-	-	-	-	1	5.20
2016	12	12/7/16	20	-	63.25	-	61.00	-	4.21	-	-	-	-	-	-	-	-	-	-	-	1	5.20
2017	1	1/4/17	18	-	54.50	-	48.50	-	4.22	1	-	-	-	-	-	-	-	-	-	-	-	5.16
2017	1	1/4/17	19	-	54.50	-	49.00	-	4.22	1	-	-	-	-	-	-	-	-	-	-	-	5.16
2017	2	2/2/17	19	-	46.75	-	33.00	-	4.22	-	1	-	-	-	-	-	-	-	-	-	-	5.14
2017	3	3/6/17	19	-	27.50	-	26.00	-	4.22	-	-	1	-	-	-	-	-	-	-	-	-	5.07
2017	3	3/6/17	20	-	27.50	-	27.00	-	4.22	-	-	1	-	-	-	-	-	-	-	-	-	5.08
2017	4	4/4/17	10	-	27.75	-	19.00	-	4.22	-	-	-	1	-	-	-	-	-	-	-	-	5.02
2017	4	4/4/17	11	-	27.75	-	16.50	-	4.22	-	-	-	1	-	-	-	-	-	-	-	-	5.02
2017	4	4/4/17	12	-	27.75	-	15.00	-	4.22	-	-	-	1	-	-	-	-	-	-	-	-	5.02
2017	4	4/4/17	21	-	27.75	-	19.00	-	4.22	-	-	-	1	-	-	-	-	-	-	-	-	5.02
2017	5	5/18/17	15	-	25.25	-	19.50	0.21	4.22	-	-	-	-	1	-	-	-	-	-	-	-	5.02
2017	5	5/18/17	16	-	25.25	-	19.00	0.21	4.22	-	-	-	-	1	-	-	-	-	-	-	-	5.02
2017	5	5/31/17	14	0.50	-	7.00	-	0.21	4.22	-	-	-	-	1	-	-	-	-	-	-	-	5.00
2017	6	6/21/17	16	16.00	-	15.00	-	4.52	4.22	-	-	-	-	-	1	-	-	-	-	-	-	5.18
2017	6	6/21/17	18	16.00	-	19.00	-	4.52	4.22	-	-	-	-	-	1	-	-	-	-	-	-	5.19
2017	7	7/19/17	15	20.00	-	27.00	-	11.93	4.22	-	-	-	-	-	-	1	-	-	-	-	-	5.30

2017	7	7/19/17	16	20.00	-	24.00	-	11.93	4.22	-	-	-	-	-	-	1	-	-	-	-	-	5.29
2017	7	7/19/17	17	20.00	-	20.50	-	11.93	4.22	-	-	-	-	-	-	1	-	-	-	-	-	5.29
2017	7	7/24/17	14	15.00	-	23.00	-	11.93	4.22	-	-	-	-	-	-	1	-	-	-	-	-	5.27
2017	8	8/28/17	16	9.50	-	16.00	-	6.94	4.22	-	-	-	-	-	-	-	1	-	-	-	-	5.17
2017	8	8/28/17	17	9.50	-	16.00	-	6.94	4.22	-	-	-	-	-	-	-	1	-	-	-	-	5.17
2017	9	9/12/17	17	11.50	-	17.00	-	3.99	4.22	-	-	-	-	-	-	-	-	1	-	-	-	5.15
2017	10	10/30/17	11	-	31.75	-	25.00	0.11	4.22	-	-	-	-	-	-	-	-	-	1	-	-	5.05
2017	11	11/7/17	18	-	37.00	-	27.00	-	4.22	-	-	-	-	-	-	-	-	-	-	1	-	5.11
2017	11	11/28/17	18	-	24.00	-	15.50	-	4.22	-	-	-	-	-	-	-	-	-	-	1	-	5.09
2017	12	12/26/17	18	-	55.50	-	47.00	-	4.22	-	-	-	-	-	-	-	-	-	-	-	1	5.19
2017	12	12/26/17	19	-	55.50	-	49.00	-	4.22	-	-	-	-	-	-	-	-	-	-	-	1	5.19
2018	1	1/15/18	18	-	49.75	-	42.50	-	4.24	1	-	-	-	-	-	-	-	-	-	-	-	5.17
2018	1	1/15/18	20	-	49.75	-	46.00	-	4.24	1	-	-	-	-	-	-	-	-	-	-	-	5.17
2018	2	2/12/18	18	-	48.75	-	36.50	-	4.24	-	1	-	-	-	-	-	-	-	-	-	-	5.15
2018	2	2/19/18	18	-	58.50	-	49.50	-	4.24	-	1	-	-	-	-	-	-	-	-	-	-	5.17
2018	2	2/19/18	19	-	58.50	-	51.00	-	4.24	-	1	-	-	-	-	-	-	-	-	-	-	5.17
2018	2	2/19/18	20	-	58.50	-	51.00	-	4.24	-	1	-	-	-	-	-	-	-	-	-	-	5.17
2018	3	3/5/18	19	-	33.25	-	25.00	-	4.24	-	-	1	-	-	-	-	-	-	-	-	-	5.09
2018	4	4/13/18	11	-	28.25	-	21.50	-	4.24	-	-	-	1	-	-	-	-	-	-	-	-	5.04
2018	4	4/24/18	10	-	26.75	-	20.00	-	4.24	-	-	-	1	-	-	-	-	-	-	-	-	5.03
2018	4	4/24/18	11	-	26.75	-	18.00	-	4.24	-	-	-	1	-	-	-	-	-	-	-	-	5.03
2018	5	5/17/18	15	5.00	-	8.00	-	0.82	4.24	-	-	-	-	1	-	-	-	-	-	-	-	5.04
2018	5	5/17/18	16	5.00	-	6.00	-	0.82	4.24	-	-	-	-	1	-	-	-	-	-	-	-	5.04
2018	5	5/17/18	17	5.00	-	8.00	-	0.82	4.24	-	-	-	-	1	-	-	-	-	-	-	-	5.04
2018	5	5/25/18	16	5.50	-	11.00	-	0.82	4.24	-	-	-	-	1	-	-	-	-	-	-	-	5.05
2018	6	6/28/18	14	21.00	-	26.00	-	6.56	4.24	-	-	-	-	-	1	-	-	-	-	-	-	5.25
2018	6	6/28/18	15	21.00	-	22.00	-	6.56	4.24	-	-	-	-	-	1	-	-	-	-	-	-	5.24
2018	6	6/28/18	17	21.00	-	28.00	-	6.56	4.24	-	-	-	-	-	1	-	-	-	-	-	-	5.26
2018	7	7/10/18	17	14.50	-	23.00	-	10.02	4.24	-	-	-	-	-	-	1	-	-	-	-	-	5.26
2018	8	8/9/18	18	9.00	-	12.00	-	6.72	4.24	-	-	-	-	-	-	-	1	-	-	-	-	5.17
2018	8	8/16/18	16	9.00	-	15.00	-	6.72	4.24	-	-	-	-	-	-	-	1	-	-	-	-	5.17
2018	8	8/16/18	17	9.00	-	14.00	-	6.72	4.24	-	-	-	-	-	-	-	1	-	-	-	-	5.17
2018	8	8/16/18	18	9.00	-	10.00	-	6.72	4.24	-	-	-	-	-	-	-	1	-	-	-	-	5.16
2018	9	9/12/18	17	11.00	-	16.00	-	4.87	4.24	-	-	-	-	-	-	-	-	1	-	-	-	5.16
2018	9	9/12/18	18	11.00	-	15.00	-	4.87	4.24	-	-	-	-	-	-	-	-	1	-	-	-	5.16

2018	9	9/13/18	17	12.00	-	18.00	-	4.87	4.24	-	-	-	-	-	-	-	-	1	-	-	-	5.17
2018	9	9/18/18	16	10.25	-	16.00	-	4.87	4.24	-	-	-	-	-	-	-	-	1	-	-	-	5.16
2018	9	9/18/18	17	10.25	-	13.00	-	4.87	4.24	-	-	-	-	-	-	-	-	1	-	-	-	5.15
2018	9	9/18/18	18	10.25	-	10.00	-	4.87	4.24	-	-	-	-	-	-	-	-	1	-	-	-	5.15
2018	10	10/10/18	12	-	31.50	-	21.00	0.07	4.24	-	-	-	-	-	-	-	-	-	1	-	-	5.06
2018	10	10/10/18	19	-	31.50	-	20.00	0.07	4.24	-	-	-	-	-	-	-	-	-	1	-	-	5.06
2018	10	10/10/18	20	-	31.50	-	20.00	0.07	4.24	-	-	-	-	-	-	-	-	-	1	-	-	5.06
2018	10	10/15/18	9	-	34.50	-	27.00	0.07	4.24	-	-	-	-	-	-	-	-	-	1	-	-	5.06
2018	11	11/12/18	18	-	41.50	-	28.50	-	4.24	-	-	-	-	-	-	-	-	-	-	1	-	5.12
2018	11	11/12/18	19	-	41.50	-	28.00	-	4.24	-	-	-	-	-	-	-	-	-	-	1	-	5.12
2018	11	11/17/18	18	-	38.25	-	36.00	-	4.24	-	-	-	-	-	-	-	-	-	-	1	-	5.13
2018	12	12/31/18	18	-	46.75	-	48.00	-	4.24	-	-	-	-	-	-	-	-	-	-	-	1	5.19
2019	1	1/28/19	19	-	40.25	-	32.00	-	4.25	1	-	-	-	-	-	-	-	-	-	-	-	5.16
2019	2	2/6/19	19	-	50.75	-	52.00	-	4.25	-	1	-	-	-	-	-	-	-	-	-	-	5.17
2019	2	2/6/19	20	-	50.75	-	52.00	-	4.25	-	1	-	-	-	-	-	-	-	-	-	-	5.17
2019	3	3/3/19	19	-	65.00	-	52.00	-	4.25	-	-	1	-	-	-	-	-	-	-	-	-	5.14
2019	3	3/3/19	20	-	65.00	-	56.00	-	4.25	-	-	1	-	-	-	-	-	-	-	-	-	5.14
2019	4	4/11/19	8	-	38.25	-	31.00	-	4.25	-	-	-	1	-	-	-	-	-	-	-	-	5.06
2019	4	4/11/19	11	-	38.25	-	24.50	-	4.25	-	-	-	1	-	-	-	-	-	-	-	-	5.05
2019	4	4/11/19	20	-	38.25	-	27.00	-	4.25	-	-	-	1	-	-	-	-	-	-	-	-	5.06
2019	5	5/20/19	10	-	26.50	-	17.00	0.11	4.25	-	-	-	-	1	-	-	-	-	-	-	-	5.04
2019	5	5/20/19	12	-	26.50	-	14.00	0.11	4.25	-	-	-	-	1	-	-	-	-	-	-	-	5.04
2019	5	5/20/19	14	-	26.50	-	15.00	0.11	4.25	-	-	-	-	1	-	-	-	-	-	-	-	5.04
2019	6	6/28/19	15	12.50	-	19.00	-	2.88	4.25	-	-	-	-	-	1	-	-	-	-	-	-	5.18
2019	6	6/28/19	16	12.50	-	18.00	-	2.88	4.25	-	-	-	-	-	1	-	-	-	-	-	-	5.18
2019	7	7/19/19	15	18.50	-	24.00	-	9.94	4.25	-	-	-	-	-	-	1	-	-	-	-	-	5.29
2019	7	7/19/19	16	18.50	-	24.00	-	9.94	4.25	-	-	-	-	-	-	1	-	-	-	-	-	5.29
2019	8	8/6/19	16	13.50	-	21.00	-	10.10	4.25	-	-	-	-	-	-	-	1	-	-	-	-	5.24
2019	9	9/5/19	15	17.25	-	18.00	-	5.08	4.25	-	-	-	-	-	-	-	-	1	-	-	-	5.21
2019	9	9/5/19	16	17.25	-	19.00	-	5.08	4.25	-	-	-	-	-	-	-	-	1	-	-	-	5.21
2019	10	10/30/19	19	-	49.00	-	35.50	-	4.25	-	-	-	-	-	-	-	-	-	1	-	-	5.09
2019	11	11/25/19	18	-	28.50	-	26.00	-	4.25	-	-	-	-	-	-	-	-	-	-	1	-	5.12
2019	11	11/26/19	19	-	48.25	-	39.00	-	4.25	-	-	-	-	-	-	-	-	-	-	1	-	5.14
2019	11	11/27/19	18	-	53.00	-	35.50	-	4.25	-	-	-	-	-	-	-	-	-	-	1	-	5.15
2019	12	12/16/19	18	-	45.00	-	34.00	-	4.25	-	-	-	-	-	-	-	-	-	-	-	1	5.19

2019	12	12/29/19	18	-	43.75	-	33.00	-	4.25	-	-	-	-	-	-	-	-	-	-	-	1	5.19
2020	1			-	47.16	-	39.53	-	4.26	1	-	-	-	-	-	-	-	-	-	-	-	5.18
2020	2			-	48.49	-	40.80	-	4.26	-	1	-	-	-	-	-	-	-	-	-	-	5.17
2020	3			-	37.23	-	30.62	0.01	4.26	-	-	1	-	-	-	-	-	-	-	-	-	5.11
2020	4			-	29.15	-	20.00	0.03	4.26	-	-	-	1	-	-	-	-	-	-	-	-	5.05
2020	5			5.93	-	9.31	-	0.86	4.26	-	-	-	-	1	-	-	-	-	-	-	-	5.07
2020	6			12.99	-	17.05	-	4.85	4.26	-	-	-	-	-	1	-	-	-	-	-	-	5.20
2020	7			15.54	-	20.30	-	10.66	4.26	-	-	-	-	-	-	1	-	-	-	-	-	5.28
2020	8			13.62	-	17.06	-	8.23	4.26	-	-	-	-	-	-	-	1	-	-	-	-	5.23
2020	9			10.14	-	13.18	-	3.17	4.26	-	-	-	-	-	-	-	-	1	-	-	-	5.16
2020	10			-	23.84	-	13.89	0.20	4.26	-	-	-	-	-	-	-	-	-	1	-	-	5.07
2020	11			-	39.63	-	29.60	-	4.26	-	-	-	-	-	-	-	-	-	-	1	-	5.14
2020	12			-	49.03	-	41.47	-	4.26	-	-	-	-	-	-	-	-	-	-	-	1	5.21
2021	1			-	47.16	-	39.53	-	4.28	1	-	-	-	-	-	-	-	-	-	-	-	5.19
2021	2			-	48.49	-	40.80	-	4.28	-	1	-	-	-	-	-	-	-	-	-	-	5.18
2021	3			-	37.23	-	30.62	0.01	4.28	-	-	1	-	-	-	-	-	-	-	-	-	5.12
2021	4			-	29.15	-	20.00	0.03	4.28	-	-	-	1	-	-	-	-	-	-	-	-	5.06
2021	5			5.93	-	9.31	-	0.86	4.28	-	-	-	-	1	-	-	-	-	-	-	-	5.08
2021	6			12.99	-	17.05	-	4.85	4.28	-	-	-	-	-	1	-	-	-	-	-	-	5.21
2021	7			15.54	-	20.30	-	10.66	4.28	-	-	-	-	-	-	1	-	-	-	-	-	5.29
2021	8			13.62	-	17.06	-	8.23	4.28	-	-	-	-	-	-	-	1	-	-	-	-	5.24
2021	9			10.14	-	13.18	-	3.17	4.28	-	-	-	-	-	-	-	-	1	-	-	-	5.17
2021	10			-	23.84	-	13.89	0.20	4.28	-	-	-	-	-	-	-	-	-	1	-	-	5.08
2021	11			-	39.63	-	29.60	-	4.28	-	-	-	-	-	-	-	-	-	-	1	-	5.15
2021	12			-	49.03	-	41.47	-	4.28	-	-	-	-	-	-	-	-	-	-	-	1	5.22
2022	1			-	47.16	-	39.53	-	4.29	1	-	-	-	-	-	-	-	-	-	-	-	5.20
2022	2			-	48.49	-	40.80	-	4.29	-	1	-	-	-	-	-	-	-	-	-	-	5.19
2022	3			-	37.23	-	30.62	0.01	4.29	-	-	1	-	-	-	-	-	-	-	-	-	5.13
2022	4			-	29.15	-	20.00	0.03	4.29	-	-	-	1	-	-	-	-	-	-	-	-	5.07
2022	5			5.93	-	9.31	-	0.86	4.29	-	-	-	-	1	-	-	-	-	-	-	-	5.09
2022	6			12.99	-	17.05	-	4.85	4.29	-	-	-	-	-	1	-	-	-	-	-	-	5.22
2022	7			15.54	-	20.30	-	10.66	4.29	-	-	-	-	-	-	1	-	-	-	-	-	5.30
2022	8			13.62	-	17.06	-	8.23	4.29	-	-	-	-	-	-	-	1	-	-	-	-	5.25
2022	9			10.14	-	13.18	-	3.17	4.29	-	-	-	-	-	-	-	-	1	-	-	-	5.17
2022	10			-	23.84	-	13.89	0.20	4.29	-	-	-	-	-	-	-	-	-	1	-	-	5.08

2022	11			-	39.63	-	29.60	-	4.29	-	-	-	-	-	-	-	-	-	-	1	-	5.16
2022	12			-	49.03	-	41.47	-	4.29	-	-	-	-	-	-	-	-	-	-	-	1	5.23
2023	1			-	47.16	-	39.53	-	4.30	1	-	-	-	-	-	-	-	-	-	-	-	5.21
2023	2			-	48.49	-	40.80	-	4.30	-	1	-	-	-	-	-	-	-	-	-	-	5.20
2023	3			-	37.23	-	30.62	0.01	4.30	-	-	1	-	-	-	-	-	-	-	-	-	5.14
2023	4			-	29.15	-	20.00	0.03	4.30	-	-	-	1	-	-	-	-	-	-	-	-	5.08
2023	5			5.93	-	9.31	-	0.86	4.30	-	-	-	-	1	-	-	-	-	-	-	-	5.10
2023	6			12.99	-	17.05	-	4.85	4.30	-	-	-	-	-	1	-	-	-	-	-	-	5.23
2023	7			15.54	-	20.30	-	10.66	4.30	-	-	-	-	-	-	1	-	-	-	-	-	5.31
2023	8			13.62	-	17.06	-	8.23	4.30	-	-	-	-	-	-	-	1	-	-	-	-	5.26
2023	9			10.14	-	13.18	-	3.17	4.30	-	-	-	-	-	-	-	-	1	-	-	-	5.18
2023	10			-	23.84	-	13.89	0.20	4.30	-	-	-	-	-	-	-	-	-	1	-	-	5.09
2023	11			-	39.63	-	29.60	-	4.30	-	-	-	-	-	-	-	-	-	-	1	-	5.17
2023	12			-	49.03	-	41.47	-	4.30	-	-	-	-	-	-	-	-	-	-	-	1	5.23
2024	1			-	47.16	-	39.53	-	4.31	1	-	-	-	-	-	-	-	-	-	-	-	5.22
2024	2			-	48.49	-	40.80	-	4.31	-	1	-	-	-	-	-	-	-	-	-	-	5.21
2024	3			-	37.23	-	30.62	0.01	4.31	-	-	1	-	-	-	-	-	-	-	-	-	5.15
2024	4			-	29.15	-	20.00	0.03	4.31	-	-	-	1	-	-	-	-	-	-	-	-	5.09
2024	5			5.93	-	9.31	-	0.86	4.31	-	-	-	-	1	-	-	-	-	-	-	-	5.10
2024	6			12.99	-	17.05	-	4.85	4.31	-	-	-	-	-	1	-	-	-	-	-	-	5.23
2024	7			15.54	-	20.30	-	10.66	4.31	-	-	-	-	-	-	1	-	-	-	-	-	5.32
2024	8			13.62	-	17.06	-	8.23	4.31	-	-	-	-	-	-	-	1	-	-	-	-	5.26
2024	9			10.14	-	13.18	-	3.17	4.31	-	-	-	-	-	-	-	-	1	-	-	-	5.19
2024	10			-	23.84	-	13.89	0.20	4.31	-	-	-	-	-	-	-	-	-	1	-	-	5.10
2024	11			-	39.63	-	29.60	-	4.31	-	-	-	-	-	-	-	-	-	-	1	-	5.18
2024	12			-	49.03	-	41.47	-	4.31	-	-	-	-	-	-	-	-	-	-	-	1	5.24
2025	1			-	47.16	-	39.53	-	4.33	1	-	-	-	-	-	-	-	-	-	-	-	5.23
2025	2			-	48.49	-	40.80	-	4.33	-	1	-	-	-	-	-	-	-	-	-	-	5.22
2025	3			-	37.23	-	30.62	0.01	4.33	-	-	1	-	-	-	-	-	-	-	-	-	5.16
2025	4			-	29.15	-	20.00	0.03	4.33	-	-	-	1	-	-	-	-	-	-	-	-	5.10
2025	5			5.93	-	9.31	-	0.86	4.33	-	-	-	-	1	-	-	-	-	-	-	-	5.11
2025	6			12.99	-	17.05	-	4.85	4.33	-	-	-	-	-	1	-	-	-	-	-	-	5.24
2025	7			15.54	-	20.30	-	10.66	4.33	-	-	-	-	-	-	1	-	-	-	-	-	5.33
2025	8			13.62	-	17.06	-	8.23	4.33	-	-	-	-	-	-	-	1	-	-	-	-	5.27
2025	9			10.14	-	13.18	-	3.17	4.33	-	-	-	-	-	-	-	-	1	-	-	-	5.20

2025	10			-	23.84	-	13.89	0.20	4.33	-	-	-	-	-	-	-	-	-	1	-	-	5.11
2025	11			-	39.63	-	29.60	-	4.33	-	-	-	-	-	-	-	-	-	-	1	-	5.18
2025	12			-	49.03	-	41.47	-	4.33	-	-	-	-	-	-	-	-	-	-	-	1	5.25
2026	1			-	47.16	-	39.53	-	4.34	1	-	-	-	-	-	-	-	-	-	-	-	5.23
2026	2			-	48.49	-	40.80	-	4.34	-	1	-	-	-	-	-	-	-	-	-	-	5.23
2026	3			-	37.23	-	30.62	0.01	4.34	-	-	1	-	-	-	-	-	-	-	-	-	5.17
2026	4			-	29.15	-	20.00	0.03	4.34	-	-	-	1	-	-	-	-	-	-	-	-	5.11
2026	5			5.93	-	9.31	-	0.86	4.34	-	-	-	-	1	-	-	-	-	-	-	-	5.12
2026	6			12.99	-	17.05	-	4.85	4.34	-	-	-	-	-	1	-	-	-	-	-	-	5.25
2026	7			15.54	-	20.30	-	10.66	4.34	-	-	-	-	-	-	1	-	-	-	-	-	5.34
2026	8			13.62	-	17.06	-	8.23	4.34	-	-	-	-	-	-	-	1	-	-	-	-	5.28
2026	9			10.14	-	13.18	-	3.17	4.34	-	-	-	-	-	-	-	-	1	-	-	-	5.21
2026	10			-	23.84	-	13.89	0.20	4.34	-	-	-	-	-	-	-	-	-	1	-	-	5.12
2026	11			-	39.63	-	29.60	-	4.34	-	-	-	-	-	-	-	-	-	-	1	-	5.19
2026	12			-	49.03	-	41.47	-	4.34	-	-	-	-	-	-	-	-	-	-	-	1	5.26
2027	1			-	47.16	-	39.53	-	4.35	1	-	-	-	-	-	-	-	-	-	-	-	5.24
2027	2			-	48.49	-	40.80	-	4.35	-	1	-	-	-	-	-	-	-	-	-	-	5.23
2027	3			-	37.23	-	30.62	0.01	4.35	-	-	1	-	-	-	-	-	-	-	-	-	5.17
2027	4			-	29.15	-	20.00	0.03	4.35	-	-	-	1	-	-	-	-	-	-	-	-	5.11
2027	5			5.93	-	9.31	-	0.86	4.35	-	-	-	-	1	-	-	-	-	-	-	-	5.13
2027	6			12.99	-	17.05	-	4.85	4.35	-	-	-	-	-	1	-	-	-	-	-	-	5.26
2027	7			15.54	-	20.30	-	10.66	4.35	-	-	-	-	-	-	1	-	-	-	-	-	5.34
2027	8			13.62	-	17.06	-	8.23	4.35	-	-	-	-	-	-	-	1	-	-	-	-	5.29
2027	9			10.14	-	13.18	-	3.17	4.35	-	-	-	-	-	-	-	-	1	-	-	-	5.22
2027	10			-	23.84	-	13.89	0.20	4.35	-	-	-	-	-	-	-	-	-	1	-	-	5.13
2027	11			-	39.63	-	29.60	-	4.35	-	-	-	-	-	-	-	-	-	-	1	-	5.20
2027	12			-	49.03	-	41.47	-	4.35	-	-	-	-	-	-	-	-	-	-	-	1	5.27
2028	1			-	47.16	-	39.53	-	4.36	1	-	-	-	-	-	-	-	-	-	-	-	5.25
2028	2			-	48.49	-	40.80	-	4.36	-	1	-	-	-	-	-	-	-	-	-	-	5.24
2028	3			-	37.23	-	30.62	0.01	4.36	-	-	1	-	-	-	-	-	-	-	-	-	5.18
2028	4			-	29.15	-	20.00	0.03	4.36	-	-	-	1	-	-	-	-	-	-	-	-	5.12
2028	5			5.93	-	9.31	-	0.86	4.36	-	-	-	-	1	-	-	-	-	-	-	-	5.14
2028	6			12.99	-	17.05	-	4.85	4.36	-	-	-	-	-	1	-	-	-	-	-	-	5.27
2028	7			15.54	-	20.30	-	10.66	4.36	-	-	-	-	-	-	1	-	-	-	-	-	5.35
2028	8			13.62	-	17.06	-	8.23	4.36	-	-	-	-	-	-	-	1	-	-	-	-	5.30

2028	9			10.14	-	13.18	-	3.17	4.36	-	-	-	-	-	-	-	-	1	-	-	-	5.22
2028	10			-	23.84	-	13.89	0.20	4.36	-	-	-	-	-	-	-	-	-	1	-	-	5.13
2028	11			-	39.63	-	29.60	-	4.36	-	-	-	-	-	-	-	-	-	-	1	-	5.21
2028	12			-	49.03	-	41.47	-	4.36	-	-	-	-	-	-	-	-	-	-	-	1	5.28
2029	1			-	47.16	-	39.53	-	4.37	1	-	-	-	-	-	-	-	-	-	-	-	5.26
2029	2			-	48.49	-	40.80	-	4.37	-	1	-	-	-	-	-	-	-	-	-	-	5.25
2029	3			-	37.23	-	30.62	0.01	4.37	-	-	1	-	-	-	-	-	-	-	-	-	5.19
2029	4			-	29.15	-	20.00	0.03	4.37	-	-	-	1	-	-	-	-	-	-	-	-	5.13
2029	5			5.93	-	9.31	-	0.86	4.37	-	-	-	-	1	-	-	-	-	-	-	-	5.14
2029	6			12.99	-	17.05	-	4.85	4.37	-	-	-	-	-	1	-	-	-	-	-	-	5.27
2029	7			15.54	-	20.30	-	10.66	4.37	-	-	-	-	-	-	1	-	-	-	-	-	5.36
2029	8			13.62	-	17.06	-	8.23	4.37	-	-	-	-	-	-	-	1	-	-	-	-	5.31
2029	9			10.14	-	13.18	-	3.17	4.37	-	-	-	-	-	-	-	-	1	-	-	-	5.23
2029	10			-	23.84	-	13.89	0.20	4.37	-	-	-	-	-	-	-	-	-	1	-	-	5.14
2029	11			-	39.63	-	29.60	-	4.37	-	-	-	-	-	-	-	-	-	-	1	-	5.22
2029	12			-	49.03	-	41.47	-	4.37	-	-	-	-	-	-	-	-	-	-	-	1	5.28
2030	1			-	47.16	-	39.53	-	4.39	1	-	-	-	-	-	-	-	-	-	-	-	5.27
2030	2			-	48.49	-	40.80	-	4.39	-	1	-	-	-	-	-	-	-	-	-	-	5.26
2030	3			-	37.23	-	30.62	0.01	4.39	-	-	1	-	-	-	-	-	-	-	-	-	5.20
2030	4			-	29.15	-	20.00	0.03	4.39	-	-	-	1	-	-	-	-	-	-	-	-	5.14
2030	5			5.93	-	9.31	-	0.86	4.39	-	-	-	-	1	-	-	-	-	-	-	-	5.15
2030	6			12.99	-	17.05	-	4.85	4.39	-	-	-	-	-	1	-	-	-	-	-	-	5.28
2030	7			15.54	-	20.30	-	10.66	4.39	-	-	-	-	-	-	1	-	-	-	-	-	5.37
2030	8			13.62	-	17.06	-	8.23	4.39	-	-	-	-	-	-	-	1	-	-	-	-	5.31
2030	9			10.14	-	13.18	-	3.17	4.39	-	-	-	-	-	-	-	-	1	-	-	-	5.24
2030	10			-	23.84	-	13.89	0.20	4.39	-	-	-	-	-	-	-	-	-	1	-	-	5.15
2030	11			-	39.63	-	29.60	-	4.39	-	-	-	-	-	-	-	-	-	-	1	-	5.22
2030	12			-	49.03	-	41.47	-	4.39	-	-	-	-	-	-	-	-	-	-	-	1	5.29
2031	1			-	47.16	-	39.53	-	4.40	1	-	-	-	-	-	-	-	-	-	-	-	5.27
2031	2			-	48.49	-	40.80	-	4.40	-	1	-	-	-	-	-	-	-	-	-	-	5.26
2031	3			-	37.23	-	30.62	0.01	4.40	-	-	1	-	-	-	-	-	-	-	-	-	5.20
2031	4			-	29.15	-	20.00	0.03	4.40	-	-	-	1	-	-	-	-	-	-	-	-	5.14
2031	5			5.93	-	9.31	-	0.86	4.40	-	-	-	-	1	-	-	-	-	-	-	-	5.16
2031	6			12.99	-	17.05	-	4.85	4.40	-	-	-	-	-	1	-	-	-	-	-	-	5.29
2031	7			15.54	-	20.30	-	10.66	4.40	-	-	-	-	-	-	1	-	-	-	-	-	5.37

2031	8			13.62	-	17.06	-	8.23	4.40	-	-	-	-	-	-	-	1	-	-	-	-	5.32
2031	9			10.14	-	13.18	-	3.17	4.40	-	-	-	-	-	-	-	-	1	-	-	-	5.25
2031	10			-	23.84	-	13.89	0.20	4.40	-	-	-	-	-	-	-	-	-	1	-	-	5.16
2031	11			-	39.63	-	29.60	-	4.40	-	-	-	-	-	-	-	-	-	-	1	-	5.23
2031	12			-	49.03	-	41.47	-	4.40	-	-	-	-	-	-	-	-	-	-	-	1	5.30
2032	1			-	47.16	-	39.53	-	4.41	1	-	-	-	-	-	-	-	-	-	-	-	5.28
2032	2			-	48.49	-	40.80	-	4.41	-	1	-	-	-	-	-	-	-	-	-	-	5.27
2032	3			-	37.23	-	30.62	0.01	4.41	-	-	1	-	-	-	-	-	-	-	-	-	5.21
2032	4			-	29.15	-	20.00	0.03	4.41	-	-	-	1	-	-	-	-	-	-	-	-	5.15
2032	5			5.93	-	9.31	-	0.86	4.41	-	-	-	-	1	-	-	-	-	-	-	-	5.17
2032	6			12.99	-	17.05	-	4.85	4.41	-	-	-	-	-	1	-	-	-	-	-	-	5.30
2032	7			15.54	-	20.30	-	10.66	4.41	-	-	-	-	-	-	1	-	-	-	-	-	5.38
2032	8			13.62	-	17.06	-	8.23	4.41	-	-	-	-	-	-	-	1	-	-	-	-	5.33
2032	9			10.14	-	13.18	-	3.17	4.41	-	-	-	-	-	-	-	-	1	-	-	-	5.25
2032	10			-	23.84	-	13.89	0.20	4.41	-	-	-	-	-	-	-	-	-	1	-	-	5.16
2032	11			-	39.63	-	29.60	-	4.41	-	-	-	-	-	-	-	-	-	-	1	-	5.24
2032	12			-	49.03	-	41.47	-	4.41	-	-	-	-	-	-	-	-	-	-	-	1	5.31
2033	1			-	47.16	-	39.53	-	4.42	1	-	-	-	-	-	-	-	-	-	-	-	5.29
2033	2			-	48.49	-	40.80	-	4.42	-	1	-	-	-	-	-	-	-	-	-	-	5.28
2033	3			-	37.23	-	30.62	0.01	4.42	-	-	1	-	-	-	-	-	-	-	-	-	5.22
2033	4			-	29.15	-	20.00	0.03	4.42	-	-	-	1	-	-	-	-	-	-	-	-	5.16
2033	5			5.93	-	9.31	-	0.86	4.42	-	-	-	-	1	-	-	-	-	-	-	-	5.17
2033	6			12.99	-	17.05	-	4.85	4.42	-	-	-	-	-	1	-	-	-	-	-	-	5.30
2033	7			15.54	-	20.30	-	10.66	4.42	-	-	-	-	-	-	1	-	-	-	-	-	5.39
2033	8			13.62	-	17.06	-	8.23	4.42	-	-	-	-	-	-	-	1	-	-	-	-	5.33
2033	9			10.14	-	13.18	-	3.17	4.42	-	-	-	-	-	-	-	-	1	-	-	-	5.26
2033	10			-	23.84	-	13.89	0.20	4.42	-	-	-	-	-	-	-	-	-	1	-	-	5.17
2033	11			-	39.63	-	29.60	-	4.42	-	-	-	-	-	-	-	-	-	-	1	-	5.25
2033	12			-	49.03	-	41.47	-	4.42	-	-	-	-	-	-	-	-	-	-	-	1	5.31
2034	1			-	47.16	-	39.53	-	4.43	1	-	-	-	-	-	-	-	-	-	-	-	5.29
2034	2			-	48.49	-	40.80	-	4.43	-	1	-	-	-	-	-	-	-	-	-	-	5.29
2034	3			-	37.23	-	30.62	0.01	4.43	-	-	1	-	-	-	-	-	-	-	-	-	5.23
2034	4			-	29.15	-	20.00	0.03	4.43	-	-	-	1	-	-	-	-	-	-	-	-	5.17
2034	5			5.93	-	9.31	-	0.86	4.43	-	-	-	-	1	-	-	-	-	-	-	-	5.18
2034	6			12.99	-	17.05	-	4.85	4.43	-	-	-	-	-	1	-	-	-	-	-	-	5.31

2034	7			15.54	-	20.30	-	10.66	4.43	-	-	-	-	-	-	1	-	-	-	-	-	5.40
2034	8			13.62	-	17.06	-	8.23	4.43	-	-	-	-	-	-	-	1	-	-	-	-	5.34
2034	9			10.14	-	13.18	-	3.17	4.43	-	-	-	-	-	-	-	-	1	-	-	-	5.27
2034	10			-	23.84	-	13.89	0.20	4.43	-	-	-	-	-	-	-	-	-	1	-	-	5.18
2034	11			-	39.63	-	29.60	-	4.43	-	-	-	-	-	-	-	-	-	-	1	-	5.25
2034	12			-	49.03	-	41.47	-	4.43	-	-	-	-	-	-	-	-	-	-	-	1	5.32
2035	1			-	47.16	-	39.53	-	4.44	1	-	-	-	-	-	-	-	-	-	-	-	5.30
2035	2			-	48.49	-	40.80	-	4.44	-	1	-	-	-	-	-	-	-	-	-	-	5.29
2035	3			-	37.23	-	30.62	0.01	4.44	-	-	1	-	-	-	-	-	-	-	-	-	5.23
2035	4			-	29.15	-	20.00	0.03	4.44	-	-	-	1	-	-	-	-	-	-	-	-	5.17
2035	5			5.93	-	9.31	-	0.86	4.44	-	-	-	-	1	-	-	-	-	-	-	-	5.19
2035	6			12.99	-	17.05	-	4.85	4.44	-	-	-	-	-	1	-	-	-	-	-	-	5.32
2035	7			15.54	-	20.30	-	10.66	4.44	-	-	-	-	-	-	1	-	-	-	-	-	5.40
2035	8			13.62	-	17.06	-	8.23	4.44	-	-	-	-	-	-	-	1	-	-	-	-	5.35
2035	9			10.14	-	13.18	-	3.17	4.44	-	-	-	-	-	-	-	-	1	-	-	-	5.28
2035	10			-	23.84	-	13.89	0.20	4.44	-	-	-	-	-	-	-	-	-	1	-	-	5.19
2035	11			-	39.63	-	29.60	-	4.44	-	-	-	-	-	-	-	-	-	-	1	-	5.26
2035	12			-	49.03	-	41.47	-	4.44	-	-	-	-	-	-	-	-	-	-	-	1	5.33
2036	1			-	47.16	-	39.53	-	4.45	1	-	-	-	-	-	-	-	-	-	-	-	5.31
2036	2			-	48.49	-	40.80	-	4.45	-	1	-	-	-	-	-	-	-	-	-	-	5.30
2036	3			-	37.23	-	30.62	0.01	4.45	-	-	1	-	-	-	-	-	-	-	-	-	5.24
2036	4			-	29.15	-	20.00	0.03	4.45	-	-	-	1	-	-	-	-	-	-	-	-	5.18
2036	5			5.93	-	9.31	-	0.86	4.45	-	-	-	-	1	-	-	-	-	-	-	-	5.20
2036	6			12.99	-	17.05	-	4.85	4.45	-	-	-	-	-	1	-	-	-	-	-	-	5.33
2036	7			15.54	-	20.30	-	10.66	4.45	-	-	-	-	-	-	1	-	-	-	-	-	5.41
2036	8			13.62	-	17.06	-	8.23	4.45	-	-	-	-	-	-	-	1	-	-	-	-	5.36
2036	9			10.14	-	13.18	-	3.17	4.45	-	-	-	-	-	-	-	-	1	-	-	-	5.28
2036	10			-	23.84	-	13.89	0.20	4.45	-	-	-	-	-	-	-	-	-	1	-	-	5.19
2036	11			-	39.63	-	29.60	-	4.45	-	-	-	-	-	-	-	-	-	-	1	-	5.27
2036	12			-	49.03	-	41.47	-	4.45	-	-	-	-	-	-	-	-	-	-	-	1	5.33
2037	1			-	47.16	-	39.53	-	4.46	1	-	-	-	-	-	-	-	-	-	-	-	5.31
2037	2			-	48.49	-	40.80	-	4.46	-	1	-	-	-	-	-	-	-	-	-	-	5.31
2037	3			-	37.23	-	30.62	0.01	4.46	-	-	1	-	-	-	-	-	-	-	-	-	5.25
2037	4			-	29.15	-	20.00	0.03	4.46	-	-	-	1	-	-	-	-	-	-	-	-	5.19
2037	5			5.93	-	9.31	-	0.86	4.46	-	-	-	-	1	-	-	-	-	-	-	-	5.20

2037	6			12.99	-	17.05	-	4.85	4.46	-	-	-	-	-	1	-	-	-	-	-	-	5.33
2037	7			15.54	-	20.30	-	10.66	4.46	-	-	-	-	-	-	1	-	-	-	-	-	5.42
2037	8			13.62	-	17.06	-	8.23	4.46	-	-	-	-	-	-	-	1	-	-	-	-	5.36
2037	9			10.14	-	13.18	-	3.17	4.46	-	-	-	-	-	-	-	-	1	-	-	-	5.29
2037	10			-	23.84	-	13.89	0.20	4.46	-	-	-	-	-	-	-	-	-	1	-	-	5.20
2037	11			-	39.63	-	29.60	-	4.46	-	-	-	-	-	-	-	-	-	-	1	-	5.27
2037	12			-	49.03	-	41.47	-	4.46	-	-	-	-	-	-	-	-	-	-	-	1	5.34
2038	1			-	47.16	-	39.53	-	4.47	1	-	-	-	-	-	-	-	-	-	-	-	5.32
2038	2			-	48.49	-	40.80	-	4.47	-	1	-	-	-	-	-	-	-	-	-	-	5.31
2038	3			-	37.23	-	30.62	0.01	4.47	-	-	1	-	-	-	-	-	-	-	-	-	5.25
2038	4			-	29.15	-	20.00	0.03	4.47	-	-	-	1	-	-	-	-	-	-	-	-	5.19
2038	5			5.93	-	9.31	-	0.86	4.47	-	-	-	-	1	-	-	-	-	-	-	-	5.21
2038	6			12.99	-	17.05	-	4.85	4.47	-	-	-	-	-	1	-	-	-	-	-	-	5.34
2038	7			15.54	-	20.30	-	10.66	4.47	-	-	-	-	-	-	1	-	-	-	-	-	5.42
2038	8			13.62	-	17.06	-	8.23	4.47	-	-	-	-	-	-	-	1	-	-	-	-	5.37
2038	9			10.14	-	13.18	-	3.17	4.47	-	-	-	-	-	-	-	-	1	-	-	-	5.30
2038	10			-	23.84	-	13.89	0.20	4.47	-	-	-	-	-	-	-	-	-	1	-	-	5.21
2038	11			-	39.63	-	29.60	-	4.47	-	-	-	-	-	-	-	-	-	-	1	-	5.28
2038	12			-	49.03	-	41.47	-	4.47	-	-	-	-	-	-	-	-	-	-	-	1	5.35
2039	1			-	47.16	-	39.53	-	4.48	1	-	-	-	-	-	-	-	-	-	-	-	5.33
2039	2			-	48.49	-	40.80	-	4.48	-	1	-	-	-	-	-	-	-	-	-	-	5.32
2039	3			-	37.23	-	30.62	0.01	4.48	-	-	1	-	-	-	-	-	-	-	-	-	5.26
2039	4			-	29.15	-	20.00	0.03	4.48	-	-	-	1	-	-	-	-	-	-	-	-	5.20
2039	5			5.93	-	9.31	-	0.86	4.48	-	-	-	-	1	-	-	-	-	-	-	-	5.22
2039	6			12.99	-	17.05	-	4.85	4.48	-	-	-	-	-	1	-	-	-	-	-	-	5.35
2039	7			15.54	-	20.30	-	10.66	4.48	-	-	-	-	-	-	1	-	-	-	-	-	5.43
2039	8			13.62	-	17.06	-	8.23	4.48	-	-	-	-	-	-	-	1	-	-	-	-	5.38
2039	9			10.14	-	13.18	-	3.17	4.48	-	-	-	-	-	-	-	-	1	-	-	-	5.30
2039	10			-	23.84	-	13.89	0.20	4.48	-	-	-	-	-	-	-	-	-	1	-	-	5.21
2039	11			-	39.63	-	29.60	-	4.48	-	-	-	-	-	-	-	-	-	-	1	-	5.29
2039	12			-	49.03	-	41.47	-	4.48	-	-	-	-	-	-	-	-	-	-	-	1	5.35
2040	1			-	47.16	-	39.53	-	4.49	1	-	-	-	-	-	-	-	-	-	-	-	5.33
2040	2			-	48.49	-	40.80	-	4.49	-	1	-	-	-	-	-	-	-	-	-	-	5.33
2040	3			-	37.23	-	30.62	0.01	4.49	-	-	1	-	-	-	-	-	-	-	-	-	5.27
2040	4			-	29.15	-	20.00	0.03	4.49	-	-	-	1	-	-	-	-	-	-	-	-	5.21

2040	5			5.93	-	9.31	-	0.86	4.49	-	-	-	-	1	-	-	-	-	-	-	-	5.22
2040	6			12.99	-	17.05	-	4.85	4.49	-	-	-	-	-	1	-	-	-	-	-	-	5.35
2040	7			15.54	-	20.30	-	10.66	4.49	-	-	-	-	-	-	1	-	-	-	-	-	5.44
2040	8			13.62	-	17.06	-	8.23	4.49	-	-	-	-	-	-	-	1	-	-	-	-	5.38
2040	9			10.14	-	13.18	-	3.17	4.49	-	-	-	-	-	-	-	-	1	-	-	-	5.31
2040	10			-	23.84	-	13.89	0.20	4.49	-	-	-	-	-	-	-	-	-	1	-	-	5.22
2040	11			-	39.63	-	29.60	-	4.49	-	-	-	-	-	-	-	-	-	-	1	-	5.29
2040	12			-	49.03	-	41.47	-	4.49	-	-	-	-	-	-	-	-	-	-	-	1	5.36

Schedule C-7. Cheyenne Light: Variable Statistical Values for Demand Model

Cheyenne Light **Confidential Appendix C**

Cheyenne Light: Variable Statistical Values for Demand Model **Schedule C-7**

Variable	Coefficient	Standard Error	P Value	R2 = 0.9239
cdh	0.002	0.001	0.005	
cdd60	0.005	0.001	0.000	
hdh	0.001	0.000	0.032	
hdd60	0.001	0.000	0.037	
mnthcdd60perday	0.008	0.002	0.000	
lntotemp	0.670	0.030	0.000	
m2	-0.010	0.007	0.128	
m3	-0.056	0.007	0.000	
m4	-0.103	0.007	0.000	
m5	-0.108	0.008	0.000	
m6	-0.058	0.012	0.000	
m7	-0.039	0.017	0.026	
m8	-0.058	0.015	0.000	
m9	-0.067	0.011	0.000	
m10	-0.084	0.008	0.000	
m11	-0.029	0.007	0.000	
m12	0.023	0.007	0.001	
_cons	2.266	0.123	0.000	

Schedule C-8. Cheyenne Light: Base Monthly Customer Class Sales Forecast and Demand Forecast

Cheyenne Light | **Confidential Appendix C**

Cheyenne Light: Base Monthly Customer Class Sales Forecast and Demand Forecast | **Schedule C-8**

Year	Month	Residential Use per Customer (MWh)	Residential Customers	Residential Sales (MWh)	Commercial No Demand Use per Customer (MWh)	Commercial No Demand Customers	Commercial No Demand Sales (MWh)	Commercial General Service Primary & Secondary Sales (MWh)	Industrial Sales (MWh)	Base Total System Demand (MW)
2020	Jan	0.71	38,489.76	27,342.41	1.07	4,482.26	4,796.52	42,319.47	25,561.74	178.19
2020	Feb	0.64	38,517.00	24,477.20	1.01	4,487.86	4,543.44	37,919.03	25,579.20	176.65
2020	Mar	0.61	38,544.30	23,644.16	0.97	4,493.48	4,367.59	38,360.43	26,396.46	166.33
2020	Apr	0.55	38,571.55	21,230.50	0.90	4,499.09	4,053.96	37,249.05	25,476.96	156.68
2020	May	0.51	38,598.82	19,705.60	0.85	4,504.70	3,845.73	36,973.65	24,809.04	159.17
2020	Jun	0.51	38,626.03	19,606.35	0.84	4,510.32	3,785.14	39,775.48	24,729.50	181.27
2020	Jul	0.58	38,653.27	22,475.50	0.94	4,515.93	4,224.05	40,086.43	25,875.66	197.15
2020	Aug	0.60	38,680.52	23,360.42	0.98	4,521.55	4,423.38	42,905.01	19,637.46	186.81
2020	Sep	0.54	38,707.71	20,769.03	0.88	4,527.17	3,998.58	39,765.48	17,016.30	173.65
2020	Oct	0.50	38,734.93	19,246.58	0.84	4,532.79	3,808.05	39,304.80	17,367.78	158.67
2020	Nov	0.54	38,762.13	20,933.14	0.87	4,538.41	3,934.46	36,770.46	16,433.13	170.97
2020	Dec	0.65	38,789.30	25,339.62	1.01	4,544.03	4,593.54	37,979.96	17,164.76	182.81
2021	Jan	0.71	38,841.02	27,555.04	1.06	4,555.43	4,838.94	42,319.47	15,384.93	179.80
2021	Feb	0.63	38,865.55	24,665.68	1.00	4,561.19	4,583.69	37,919.03	14,062.13	178.24
2021	Mar	0.61	38,890.05	23,824.36	0.96	4,566.97	4,406.35	38,360.43	15,384.93	167.82
2021	Apr	0.55	38,914.54	21,390.66	0.89	4,572.74	4,090.00	37,249.05	15,066.57	158.09
2021	May	0.51	38,939.04	19,852.73	0.85	4,578.51	3,879.97	36,973.65	15,384.93	160.61
2021	Jun	0.51	38,963.56	19,751.26	0.83	4,584.29	3,818.90	39,775.48	3,645.54	182.90
2021	Jul	0.58	38,988.02	22,639.88	0.93	4,590.07	4,261.79	40,086.43	8,729.77	198.93
2021	Aug	0.60	39,012.49	23,529.45	0.97	4,595.85	4,462.98	42,905.01	15,568.79	188.50
2021	Sep	0.54	39,036.98	20,917.74	0.88	4,601.63	4,034.43	39,765.48	14,888.65	175.21
2021	Oct	0.50	39,061.41	19,382.91	0.83	4,607.41	3,842.25	39,304.80	15,568.79	160.09
2021	Nov	0.54	39,085.89	21,079.83	0.86	4,613.20	3,969.86	36,770.46	14,888.65	172.51
2021	Dec	0.65	39,110.31	25,515.24	1.00	4,618.98	4,634.94	37,979.96	15,568.79	184.45
2022	Jan	0.71	39,155.58	27,743.80	1.05	4,630.64	4,882.63	42,319.47	16,947.33	181.42
2022	Feb	0.63	39,176.43	24,834.52	1.00	4,636.52	4,625.09	37,919.03	15,473.33	179.85
2022	Mar	0.61	39,197.24	23,987.34	0.96	4,642.40	4,446.16	38,360.43	18,063.33	169.34
2022	Apr	0.55	39,218.03	21,536.89	0.89	4,648.28	4,126.96	37,249.05	17,658.57	159.52
2022	May	0.51	39,238.83	19,988.35	0.84	4,654.16	3,915.05	36,973.65	18,063.33	162.06
2022	Jun	0.51	39,259.64	19,886.07	0.83	4,660.05	3,853.44	39,775.48	17,658.57	184.55
2022	Jul	0.58	39,280.46	22,794.32	0.92	4,665.94	4,300.34	40,086.43	18,063.33	200.72
2022	Aug	0.60	39,301.23	23,689.83	0.96	4,671.82	4,503.37	42,905.01	18,247.19	190.20
2022	Sep	0.54	39,322.03	21,060.22	0.87	4,677.71	4,070.95	39,765.48	17,884.39	176.79
2022	Oct	0.50	39,342.81	19,514.85	0.83	4,683.60	3,877.05	39,304.80	18,247.19	161.54
2022	Nov	0.54	39,363.57	21,223.20	0.85	4,689.50	4,005.82	36,770.46	17,480.65	174.07
2022	Dec	0.65	39,384.33	25,688.65	1.00	4,695.39	4,676.94	37,979.96	18,247.19	186.12
2023	Jan	0.71	39,424.13	27,930.86	1.05	4,706.78	4,926.39	42,319.47	18,063.33	182.93
2023	Feb	0.63	39,443.12	25,000.72	0.99	4,712.29	4,666.07	37,919.03	16,481.33	181.34
2023	Mar	0.61	39,462.12	24,146.68	0.95	4,717.79	4,485.10	38,360.43	18,063.33	170.75
2023	Apr	0.55	39,481.13	21,678.91	0.88	4,723.29	4,162.69	37,249.05	17,658.57	160.85
2023	May	0.51	39,500.11	20,119.17	0.84	4,728.80	3,948.55	36,973.65	18,063.33	163.40

2023	Jun	0.51	39,519.10	20,015.25	0.82	4,734.31	3,886.03	39,775.48	17,658.57	186.09
2023	Jul	0.58	39,538.10	22,941.27	0.91	4,739.81	4,336.28	40,086.43	18,063.33	202.39
2023	Aug	0.60	39,557.07	23,841.41	0.96	4,745.32	4,540.54	42,905.01	17,030.37	191.78
2023	Sep	0.54	39,576.05	21,193.94	0.86	4,750.83	4,104.15	39,765.48	17,480.65	178.26
2023	Oct	0.50	39,595.00	19,637.79	0.82	4,756.34	3,908.28	39,304.80	18,247.19	162.88
2023	Nov	0.54	39,613.96	21,355.87	0.85	4,761.85	4,037.69	36,770.46	17,480.65	175.51
2023	Dec	0.65	39,632.93	25,848.01	0.99	4,767.37	4,713.68	37,979.96	18,247.19	187.66
2024	Jan	0.71	39,669.46	28,102.38	1.04	4,778.51	4,964.65	42,319.47	18,063.33	184.46
2024	Feb	0.63	39,687.06	25,153.95	0.98	4,784.14	4,702.35	37,919.03	17,069.95	182.86
2024	Mar	0.61	39,704.62	24,294.38	0.94	4,789.76	4,520.01	38,360.43	18,063.33	172.17
2024	Apr	0.55	39,722.20	21,811.23	0.87	4,795.39	4,195.13	37,249.05	17,658.57	162.19
2024	May	0.51	39,739.74	20,241.70	0.83	4,801.02	3,979.36	36,973.65	18,063.33	164.77
2024	Jun	0.51	39,757.29	20,136.89	0.81	4,806.66	3,916.38	39,775.48	17,658.57	187.65
2024	Jul	0.58	39,774.85	23,080.39	0.91	4,812.29	4,370.18	40,086.43	18,063.33	204.08
2024	Aug	0.60	39,792.41	23,985.69	0.95	4,817.92	4,576.08	42,905.01	18,247.19	193.38
2024	Sep	0.54	39,809.95	21,321.91	0.86	4,823.56	4,136.31	39,765.48	17,480.65	179.75
2024	Oct	0.50	39,827.50	19,756.13	0.82	4,829.20	3,938.94	39,304.80	18,247.19	164.24
2024	Nov	0.54	39,845.05	21,484.29	0.84	4,834.83	4,069.39	36,770.46	17,480.65	176.98
2024	Dec	0.65	39,862.57	26,003.10	0.98	4,840.47	4,750.74	37,979.96	18,247.19	189.24
2025	Jan	0.71	39,896.61	28,270.34	1.03	4,851.77	5,003.66	42,319.47	18,063.33	185.99
2025	Feb	0.63	39,913.13	25,304.03	0.98	4,857.43	4,739.25	37,919.03	16,947.55	184.38
2025	Mar	0.61	39,929.65	24,439.08	0.94	4,863.10	4,555.44	38,360.43	18,063.33	173.60
2025	Apr	0.55	39,946.14	21,940.91	0.87	4,868.76	4,227.96	37,249.05	17,658.57	163.54
2025	May	0.51	39,962.68	20,361.88	0.82	4,874.42	4,010.46	36,973.65	18,063.33	166.14
2025	Jun	0.51	39,979.18	20,256.24	0.81	4,880.09	3,946.94	39,775.48	6,237.54	189.20
2025	Jul	0.58	39,995.66	23,216.94	0.90	4,885.76	4,404.24	40,086.43	11,408.17	205.78
2025	Aug	0.60	40,012.18	24,127.36	0.94	4,891.43	4,611.70	42,905.01	18,247.19	194.99
2025	Sep	0.54	40,028.66	21,447.63	0.85	4,897.09	4,168.46	39,765.48	17,480.65	181.25
2025	Oct	0.50	40,045.16	19,872.41	0.81	4,902.77	3,969.51	39,304.80	18,247.19	165.61
2025	Nov	0.54	40,061.62	21,610.52	0.84	4,908.44	4,100.94	36,770.46	17,480.65	178.45
2025	Dec	0.65	40,078.13	26,155.63	0.97	4,914.11	4,787.51	37,979.96	18,247.19	190.81
2026	Jan	0.71	40,110.36	28,435.16	1.02	4,925.54	5,042.35	42,319.47	18,063.33	187.53
2026	Feb	0.63	40,126.09	25,450.88	0.97	4,931.30	4,775.91	37,919.03	17,069.95	185.91
2026	Mar	0.61	40,141.86	24,580.28	0.93	4,937.05	4,590.67	38,360.43	18,063.33	175.04
2026	Apr	0.55	40,157.59	22,067.11	0.86	4,942.81	4,260.68	37,249.05	17,658.57	164.90
2026	May	0.51	40,173.30	20,478.43	0.82	4,948.57	4,041.50	36,973.65	18,063.33	167.52
2026	Jun	0.51	40,189.05	20,371.67	0.80	4,954.33	3,977.49	39,775.48	17,658.57	190.77
2026	Jul	0.58	40,204.77	23,348.65	0.89	4,960.10	4,438.34	40,086.43	18,063.33	207.49
2026	Aug	0.60	40,220.49	24,263.58	0.94	4,965.86	4,647.42	42,905.01	18,247.19	196.61
2026	Sep	0.54	40,236.22	21,568.19	0.84	4,971.62	4,200.75	39,765.48	17,480.65	182.75
2026	Oct	0.50	40,251.96	19,983.60	0.80	4,977.39	4,000.27	39,304.80	18,247.19	166.98
2026	Nov	0.54	40,267.66	21,730.88	0.83	4,983.16	4,132.72	36,770.46	17,480.65	179.93
2026	Dec	0.65	40,283.37	26,300.60	0.97	4,988.92	4,824.62	37,979.96	18,247.19	192.39
2027	Jan	0.71	40,314.34	28,591.40	1.02	5,000.39	5,081.30	42,319.47	18,063.33	189.05
2027	Feb	0.63	40,329.61	25,590.18	0.96	5,006.09	4,812.66	37,919.03	17,069.95	187.41
2027	Mar	0.61	40,344.84	24,714.24	0.92	5,011.79	4,625.87	38,360.43	18,063.33	176.46
2027	Apr	0.55	40,360.08	22,186.89	0.86	5,017.49	4,293.22	37,249.05	17,658.57	166.23
2027	May	0.51	40,375.33	20,589.15	0.81	5,023.19	4,072.24	36,973.65	18,063.33	168.87

2027	Jun	0.51	40,390.58	20,481.36	0.80	5,028.90	4,007.64	39,775.48	17,658.57	192.32
2027	Jul	0.58	40,405.80	23,473.84	0.89	5,034.60	4,471.85	40,086.43	18,063.33	209.17
2027	Aug	0.60	40,421.06	24,393.17	0.93	5,040.31	4,682.37	42,905.01	18,247.19	198.20
2027	Sep	0.54	40,436.29	21,682.90	0.84	5,046.01	4,232.23	39,765.48	17,480.65	184.23
2027	Oct	0.50	40,451.48	20,089.43	0.80	5,051.72	4,030.12	39,304.80	18,247.19	168.34
2027	Nov	0.54	40,466.73	21,845.49	0.82	5,057.43	4,163.44	36,770.46	17,480.65	181.39
2027	Dec	0.65	40,481.93	26,438.73	0.96	5,063.14	4,860.36	37,979.96	18,247.19	193.95
2028	Jan	0.71	40,511.91	28,740.39	1.01	5,074.53	5,118.68	42,319.47	18,063.33	190.56
2028	Feb	0.63	40,526.59	25,722.98	0.95	5,080.21	4,847.96	37,919.03	17,069.95	188.90
2028	Mar	0.61	40,541.32	24,842.03	0.92	5,085.88	4,659.70	38,360.43	18,063.33	177.87
2028	Apr	0.55	40,556.01	22,301.15	0.85	5,091.56	4,324.53	37,249.05	17,658.57	167.56
2028	May	0.51	40,570.71	20,694.77	0.80	5,097.24	4,101.86	36,973.65	18,063.33	170.22
2028	Jun	0.51	40,585.42	20,586.02	0.79	5,102.92	4,036.70	39,775.48	17,658.57	193.85
2028	Jul	0.58	40,600.13	23,593.34	0.88	5,108.61	4,504.19	40,086.43	18,063.33	210.83
2028	Aug	0.60	40,614.84	24,516.85	0.92	5,114.29	4,716.13	42,905.01	18,247.19	199.78
2028	Sep	0.54	40,629.53	21,792.40	0.83	5,119.98	4,262.65	39,765.48	17,480.65	185.70
2028	Oct	0.50	40,644.21	20,190.50	0.79	5,125.66	4,059.01	39,304.80	18,247.19	169.67
2028	Nov	0.54	40,658.91	21,954.95	0.82	5,131.35	4,193.21	36,770.46	17,480.65	182.83
2028	Dec	0.65	40,673.61	26,570.72	0.95	5,137.04	4,894.99	37,979.96	18,247.19	195.49
2029	Jan	0.71	40,702.20	28,882.70	1.00	5,148.42	5,154.99	42,319.47	18,063.33	192.05
2029	Feb	0.63	40,716.10	25,849.86	0.95	5,154.11	4,882.29	37,919.03	17,069.95	190.39
2029	Mar	0.61	40,730.04	24,964.09	0.91	5,159.80	4,692.64	38,360.43	18,063.33	179.26
2029	Apr	0.55	40,743.95	22,410.31	0.84	5,165.50	4,355.03	37,249.05	17,658.57	168.87
2029	May	0.51	40,757.83	20,795.65	0.80	5,171.19	4,130.74	36,973.65	18,063.33	171.56
2029	Jun	0.51	40,771.75	20,685.98	0.79	5,176.89	4,065.07	39,775.48	17,658.57	195.37
2029	Jul	0.58	40,785.63	23,707.43	0.88	5,182.59	4,535.78	40,086.43	18,063.33	212.49
2029	Aug	0.60	40,799.55	24,634.94	0.92	5,188.28	4,749.15	42,905.01	18,247.19	201.35
2029	Sep	0.54	40,813.45	21,896.95	0.83	5,193.99	4,292.44	39,765.48	17,480.65	187.16
2029	Oct	0.50	40,827.31	20,286.97	0.79	5,199.69	4,087.33	39,304.80	18,247.19	171.01
2029	Nov	0.54	40,841.21	22,059.43	0.81	5,205.39	4,222.40	36,770.46	17,480.65	184.27
2029	Dec	0.65	40,855.12	26,696.65	0.95	5,211.09	4,929.01	37,979.96	18,247.19	197.03
2030	Jan	0.71	40,882.17	29,018.21	0.99	5,222.46	5,190.64	42,319.47	18,063.33	193.54
2030	Feb	0.64	40,895.31	25,970.39	0.94	5,228.12	4,915.94	37,919.03	17,069.95	191.86
2030	Mar	0.61	40,908.45	25,079.74	0.90	5,233.79	4,724.89	38,360.43	18,063.33	180.65
2030	Apr	0.55	40,921.60	22,513.47	0.84	5,239.45	4,384.87	37,249.05	17,658.57	170.17
2030	May	0.51	40,934.80	20,890.82	0.79	5,245.12	4,158.96	36,973.65	18,063.33	172.88
2030	Jun	0.51	40,947.91	20,780.02	0.78	5,250.79	4,092.75	39,775.48	17,658.57	196.88
2030	Jul	0.58	40,961.08	23,814.55	0.87	5,256.46	4,566.57	40,086.43	18,063.33	214.12
2030	Aug	0.60	40,974.20	24,745.52	0.91	5,262.13	4,781.29	42,905.01	18,247.19	202.90
2030	Sep	0.54	40,987.38	21,994.63	0.82	5,267.80	4,321.40	39,765.48	17,480.65	188.60
2030	Oct	0.50	41,000.51	20,376.88	0.78	5,273.47	4,114.81	39,304.80	18,247.19	172.33
2030	Nov	0.54	41,013.65	22,156.58	0.81	5,279.15	4,250.71	36,770.46	17,480.65	185.69
2030	Dec	0.65	41,026.80	26,813.45	0.94	5,284.82	4,961.96	37,979.96	18,247.19	198.55
2031	Jan	0.71	41,052.59	29,143.10	0.99	5,296.13	5,225.12	42,319.47	18,063.33	195.00
2031	Feb	0.64	41,065.27	26,081.09	0.93	5,301.77	4,948.50	37,919.03	17,069.95	193.31
2031	Mar	0.61	41,077.96	25,185.61	0.90	5,307.40	4,756.08	38,360.43	18,063.33	182.01
2031	Apr	0.55	41,090.62	22,607.57	0.83	5,313.04	4,413.73	37,249.05	17,658.57	171.46
2031	May	0.51	41,103.32	20,977.25	0.79	5,318.68	4,186.24	36,973.65	18,063.33	174.19

2031	Jun	0.51	41,115.98	20,865.15	0.77	5,324.31	4,119.51	39,775.48	17,658.57	198.37
2031	Jul	0.58	41,128.65	23,911.11	0.86	5,329.96	4,596.34	40,086.43	18,063.33	215.74
2031	Aug	0.60	41,141.32	24,844.85	0.90	5,335.60	4,812.36	42,905.01	18,247.19	204.43
2031	Sep	0.54	41,154.00	22,082.00	0.81	5,341.24	4,349.40	39,765.48	17,480.65	190.03
2031	Oct	0.50	41,166.68	20,457.00	0.77	5,346.89	4,141.39	39,304.80	18,247.19	173.63
2031	Nov	0.54	41,179.32	22,242.76	0.80	5,352.53	4,278.07	36,770.46	17,480.65	187.10
2031	Dec	0.65	41,191.96	26,916.63	0.93	5,358.17	4,993.80	37,979.96	18,247.19	200.05
2032	Jan	0.71	41,216.76	29,253.36	0.98	5,369.38	5,258.39	42,319.47	18,063.33	196.44
2032	Feb	0.63	41,228.87	26,179.12	0.93	5,374.94	4,979.87	37,919.03	17,069.95	194.73
2032	Mar	0.61	41,240.98	25,279.64	0.89	5,380.51	4,786.10	38,360.43	18,063.33	183.35
2032	Apr	0.55	41,253.10	22,691.42	0.82	5,386.07	4,441.46	37,249.05	17,658.57	172.72
2032	May	0.51	41,265.21	21,054.53	0.78	5,391.63	4,212.43	36,973.65	18,063.33	175.47
2032	Jun	0.51	41,277.34	20,941.51	0.77	5,397.20	4,145.17	39,775.48	17,658.57	199.83
2032	Jul	0.58	41,289.43	23,998.01	0.86	5,402.77	4,624.84	40,086.43	18,063.33	217.33
2032	Aug	0.60	41,301.52	24,934.52	0.90	5,408.33	4,842.06	42,905.01	18,247.19	205.94
2032	Sep	0.54	41,313.65	22,161.16	0.81	5,413.91	4,376.12	39,765.48	17,480.65	191.43
2032	Oct	0.50	41,325.75	20,529.83	0.77	5,419.48	4,166.72	39,304.80	18,247.19	174.91
2032	Nov	0.54	41,337.85	22,321.42	0.79	5,425.05	4,304.12	36,770.46	17,480.65	188.47
2032	Dec	0.65	41,349.95	27,011.17	0.93	5,430.62	5,024.06	37,979.96	18,247.19	201.52
2033	Jan	0.71	41,373.86	29,354.96	0.97	5,441.71	5,290.00	42,319.47	18,063.33	197.85
2033	Feb	0.63	41,385.70	26,269.68	0.92	5,447.23	5,009.70	37,919.03	17,069.95	196.14
2033	Mar	0.61	41,397.50	25,366.74	0.88	5,452.75	4,814.66	38,360.43	18,063.33	184.68
2033	Apr	0.55	41,409.30	22,769.28	0.82	5,458.27	4,467.87	37,249.05	17,658.57	173.97
2033	May	0.51	41,421.15	21,126.49	0.78	5,463.80	4,237.39	36,973.65	18,063.33	176.73
2033	Jun	0.51	41,432.96	21,012.79	0.76	5,469.32	4,169.64	39,775.48	17,658.57	201.27
2033	Jul	0.58	41,444.78	24,079.39	0.85	5,474.84	4,652.04	40,086.43	18,063.33	218.90
2033	Aug	0.60	41,456.60	25,018.75	0.89	5,480.36	4,870.44	42,905.01	18,247.19	207.42
2033	Sep	0.54	41,468.39	22,235.69	0.80	5,485.89	4,401.67	39,765.48	17,480.65	192.81
2033	Oct	0.50	41,480.21	20,598.60	0.76	5,491.42	4,190.96	39,304.80	18,247.19	176.17
2033	Nov	0.54	41,492.00	22,395.87	0.79	5,496.95	4,329.07	36,770.46	17,480.65	189.83
2033	Dec	0.65	41,503.84	27,100.92	0.92	5,502.48	5,053.08	37,979.96	18,247.19	202.98
2034	Jan	0.71	41,527.35	29,451.98	0.96	5,513.48	5,320.32	42,319.47	18,063.33	199.25
2034	Feb	0.63	41,539.08	26,356.40	0.91	5,518.95	5,038.30	37,919.03	17,069.95	197.52
2034	Mar	0.61	41,550.77	25,450.37	0.88	5,524.42	4,842.04	38,360.43	18,063.33	185.98
2034	Apr	0.55	41,562.50	22,844.26	0.81	5,529.89	4,493.18	37,249.05	17,658.57	175.20
2034	May	0.51	41,574.19	21,195.96	0.77	5,535.36	4,261.29	36,973.65	18,063.33	177.98
2034	Jun	0.51	41,585.89	21,081.79	0.76	5,540.84	4,193.08	39,775.48	17,658.57	202.69
2034	Jul	0.58	41,597.59	24,158.35	0.84	5,546.31	4,678.08	40,086.43	18,063.33	220.44
2034	Aug	0.60	41,609.29	25,100.68	0.88	5,551.79	4,897.60	42,905.01	18,247.19	208.89
2034	Sep	0.54	41,621.00	22,308.43	0.80	5,557.27	4,426.12	39,765.48	17,480.65	194.17
2034	Oct	0.50	41,632.71	20,665.90	0.76	5,562.75	4,214.14	39,304.80	18,247.19	177.41
2034	Nov	0.54	41,644.39	22,468.96	0.78	5,568.23	4,352.93	36,770.46	17,480.65	191.17
2034	Dec	0.65	41,656.11	27,189.23	0.91	5,573.71	5,080.81	37,979.96	18,247.19	204.41
2035	Jan	0.71	41,679.35	29,548.07	0.96	5,584.58	5,349.27	42,319.47	18,063.33	200.62
2035	Feb	0.63	41,690.92	26,442.60	0.91	5,589.98	5,065.58	37,919.03	17,069.95	198.88
2035	Mar	0.61	41,702.45	25,533.79	0.87	5,595.37	4,868.13	38,360.43	18,063.33	187.26
2035	Apr	0.55	41,714.03	22,919.33	0.81	5,600.77	4,517.28	37,249.05	17,658.57	176.40
2035	May	0.51	41,725.57	21,265.78	0.76	5,606.17	4,284.03	36,973.65	18,063.33	179.20

2035	Jun	0.51	41,737.11	21,151.40	0.75	5,611.57	4,215.34	39,775.48	17,658.57	204.08
2035	Jul	0.58	41,748.69	24,238.32	0.84	5,616.97	4,702.80	40,086.43	18,063.33	221.96
2035	Aug	0.60	41,760.20	25,183.95	0.88	5,622.37	4,923.35	42,905.01	18,247.19	210.32
2035	Sep	0.54	41,771.75	22,382.60	0.79	5,627.77	4,449.28	39,765.48	17,480.65	195.50
2035	Oct	0.50	41,783.30	20,734.77	0.75	5,633.17	4,236.08	39,304.80	18,247.19	178.63
2035	Nov	0.54	41,794.86	22,544.03	0.78	5,638.58	4,375.48	36,770.46	17,480.65	192.49
2035	Dec	0.65	41,806.38	27,280.26	0.90	5,643.98	5,107.00	37,979.96	18,247.19	205.81
2036	Jan	0.71	41,829.59	29,646.81	0.95	5,654.77	5,376.63	42,319.47	18,063.33	201.98
2036	Feb	0.63	41,841.28	26,530.60	0.90	5,660.16	5,091.43	37,919.03	17,069.95	200.22
2036	Mar	0.61	41,852.94	25,618.43	0.86	5,665.55	4,892.91	38,360.43	18,063.33	188.52
2036	Apr	0.55	41,864.63	22,995.00	0.80	5,670.95	4,540.21	37,249.05	17,658.57	177.60
2036	May	0.51	41,876.29	21,335.70	0.76	5,676.34	4,305.73	36,973.65	18,063.33	180.42
2036	Jun	0.51	41,887.96	21,220.66	0.75	5,681.73	4,236.63	39,775.48	17,658.57	205.47
2036	Jul	0.58	41,899.62	24,317.35	0.83	5,687.12	4,726.50	40,086.43	18,063.33	223.46
2036	Aug	0.60	41,911.29	25,265.74	0.87	5,692.51	4,948.08	42,905.01	18,247.19	211.75
2036	Sep	0.54	41,922.93	22,454.99	0.78	5,697.91	4,471.58	39,765.48	17,480.65	196.82
2036	Oct	0.50	41,934.60	20,801.55	0.75	5,703.31	4,257.26	39,304.80	18,247.19	179.84
2036	Nov	0.54	41,946.24	22,616.31	0.77	5,708.71	4,397.29	36,770.46	17,480.65	193.79
2036	Dec	0.65	41,957.92	27,367.39	0.90	5,714.10	5,132.40	37,979.96	18,247.19	207.21
2037	Jan	0.71	41,981.38	29,740.28	0.94	5,724.87	5,403.22	42,319.47	18,063.33	203.32
2037	Feb	0.63	41,993.23	26,613.51	0.89	5,730.24	5,116.52	37,919.03	17,069.95	201.56
2037	Mar	0.61	42,005.04	25,697.79	0.86	5,735.61	4,916.95	38,360.43	18,063.33	189.78
2037	Apr	0.55	42,016.86	23,065.58	0.79	5,740.98	4,562.45	37,249.05	17,658.57	178.78
2037	May	0.51	42,028.69	21,400.60	0.75	5,746.35	4,326.75	36,973.65	18,063.33	181.62
2037	Jun	0.51	42,040.51	21,284.63	0.74	5,751.73	4,257.26	39,775.48	17,658.57	206.84
2037	Jul	0.58	42,052.34	24,390.00	0.82	5,757.10	4,749.44	40,086.43	18,063.33	224.95
2037	Aug	0.60	42,064.17	25,340.55	0.86	5,762.48	4,972.03	42,905.01	18,247.19	213.16
2037	Sep	0.54	42,075.97	22,520.86	0.78	5,767.85	4,493.15	39,765.48	17,480.65	198.14
2037	Oct	0.50	42,087.81	20,862.01	0.74	5,773.23	4,277.73	39,304.80	18,247.19	181.04
2037	Nov	0.54	42,099.61	22,681.44	0.76	5,778.61	4,418.37	36,770.46	17,480.65	195.08
2037	Dec	0.65	42,111.42	27,445.44	0.89	5,783.99	5,156.93	37,979.96	18,247.19	208.59
2038	Jan	0.71	42,135.36	29,823.71	0.94	5,794.75	5,428.92	42,319.47	18,063.33	204.66
2038	Feb	0.63	42,147.50	26,687.64	0.89	5,800.13	5,140.81	37,919.03	17,069.95	202.89
2038	Mar	0.61	42,159.60	25,768.84	0.85	5,805.51	4,940.25	38,360.43	18,063.33	191.04
2038	Apr	0.55	42,171.70	23,128.89	0.79	5,810.89	4,584.02	37,249.05	17,658.57	179.96
2038	May	0.51	42,183.85	21,458.93	0.75	5,816.27	4,347.17	36,973.65	18,063.33	182.82
2038	Jun	0.51	42,195.96	21,342.22	0.73	5,821.66	4,277.31	39,775.48	17,658.57	208.20
2038	Jul	0.58	42,208.07	24,455.49	0.82	5,827.04	4,771.76	40,086.43	18,063.33	226.44
2038	Aug	0.60	42,220.15	25,408.05	0.86	5,832.44	4,995.36	42,905.01	18,247.19	214.57
2038	Sep	0.53	42,232.27	22,580.43	0.77	5,837.82	4,514.18	39,765.48	17,480.65	199.45
2038	Oct	0.50	42,244.40	20,916.77	0.74	5,843.21	4,297.72	39,304.80	18,247.19	182.24
2038	Nov	0.54	42,256.48	22,740.52	0.76	5,848.60	4,438.98	36,770.46	17,480.65	196.37
2038	Dec	0.65	42,268.57	27,516.40	0.89	5,853.99	5,180.93	37,979.96	18,247.19	209.97
2039	Jan	0.71	42,293.21	29,900.00	0.93	5,864.78	5,454.08	42,319.47	18,063.33	206.00
2039	Feb	0.63	42,305.68	26,755.64	0.88	5,870.17	5,164.59	37,919.03	17,069.95	204.22
2039	Mar	0.61	42,318.19	25,834.32	0.84	5,875.56	4,963.06	38,360.43	18,063.33	192.28
2039	Apr	0.55	42,330.70	23,187.48	0.78	5,880.96	4,605.15	37,249.05	17,658.57	181.14
2039	May	0.51	42,343.18	21,513.09	0.74	5,886.36	4,367.17	36,973.65	18,063.33	184.02

2039	Jun	0.51	42,355.70	21,395.92	0.73	5,891.75	4,296.94	39,775.48	17,658.57	209.56
2039	Jul	0.58	42,368.18	24,516.83	0.81	5,897.15	4,793.62	40,086.43	18,063.33	227.92
2039	Aug	0.60	42,380.67	25,471.59	0.85	5,902.55	5,018.20	42,905.01	18,247.19	215.97
2039	Sep	0.53	42,393.16	22,636.71	0.77	5,907.95	4,534.78	39,765.48	17,480.65	200.75
2039	Oct	0.49	42,405.61	20,968.71	0.73	5,913.35	4,317.29	39,304.80	18,247.19	183.43
2039	Nov	0.54	42,418.11	22,796.82	0.75	5,918.75	4,459.15	36,770.46	17,480.65	197.65
2039	Dec	0.65	42,430.57	27,584.30	0.88	5,924.15	5,204.43	37,979.96	18,247.19	211.34
2040	Jan	0.71	42,456.11	29,973.84	0.92	5,935.00	5,478.76	42,319.47	18,063.33	207.35
2040	Feb	0.63	42,469.19	26,822.07	0.87	5,940.45	5,187.96	37,919.03	17,069.95	205.55
2040	Mar	0.61	42,482.23	25,898.71	0.84	5,945.90	4,985.50	38,360.43	18,063.33	193.54
2040	Apr	0.55	42,495.28	23,245.53	0.78	5,951.35	4,625.97	37,249.05	17,658.57	182.32
2040	May	0.51	42,508.34	21,567.20	0.74	5,956.80	4,386.90	36,973.65	18,063.33	185.22
2040	Jun	0.50	42,521.35	21,449.94	0.72	5,962.26	4,316.36	39,775.48	17,658.57	210.93
2040	Jul	0.58	42,534.41	24,579.01	0.81	5,967.72	4,815.28	40,086.43	18,063.33	229.41
2040	Aug	0.60	42,547.43	25,536.45	0.84	5,973.17	5,040.86	42,905.01	18,247.19	217.38
2040	Sep	0.53	42,560.50	22,694.61	0.76	5,978.62	4,555.25	39,765.48	17,480.65	202.06
2040	Oct	0.49	42,573.53	21,022.60	0.72	5,984.08	4,336.78	39,304.80	18,247.19	184.63
2040	Nov	0.54	42,586.57	22,855.65	0.75	5,989.54	4,479.27	36,770.46	17,480.65	198.94
2040	Dec	0.65	42,599.61	27,655.79	0.87	5,995.00	5,227.91	37,979.96	18,247.19	212.72

Schedule C-9. Cheyenne Light: Base Annual Customer Class Sales Forecast and Demand Forecast

Cheyenne Light | **Confidential Appendix C**

Cheyenne Light: Base Annual Customer Class Sales Forecast and Demand Forecast | **Schedule C-9**

Year	Residential Use per Customer (MWh)	Residential Customers	Residential Sales (MWh)	Commercial No Demand Use per Customer (MWh)	Commercial No Demand Customers	Commercial No Demand Sales (MWh)	Commercial General Service Primary & Secondary Sales (MWh)	Industrial Sales (MWh)	Base Total System Demand (MW)
2020	6.94	463,675.32	268,130.50	11.16	54,157.57	50,374.44	469,409.25	266,047.99	197.15
2021	6.93	467,708.86	270,104.79	11.08	55,046.26	50,824.11	469,409.25	164,142.47	198.93
2022	6.93	471,240.18	271,948.03	11.00	55,956.02	51,283.81	469,409.25	212,034.40	200.72
2023	6.92	474,342.82	273,709.88	10.92	56,844.78	51,715.46	469,409.25	212,537.84	202.39
2024	6.93	477,192.70	275,372.03	10.84	57,713.75	52,119.51	469,409.25	214,343.28	204.08
2025	6.93	479,848.80	277,002.96	10.76	58,595.15	52,526.06	469,409.25	196,144.69	205.78
2026	6.93	482,362.72	278,579.03	10.68	59,486.64	52,932.72	469,409.25	214,343.28	207.49
2027	6.93	484,778.07	280,076.77	10.60	60,381.06	53,333.30	469,409.25	214,343.28	209.17
2028	6.94	487,113.19	281,506.10	10.52	61,269.26	53,719.62	469,409.25	214,343.28	210.83
2029	6.94	489,344.14	282,870.93	10.45	62,156.94	54,096.87	469,409.25	214,343.28	212.49
2030	6.94	491,453.86	284,154.25	10.37	63,043.57	54,464.80	469,409.25	214,343.28	214.12
2031	6.94	493,467.67	285,314.13	10.29	63,925.71	54,820.53	469,409.25	214,343.28	215.74
2032	6.94	495,400.41	286,355.69	10.22	64,799.88	55,161.35	469,409.25	214,343.28	217.33
2033	6.93	497,266.29	287,329.15	10.14	65,665.02	55,486.51	469,409.25	214,343.28	218.90
2034	6.93	499,100.87	288,272.32	10.07	66,523.00	55,797.89	469,409.25	214,343.28	220.44
2035	6.93	500,914.61	289,224.89	9.99	67,371.27	56,093.63	469,409.25	214,343.28	221.96
2036	6.93	502,725.29	290,170.54	9.92	68,213.16	56,376.64	469,409.25	214,343.28	223.46
2037	6.92	504,557.03	291,042.68	9.85	69,053.03	56,650.81	469,409.25	214,343.28	224.95
2038	6.92	506,423.91	291,827.87	9.77	69,892.32	56,917.38	469,409.25	214,343.28	226.44
2039	6.91	508,342.96	292,561.41	9.70	70,733.46	57,178.45	469,409.25	214,343.28	227.92
2040	6.90	510,334.55	293,301.40	9.63	71,579.91	57,436.81	469,409.25	214,343.28	229.41

Schedule C-10. Cheyenne Light: Historical and Forecasted Variable Values for Residential Use Per Customer Model

Cheyenne Light | **Confidential Appendix C**

Cheyenne Light: Historical and Forecasted Variable Values for Residential Use Per Customer Model | **Schedule C-10**

Year	Month	cdd60	hdd60	lnincome12	trend	m1	m2	m3	m4	m5	m6	m7	m8	m9	m10	m11	m12	ln(upc)
2005	1	-	984	11.49	1.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.31
2005	2	-	749	11.49	1.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.46
2005	3	-	712	11.50	1.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.47
2005	4	-	610	11.50	1.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.57
2005	5	-	489	11.50	1.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.63
2005	6	36	160	11.50	1.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.66
2005	7	289	1	11.50	1.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.48
2005	8	296	16	11.50	1.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.49
2005	9	214	17	11.50	1.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.58
2005	10	37	223	11.50	1.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.67
2005	11	-	452	11.50	1.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.61
2005	12	-	941	11.51	2.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.38
2006	1	-	729	11.51	2.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.37
2006	2	-	913	11.52	2.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.43
2006	3	-	902	11.52	2.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.43
2006	4	2	594	11.52	2.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.56
2006	5	-	413	11.53	2.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.64
2006	6	185	30	11.53	2.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.58
2006	7	215	3	11.53	2.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.53
2006	8	383	-	11.54	2.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.42
2006	9	110	56	11.54	2.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.63
2006	10	8	305	11.55	2.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.66
2006	11	-	637	11.55	2.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.56
2006	12	-	752	11.55	3.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.40
2007	1	-	1,140	11.56	3.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.27
2007	2	-	1,093	11.56	3.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.38
2007	3	-	662	11.56	3.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.47
2007	4	-	617	11.56	3.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.55
2007	5	19	307	11.56	3.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.64
2007	6	34	159	11.56	3.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.65
2007	7	307	-	11.56	3.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.46

2007	8	389	-	11.56	3.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.41
2007	9	197	48	11.56	3.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.57
2007	10	18	170	11.56	3.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.68
2007	11	-	454	11.57	3.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.60
2007	12	-	959	11.57	4.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.36
2008	1	-	1,083	11.57	4.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.28
2008	2	-	1,158	11.57	4.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.37
2008	3	-	755	11.58	4.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.45
2008	4	-	746	11.58	4.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.52
2008	5	-	461	11.59	4.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.62
2008	6	35	152	11.59	4.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.65
2008	7	218	-	11.60	4.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.51
2008	8	361	13	11.60	4.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.42
2008	9	80	120	11.60	4.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2008	10	19	226	11.61	4.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.66
2008	11	-	491	11.61	4.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.57
2008	12	-	854	11.62	5.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.37
2009	1	-	1,014	11.62	5.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.28
2009	2	-	891	11.61	5.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.41
2009	3	-	692	11.61	5.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.45
2009	4	-	689	11.60	5.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.53
2009	5	4	420	11.60	5.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.63
2009	6	21	154	11.60	5.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.66
2009	7	153	4	11.59	5.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.57
2009	8	202	14	11.59	5.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.54
2009	9	138	26	11.58	5.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2009	10	4	478	11.58	5.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.63
2009	11	-	615	11.57	5.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.57
2009	12	-	1,029	11.57	6.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.36
2010	1	-	1,020	11.57	6.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.31
2010	2	-	988	11.57	6.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.42
2010	3	-	858	11.57	6.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.44
2010	4	-	651	11.57	6.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.56
2010	5	-	551	11.57	6.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.62
2010	6	46	136	11.58	6.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.66

2010	7	176	11	11.58	6.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.56
2010	8	307	-	11.58	6.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.48
2010	9	186	22	11.58	6.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.59
2010	10	49	105	11.58	6.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.68
2010	11	-	544	11.58	6.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.59
2010	12	-	834	11.59	7.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.40
2011	1	-	1,062	11.59	7.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.30
2011	2	-	1,079	11.60	7.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.39
2011	3	-	769	11.60	7.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.45
2011	4	-	570	11.61	7.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.57
2011	5	1	509	11.61	7.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.62
2011	6	35	203	11.62	7.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.64
2011	7	197	20	11.62	7.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.53
2011	8	342	-	11.63	7.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.44
2011	9	211	52	11.63	7.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.55
2011	10	50	169	11.64	7.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.65
2011	11	-	690	11.64	7.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.54
2011	12	-	928	11.65	8.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.36
2012	1	-	861	11.65	8.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.32
2012	2	-	1,003	11.65	8.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.39
2012	3	-	752	11.66	8.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.44
2012	4	-	369	11.66	8.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.59
2012	5	11	268	11.66	8.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.65
2012	6	90	80	11.66	8.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.62
2012	7	330	4	11.66	8.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.43
2012	8	372	-	11.66	8.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.42
2012	9	208	21	11.66	8.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.56
2012	10	12	269	11.66	8.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.66
2012	11	-	558	11.66	8.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.57
2012	12	-	670	11.66	9.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.41
2013	1	-	1,201	11.66	9.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.25
2013	2	-	876	11.66	9.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.42
2013	3	-	815	11.66	9.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.43
2013	4	-	814	11.66	9.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.51
2013	5	20	554	11.66	9.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.59

2013	6	86	94	11.65	9.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.63
2013	7	313	-	11.65	9.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.46
2013	8	222	-	11.65	9.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.53
2013	9	304	15	11.65	9.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.50
2013	10	21	283	11.65	9.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.66
2013	11	-	607	11.65	9.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.57
2013	12	-	1,010	11.65	10.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.36
2014	1	-	908	11.64	10.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.32
2014	2	-	1,125	11.64	10.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.38
2014	3	-	752	11.64	10.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.46
2014	4	-	635	11.64	10.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.56
2014	5	1	414	11.64	10.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.64
2014	6	34	91	11.64	10.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2014	7	183	6	11.64	10.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.56
2014	8	271	2	11.64	10.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2014	9	117	77	11.64	10.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.63
2014	10	78	146	11.64	10.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.66
2014	11	3	557	11.64	10.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.59
2014	12	-	717	11.64	11.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.42
2015	1	-	1,124	11.64	11.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.29
2015	2	-	643	11.64	11.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.49
2015	3	3	862	11.64	11.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.44
2015	4	-	453	11.64	11.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2015	5	-	436	11.64	11.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.65
2015	6	50	186	11.64	11.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.65
2015	7	229	11	11.64	11.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.53
2015	8	308	-	11.64	11.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.49
2015	9	221	15	11.64	11.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.58
2015	10	66	77	11.64	11.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.69
2015	11	-	460	11.64	11.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2015	12	-	870	11.64	12.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.40
2016	1	-	1,129	11.64	12.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.30
2016	2	-	847	11.63	12.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.46
2016	3	-	552	11.63	12.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.52
2016	4	-	624	11.63	12.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.58

2016	5	1	505	11.63	12.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.65
2016	6	79	135	11.62	12.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.66
2016	7	290	-	11.62	12.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.51
2016	8	339	-	11.62	12.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.48
2016	9	129	50	11.61	12.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.65
2016	10	52	157	11.61	12.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2016	11	4	276	11.61	12.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.67
2016	12	-	931	11.61	13.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.41
2017	1	-	1,051	11.61	13.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.33
2017	2	-	826	11.61	13.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.48
2017	3	-	640	11.61	13.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.52
2017	4	-	432	11.61	13.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.63
2017	5	6	375	11.61	13.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.68
2017	6	53	185	11.61	13.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2017	7	258	8	11.61	13.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2017	8	271	5	11.61	13.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.54
2017	9	254	1	11.62	13.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.58
2017	10	4	336	11.62	13.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2017	11	4	535	11.62	13.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2017	12	-	592	11.62	14.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.48
2018	1	-	966	11.62	14.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.35
2018	2	-	913	11.62	14.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.46
2018	3	-	832	11.63	14.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.48
2018	4	-	645	11.63	14.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.59
2018	5	1	322	11.63	14.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.69
2018	6	134	58	11.63	14.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.65
2018	7	257	18	11.63	14.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.53
2018	8	255	1	11.64	14.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.55
2018	9	192	16	11.64	14.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2018	10	52	369	11.64	14.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.66
2018	11	-	585	11.64	14.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.61
2018	12	-	856	11.64	15.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.42
2019	1	-	893	11.64	15.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.36
2019	2	-	940	11.65	15.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.45
2019	3	-	1,013	11.65	15.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.44

2019	4	-	630	11.65	15.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.59
2019	5	-	398	11.65	15.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.68
2019	6	27	260	11.65	15.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2019	7	177	39	11.65	15.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.58
2019	8	361	-	11.65	15.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.47
2019	9	256	4	11.65	15.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.58
2019	10	42	255	11.65	15.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.69
2019	11	-	737	11.65	15.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.58
2019	12	-	834	11.65	16.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2020	1	-	995	11.66	16.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2020	2	-	947	11.66	16.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.45
2020	3	0	769	11.66	16.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2020	4	0	602	11.66	16.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2020	5	6	413	11.66	16.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2020	6	66	133	11.66	16.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2020	7	246	14	11.66	16.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2020	8	318	4	11.66	16.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.50
2020	9	186	35	11.66	16.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2020	10	31	249	11.66	16.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2020	11	2	562	11.67	16.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2020	12	-	853	11.67	17.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2021	1	-	995	11.67	17.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2021	2	-	947	11.67	17.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.45
2021	3	0	769	11.67	17.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2021	4	0	602	11.67	17.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2021	5	6	413	11.67	17.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2021	6	66	133	11.67	17.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2021	7	246	14	11.67	17.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2021	8	318	4	11.68	17.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2021	9	186	35	11.68	17.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2021	10	31	249	11.68	17.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2021	11	2	562	11.68	17.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2021	12	-	853	11.68	18.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2022	1	-	995	11.68	18.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2022	2	-	947	11.68	18.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.46

2022	3	0	769	11.68	18.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2022	4	0	602	11.68	18.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2022	5	6	413	11.69	18.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2022	6	66	133	11.69	18.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2022	7	246	14	11.69	18.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2022	8	318	4	11.69	18.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2022	9	186	35	11.69	18.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2022	10	31	249	11.69	18.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2022	11	2	562	11.69	18.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2022	12	-	853	11.69	19.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2023	1	-	995	11.70	19.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2023	2	-	947	11.70	19.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.46
2023	3	0	769	11.70	19.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2023	4	0	602	11.70	19.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2023	5	6	413	11.70	19.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2023	6	66	133	11.70	19.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2023	7	246	14	11.70	19.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2023	8	318	4	11.70	19.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2023	9	186	35	11.71	19.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2023	10	31	249	11.71	19.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2023	11	2	562	11.71	19.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2023	12	-	853	11.71	20.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2024	1	-	995	11.71	20.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2024	2	-	947	11.71	20.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.46
2024	3	0	769	11.71	20.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2024	4	0	602	11.72	20.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2024	5	6	413	11.72	20.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2024	6	66	133	11.72	20.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2024	7	246	14	11.72	20.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2024	8	318	4	11.72	20.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2024	9	186	35	11.72	20.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2024	10	31	249	11.72	20.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2024	11	2	562	11.72	20.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2024	12	-	853	11.73	21.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2025	1	-	995	11.73	21.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34

2025	2	-	947	11.73	21.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.46
2025	3	0	769	11.73	21.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2025	4	0	602	11.73	21.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2025	5	6	413	11.73	21.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2025	6	66	133	11.73	21.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2025	7	246	14	11.74	21.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2025	8	318	4	11.74	21.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2025	9	186	35	11.74	21.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2025	10	31	249	11.74	21.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2025	11	2	562	11.74	21.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2025	12	-	853	11.74	22.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2026	1	-	995	11.74	22.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2026	2	-	947	11.75	22.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.46
2026	3	0	769	11.75	22.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2026	4	0	602	11.75	22.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2026	5	6	413	11.75	22.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2026	6	66	133	11.75	22.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2026	7	246	14	11.75	22.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2026	8	318	4	11.75	22.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2026	9	186	35	11.75	22.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2026	10	31	249	11.76	22.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2026	11	2	562	11.76	22.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2026	12	-	853	11.76	23.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2027	1	-	995	11.76	23.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2027	2	-	947	11.76	23.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.45
2027	3	0	769	11.76	23.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2027	4	0	602	11.76	23.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2027	5	6	413	11.77	23.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2027	6	66	133	11.77	23.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2027	7	246	14	11.77	23.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2027	8	318	4	11.77	23.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2027	9	186	35	11.77	23.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2027	10	31	249	11.77	23.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2027	11	2	562	11.77	23.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2027	12	-	853	11.77	24.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43

2028	1	-	995	11.78	24.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2028	2	-	947	11.78	24.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.45
2028	3	0	769	11.78	24.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2028	4	0	602	11.78	24.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2028	5	6	413	11.78	24.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2028	6	66	133	11.78	24.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2028	7	246	14	11.78	24.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2028	8	318	4	11.79	24.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.50
2028	9	186	35	11.79	24.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2028	10	31	249	11.79	24.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2028	11	2	562	11.79	24.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2028	12	-	853	11.79	25.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2029	1	-	995	11.79	25.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2029	2	-	947	11.79	25.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.45
2029	3	0	769	11.80	25.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2029	4	0	602	11.80	25.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2029	5	6	413	11.80	25.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2029	6	66	133	11.80	25.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2029	7	246	14	11.80	25.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2029	8	318	4	11.80	25.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.50
2029	9	186	35	11.80	25.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2029	10	31	249	11.80	25.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2029	11	2	562	11.81	25.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2029	12	-	853	11.81	26.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2030	1	-	995	11.81	26.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2030	2	-	947	11.81	26.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.45
2030	3	0	769	11.81	26.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2030	4	0	602	11.81	26.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2030	5	6	413	11.81	26.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2030	6	66	133	11.81	26.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2030	7	246	14	11.82	26.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2030	8	318	4	11.82	26.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.50
2030	9	186	35	11.82	26.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2030	10	31	249	11.82	26.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2030	11	2	562	11.82	26.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62

2030	12	-	853	11.82	27.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2031	1	-	995	11.82	27.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2031	2	-	947	11.83	27.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.45
2031	3	0	769	11.83	27.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2031	4	0	602	11.83	27.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2031	5	6	413	11.83	27.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2031	6	66	133	11.83	27.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2031	7	246	14	11.83	27.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2031	8	318	4	11.83	27.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.50
2031	9	186	35	11.83	27.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2031	10	31	249	11.83	27.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2031	11	2	562	11.84	27.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2031	12	-	853	11.84	28.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2032	1	-	995	11.84	28.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2032	2	-	947	11.84	28.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.45
2032	3	0	769	11.84	28.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2032	4	0	602	11.84	28.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2032	5	6	413	11.84	28.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2032	6	66	133	11.85	28.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2032	7	246	14	11.85	28.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2032	8	318	4	11.85	28.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.50
2032	9	186	35	11.85	28.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2032	10	31	249	11.85	28.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2032	11	2	562	11.85	28.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2032	12	-	853	11.85	29.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2033	1	-	995	11.85	29.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2033	2	-	947	11.86	29.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.45
2033	3	0	769	11.86	29.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2033	4	0	602	11.86	29.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2033	5	6	413	11.86	29.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2033	6	66	133	11.86	29.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2033	7	246	14	11.86	29.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2033	8	318	4	11.86	29.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2033	9	186	35	11.86	29.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2033	10	31	249	11.86	29.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70

2033	11	2	562	11.87	29.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2033	12	-	853	11.87	30.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2034	1	-	995	11.87	30.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2034	2	-	947	11.87	30.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.45
2034	3	0	769	11.87	30.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2034	4	0	602	11.87	30.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2034	5	6	413	11.87	30.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2034	6	66	133	11.87	30.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2034	7	246	14	11.88	30.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2034	8	318	4	11.88	30.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2034	9	186	35	11.88	30.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2034	10	31	249	11.88	30.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2034	11	2	562	11.88	30.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2034	12	-	853	11.88	31.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2035	1	-	995	11.88	31.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2035	2	-	947	11.88	31.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.46
2035	3	0	769	11.89	31.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2035	4	0	602	11.89	31.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2035	5	6	413	11.89	31.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2035	6	66	133	11.89	31.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2035	7	246	14	11.89	31.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2035	8	318	4	11.89	31.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2035	9	186	35	11.89	31.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62
2035	10	31	249	11.89	31.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2035	11	2	562	11.89	31.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2035	12	-	853	11.90	32.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2036	1	-	995	11.90	32.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2036	2	-	947	11.90	32.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.46
2036	3	0	769	11.90	32.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2036	4	0	602	11.90	32.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2036	5	6	413	11.90	32.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2036	6	66	133	11.90	32.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2036	7	246	14	11.90	32.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2036	8	318	4	11.91	32.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2036	9	186	35	11.91	32.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.62

2036	10	31	249	11.91	32.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2036	11	2	562	11.91	32.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2036	12	-	853	11.91	33.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2037	1	-	995	11.91	33.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.34
2037	2	-	947	11.91	33.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.46
2037	3	0	769	11.91	33.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2037	4	0	602	11.92	33.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2037	5	6	413	11.92	33.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.67
2037	6	66	133	11.92	33.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2037	7	246	14	11.92	33.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.54
2037	8	318	4	11.92	33.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2037	9	186	35	11.92	33.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.63
2037	10	31	249	11.92	33.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2037	11	2	562	11.92	33.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2037	12	-	853	11.92	34.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2038	1	-	995	11.93	34.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.35
2038	2	-	947	11.93	34.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.46
2038	3	0	769	11.93	34.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2038	4	0	602	11.93	34.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2038	5	6	413	11.93	34.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.68
2038	6	66	133	11.93	34.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2038	7	246	14	11.93	34.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.55
2038	8	318	4	11.93	34.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2038	9	186	35	11.93	34.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.63
2038	10	31	249	11.93	34.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2038	11	2	562	11.94	34.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2038	12	-	853	11.94	35.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2039	1	-	995	11.94	35.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.35
2039	2	-	947	11.94	35.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.46
2039	3	0	769	11.94	35.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2039	4	0	602	11.94	35.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2039	5	6	413	11.94	35.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.68
2039	6	66	133	11.94	35.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2039	7	246	14	11.94	35.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.55
2039	8	318	4	11.95	35.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51

2039	9	186	35	11.95	35.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.63
2039	10	31	249	11.95	35.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.70
2039	11	2	562	11.95	35.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2039	12	-	853	11.95	36.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43
2040	1	-	995	11.95	36.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.35
2040	2	-	947	11.95	36.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.46
2040	3	0	769	11.95	36.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.49
2040	4	0	602	11.95	36.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.60
2040	5	6	413	11.95	36.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.68
2040	6	66	133	11.96	36.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.68
2040	7	246	14	11.96	36.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.55
2040	8	318	4	11.96	36.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.51
2040	9	186	35	11.96	36.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.63
2040	10	31	249	11.96	36.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.71
2040	11	2	562	11.96	36.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.62
2040	12	-	853	11.96	37.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.43

Schedule C-11. Cheyenne Light: Variable Statistical Values for Residential Use Per Customer Model

Cheyenne Light **Confidential Appendix C**

Cheyenne Light: Variable Statistical Values for Residential Use Per Customer Model **Schedule C-11**

Variable	Coefficient	Standard Error	P Value	R2 = 0.9132
cdd60	0.001	0.000	0.000	
hdd60	0.000	0.000	0.000	
lnincome12	0.436	0.100	0.000	
trend	-0.007	0.001	0.000	
m2	-0.101	0.013	0.000	
m3	-0.100	0.015	0.000	
m4	-0.174	0.017	0.000	
m5	-0.215	0.021	0.000	
m6	-0.204	0.027	0.000	
m7	-0.167	0.034	0.000	
m8	-0.176	0.037	0.000	
m9	-0.210	0.032	0.000	
m10	-0.224	0.025	0.000	
m11	-0.185	0.018	0.000	
m12	-0.053	0.013	0.000	
_cons	-5.518	1.152	0.000	

Schedule C-12. Cheyenne Light: Historical and Forecasted Variable Values for Residential Customer Model

Cheyenne Light **Confidential Appendix C**

Cheyenne Light: Historical and Forecasted Variable Values for Residential Customer Model **Schedule C-12**

Year	Month	lhhld_pre10	lhhld_CISplus	CISplus	ln(custs)
2005	1	3.56	0.00	0.00	10.47
2005	2	3.56	0.00	0.00	10.47
2005	3	3.56	0.00	0.00	10.47
2005	4	3.56	0.00	0.00	10.47
2005	5	3.56	0.00	0.00	10.47
2005	6	3.56	0.00	0.00	10.47
2005	7	3.56	0.00	0.00	10.47
2005	8	3.56	0.00	0.00	10.47
2005	9	3.57	0.00	0.00	10.47
2005	10	3.57	0.00	0.00	10.47
2005	11	3.57	0.00	0.00	10.47
2005	12	3.57	0.00	0.00	10.47
2006	1	3.57	0.00	0.00	10.47
2006	2	3.57	0.00	0.00	10.47
2006	3	3.57	0.00	0.00	10.47
2006	4	3.57	0.00	0.00	10.47
2006	5	3.57	0.00	0.00	10.47
2006	6	3.57	0.00	0.00	10.47
2006	7	3.57	0.00	0.00	10.47
2006	8	3.58	0.00	0.00	10.47
2006	9	3.58	0.00	0.00	10.47
2006	10	3.58	0.00	0.00	10.47
2006	11	3.58	0.00	0.00	10.47
2006	12	3.58	0.00	0.00	10.47
2007	1	3.58	0.00	0.00	10.47
2007	2	3.58	0.00	0.00	10.47
2007	3	3.58	0.00	0.00	10.47
2007	4	3.58	0.00	0.00	10.47
2007	5	3.59	0.00	0.00	10.47
2007	6	3.59	0.00	0.00	10.47
2007	7	3.59	0.00	0.00	10.47
2007	8	3.59	0.00	0.00	10.47
2007	9	3.59	0.00	0.00	10.47
2007	10	3.59	0.00	0.00	10.47
2007	11	3.59	0.00	0.00	10.47
2007	12	3.59	0.00	0.00	10.47
2008	1	3.60	0.00	0.00	10.47
2008	2	3.60	0.00	0.00	10.47
2008	3	3.60	0.00	0.00	10.47
2008	4	3.60	0.00	0.00	10.47
2008	5	3.60	0.00	0.00	10.47
2008	6	3.60	0.00	0.00	10.47
2008	7	3.60	0.00	0.00	10.47
2008	8	3.61	0.00	0.00	10.47

2008	9	3.61	0.00	0.00	10.47
2008	10	3.61	0.00	0.00	10.47
2008	11	3.61	0.00	0.00	10.47
2008	12	3.61	0.00	0.00	10.47
2009	1	3.61	0.00	0.00	10.47
2009	2	3.61	0.00	0.00	10.47
2009	3	3.61	0.00	0.00	10.47
2009	4	3.61	0.00	0.00	10.47
2009	5	3.61	0.00	0.00	10.47
2009	6	3.62	0.00	0.00	10.47
2009	7	3.62	0.00	0.00	10.47
2009	8	3.62	0.00	0.00	10.47
2009	9	3.62	0.00	0.00	10.47
2009	10	3.62	0.00	0.00	10.47
2009	11	3.62	0.00	0.00	10.47
2009	12	3.62	0.00	0.00	10.47
2010	1	0.00	3.62	1.00	10.47
2010	2	0.00	3.62	1.00	10.47
2010	3	0.00	3.62	1.00	10.47
2010	4	0.00	3.62	1.00	10.47
2010	5	0.00	3.63	1.00	10.47
2010	6	0.00	3.63	1.00	10.47
2010	7	0.00	3.63	1.00	10.47
2010	8	0.00	3.63	1.00	10.47
2010	9	0.00	3.63	1.00	10.47
2010	10	0.00	3.63	1.00	10.47
2010	11	0.00	3.63	1.00	10.47
2010	12	0.00	3.63	1.00	10.47
2011	1	0.00	3.63	1.00	10.47
2011	2	0.00	3.63	1.00	10.48
2011	3	0.00	3.64	1.00	10.48
2011	4	0.00	3.64	1.00	10.48
2011	5	0.00	3.64	1.00	10.48
2011	6	0.00	3.64	1.00	10.48
2011	7	0.00	3.64	1.00	10.48
2011	8	0.00	3.64	1.00	10.48
2011	9	0.00	3.64	1.00	10.48
2011	10	0.00	3.65	1.00	10.48
2011	11	0.00	3.65	1.00	10.48
2011	12	0.00	3.65	1.00	10.49
2012	1	0.00	3.65	1.00	10.49
2012	2	0.00	3.65	1.00	10.49
2012	3	0.00	3.65	1.00	10.49
2012	4	0.00	3.65	1.00	10.49
2012	5	0.00	3.66	1.00	10.49
2012	6	0.00	3.66	1.00	10.49
2012	7	0.00	3.66	1.00	10.49
2012	8	0.00	3.66	1.00	10.49

2012	9	0.00	3.66	1.00	10.49
2012	10	0.00	3.66	1.00	10.49
2012	11	0.00	3.66	1.00	10.49
2012	12	0.00	3.66	1.00	10.49
2013	1	0.00	3.66	1.00	10.50
2013	2	0.00	3.66	1.00	10.50
2013	3	0.00	3.67	1.00	10.50
2013	4	0.00	3.67	1.00	10.50
2013	5	0.00	3.67	1.00	10.50
2013	6	0.00	3.67	1.00	10.50
2013	7	0.00	3.67	1.00	10.50
2013	8	0.00	3.67	1.00	10.50
2013	9	0.00	3.67	1.00	10.50
2013	10	0.00	3.67	1.00	10.50
2013	11	0.00	3.67	1.00	10.50
2013	12	0.00	3.67	1.00	10.50
2014	1	0.00	3.68	1.00	10.50
2014	2	0.00	3.68	1.00	10.50
2014	3	0.00	3.68	1.00	10.51
2014	4	0.00	3.68	1.00	10.51
2014	5	0.00	3.68	1.00	10.51
2014	6	0.00	3.68	1.00	10.51
2014	7	0.00	3.68	1.00	10.51
2014	8	0.00	3.68	1.00	10.51
2014	9	0.00	3.68	1.00	10.51
2014	10	0.00	3.68	1.00	10.51
2014	11	0.00	3.69	1.00	10.51
2014	12	0.00	3.69	1.00	10.51
2015	1	0.00	3.69	1.00	10.51
2015	2	0.00	3.69	1.00	10.51
2015	3	0.00	3.69	1.00	10.51
2015	4	0.00	3.69	1.00	10.51
2015	5	0.00	3.69	1.00	10.52
2015	6	0.00	3.69	1.00	10.52
2015	7	0.00	3.70	1.00	10.52
2015	8	0.00	3.70	1.00	10.52
2015	9	0.00	3.70	1.00	10.52
2015	10	0.00	3.70	1.00	10.52
2015	11	0.00	3.70	1.00	10.52
2015	12	0.00	3.70	1.00	10.52
2016	1	0.00	3.70	1.00	10.52
2016	2	0.00	3.71	1.00	10.52
2016	3	0.00	3.71	1.00	10.52
2016	4	0.00	3.71	1.00	10.52
2016	5	0.00	3.71	1.00	10.53
2016	6	0.00	3.71	1.00	10.53
2016	7	0.00	3.71	1.00	10.53
2016	8	0.00	3.71	1.00	10.53

2016	9	0.00	3.71	1.00	10.53
2016	10	0.00	3.71	1.00	10.53
2016	11	0.00	3.72	1.00	10.53
2016	12	0.00	3.72	1.00	10.53
2017	1	0.00	3.72	1.00	10.53
2017	2	0.00	3.72	1.00	10.53
2017	3	0.00	3.72	1.00	10.53
2017	4	0.00	3.72	1.00	10.53
2017	5	0.00	3.72	1.00	10.53
2017	6	0.00	3.72	1.00	10.53
2017	7	0.00	3.72	1.00	10.53
2017	8	0.00	3.72	1.00	10.53
2017	9	0.00	3.72	1.00	10.53
2017	10	0.00	3.72	1.00	10.53
2017	11	0.00	3.72	1.00	10.53
2017	12	0.00	3.72	1.00	10.53
2018	1	0.00	3.72	1.00	10.54
2018	2	0.00	3.73	1.00	10.54
2018	3	0.00	3.73	1.00	10.54
2018	4	0.00	3.73	1.00	10.54
2018	5	0.00	3.73	1.00	10.54
2018	6	0.00	3.73	1.00	10.54
2018	7	0.00	3.73	1.00	10.54
2018	8	0.00	3.73	1.00	10.54
2018	9	0.00	3.74	1.00	10.54
2018	10	0.00	3.74	1.00	10.54
2018	11	0.00	3.74	1.00	10.55
2018	12	0.00	3.74	1.00	10.55
2019	1	0.00	3.74	1.00	10.55
2019	2	0.00	3.74	1.00	10.55
2019	3	0.00	3.74	1.00	10.55
2019	4	0.00	3.75	1.00	10.55
2019	5	0.00	3.75	1.00	10.55
2019	6	0.00	3.75	1.00	10.55
2019	7	0.00	3.75	1.00	10.55
2019	8	0.00	3.75	1.00	10.55
2019	9	0.00	3.75	1.00	10.55
2019	10	0.00	3.75	1.00	10.56
2019	11	0.00	3.75	1.00	10.56
2019	12	0.00	3.75	1.00	10.56
2020	1	0.00	3.76	1.00	10.56
2020	2	0.00	3.76	1.00	10.56
2020	3	0.00	3.76	1.00	10.56
2020	4	0.00	3.76	1.00	10.56
2020	5	0.00	3.76	1.00	10.56
2020	6	0.00	3.76	1.00	10.56
2020	7	0.00	3.76	1.00	10.56
2020	8	0.00	3.76	1.00	10.56

2020	9	0.00	3.77	1.00	10.56
2020	10	0.00	3.77	1.00	10.56
2020	11	0.00	3.77	1.00	10.57
2020	12	0.00	3.77	1.00	10.57
2021	1	0.00	3.77	1.00	10.57
2021	2	0.00	3.77	1.00	10.57
2021	3	0.00	3.77	1.00	10.57
2021	4	0.00	3.77	1.00	10.57
2021	5	0.00	3.77	1.00	10.57
2021	6	0.00	3.78	1.00	10.57
2021	7	0.00	3.78	1.00	10.57
2021	8	0.00	3.78	1.00	10.57
2021	9	0.00	3.78	1.00	10.57
2021	10	0.00	3.78	1.00	10.57
2021	11	0.00	3.78	1.00	10.57
2021	12	0.00	3.78	1.00	10.57
2022	1	0.00	3.78	1.00	10.58
2022	2	0.00	3.78	1.00	10.58
2022	3	0.00	3.78	1.00	10.58
2022	4	0.00	3.78	1.00	10.58
2022	5	0.00	3.79	1.00	10.58
2022	6	0.00	3.79	1.00	10.58
2022	7	0.00	3.79	1.00	10.58
2022	8	0.00	3.79	1.00	10.58
2022	9	0.00	3.79	1.00	10.58
2022	10	0.00	3.79	1.00	10.58
2022	11	0.00	3.79	1.00	10.58
2022	12	0.00	3.79	1.00	10.58
2023	1	0.00	3.79	1.00	10.58
2023	2	0.00	3.79	1.00	10.58
2023	3	0.00	3.79	1.00	10.58
2023	4	0.00	3.79	1.00	10.58
2023	5	0.00	3.80	1.00	10.58
2023	6	0.00	3.80	1.00	10.58
2023	7	0.00	3.80	1.00	10.59
2023	8	0.00	3.80	1.00	10.59
2023	9	0.00	3.80	1.00	10.59
2023	10	0.00	3.80	1.00	10.59
2023	11	0.00	3.80	1.00	10.59
2023	12	0.00	3.80	1.00	10.59
2024	1	0.00	3.80	1.00	10.59
2024	2	0.00	3.80	1.00	10.59
2024	3	0.00	3.80	1.00	10.59
2024	4	0.00	3.80	1.00	10.59
2024	5	0.00	3.80	1.00	10.59
2024	6	0.00	3.81	1.00	10.59
2024	7	0.00	3.81	1.00	10.59
2024	8	0.00	3.81	1.00	10.59

2024	9	0.00	3.81	1.00	10.59
2024	10	0.00	3.81	1.00	10.59
2024	11	0.00	3.81	1.00	10.59
2024	12	0.00	3.81	1.00	10.59
2025	1	0.00	3.81	1.00	10.59
2025	2	0.00	3.81	1.00	10.59
2025	3	0.00	3.81	1.00	10.59
2025	4	0.00	3.81	1.00	10.60
2025	5	0.00	3.81	1.00	10.60
2025	6	0.00	3.81	1.00	10.60
2025	7	0.00	3.81	1.00	10.60
2025	8	0.00	3.81	1.00	10.60
2025	9	0.00	3.82	1.00	10.60
2025	10	0.00	3.82	1.00	10.60
2025	11	0.00	3.82	1.00	10.60
2025	12	0.00	3.82	1.00	10.60
2026	1	0.00	3.82	1.00	10.60
2026	2	0.00	3.82	1.00	10.60
2026	3	0.00	3.82	1.00	10.60
2026	4	0.00	3.82	1.00	10.60
2026	5	0.00	3.82	1.00	10.60
2026	6	0.00	3.82	1.00	10.60
2026	7	0.00	3.82	1.00	10.60
2026	8	0.00	3.82	1.00	10.60
2026	9	0.00	3.82	1.00	10.60
2026	10	0.00	3.82	1.00	10.60
2026	11	0.00	3.82	1.00	10.60
2026	12	0.00	3.82	1.00	10.60
2027	1	0.00	3.83	1.00	10.60
2027	2	0.00	3.83	1.00	10.60
2027	3	0.00	3.83	1.00	10.61
2027	4	0.00	3.83	1.00	10.61
2027	5	0.00	3.83	1.00	10.61
2027	6	0.00	3.83	1.00	10.61
2027	7	0.00	3.83	1.00	10.61
2027	8	0.00	3.83	1.00	10.61
2027	9	0.00	3.83	1.00	10.61
2027	10	0.00	3.83	1.00	10.61
2027	11	0.00	3.83	1.00	10.61
2027	12	0.00	3.83	1.00	10.61
2028	1	0.00	3.83	1.00	10.61
2028	2	0.00	3.83	1.00	10.61
2028	3	0.00	3.83	1.00	10.61
2028	4	0.00	3.83	1.00	10.61
2028	5	0.00	3.84	1.00	10.61
2028	6	0.00	3.84	1.00	10.61
2028	7	0.00	3.84	1.00	10.61
2028	8	0.00	3.84	1.00	10.61

2028	9	0.00	3.84	1.00	10.61
2028	10	0.00	3.84	1.00	10.61
2028	11	0.00	3.84	1.00	10.61
2028	12	0.00	3.84	1.00	10.61
2029	1	0.00	3.84	1.00	10.61
2029	2	0.00	3.84	1.00	10.61
2029	3	0.00	3.84	1.00	10.61
2029	4	0.00	3.84	1.00	10.62
2029	5	0.00	3.84	1.00	10.62
2029	6	0.00	3.84	1.00	10.62
2029	7	0.00	3.84	1.00	10.62
2029	8	0.00	3.84	1.00	10.62
2029	9	0.00	3.84	1.00	10.62
2029	10	0.00	3.84	1.00	10.62
2029	11	0.00	3.85	1.00	10.62
2029	12	0.00	3.85	1.00	10.62
2030	1	0.00	3.85	1.00	10.62
2030	2	0.00	3.85	1.00	10.62
2030	3	0.00	3.85	1.00	10.62
2030	4	0.00	3.85	1.00	10.62
2030	5	0.00	3.85	1.00	10.62
2030	6	0.00	3.85	1.00	10.62
2030	7	0.00	3.85	1.00	10.62
2030	8	0.00	3.85	1.00	10.62
2030	9	0.00	3.85	1.00	10.62
2030	10	0.00	3.85	1.00	10.62
2030	11	0.00	3.85	1.00	10.62
2030	12	0.00	3.85	1.00	10.62
2031	1	0.00	3.85	1.00	10.62
2031	2	0.00	3.85	1.00	10.62
2031	3	0.00	3.85	1.00	10.62
2031	4	0.00	3.85	1.00	10.62
2031	5	0.00	3.85	1.00	10.62
2031	6	0.00	3.86	1.00	10.62
2031	7	0.00	3.86	1.00	10.62
2031	8	0.00	3.86	1.00	10.62
2031	9	0.00	3.86	1.00	10.63
2031	10	0.00	3.86	1.00	10.63
2031	11	0.00	3.86	1.00	10.63
2031	12	0.00	3.86	1.00	10.63
2032	1	0.00	3.86	1.00	10.63
2032	2	0.00	3.86	1.00	10.63
2032	3	0.00	3.86	1.00	10.63
2032	4	0.00	3.86	1.00	10.63
2032	5	0.00	3.86	1.00	10.63
2032	6	0.00	3.86	1.00	10.63
2032	7	0.00	3.86	1.00	10.63
2032	8	0.00	3.86	1.00	10.63

2032	9	0.00	3.86	1.00	10.63
2032	10	0.00	3.86	1.00	10.63
2032	11	0.00	3.86	1.00	10.63
2032	12	0.00	3.86	1.00	10.63
2033	1	0.00	3.86	1.00	10.63
2033	2	0.00	3.86	1.00	10.63
2033	3	0.00	3.87	1.00	10.63
2033	4	0.00	3.87	1.00	10.63
2033	5	0.00	3.87	1.00	10.63
2033	6	0.00	3.87	1.00	10.63
2033	7	0.00	3.87	1.00	10.63
2033	8	0.00	3.87	1.00	10.63
2033	9	0.00	3.87	1.00	10.63
2033	10	0.00	3.87	1.00	10.63
2033	11	0.00	3.87	1.00	10.63
2033	12	0.00	3.87	1.00	10.63
2034	1	0.00	3.87	1.00	10.63
2034	2	0.00	3.87	1.00	10.63
2034	3	0.00	3.87	1.00	10.63
2034	4	0.00	3.87	1.00	10.63
2034	5	0.00	3.87	1.00	10.64
2034	6	0.00	3.87	1.00	10.64
2034	7	0.00	3.87	1.00	10.64
2034	8	0.00	3.87	1.00	10.64
2034	9	0.00	3.87	1.00	10.64
2034	10	0.00	3.87	1.00	10.64
2034	11	0.00	3.87	1.00	10.64
2034	12	0.00	3.87	1.00	10.64
2035	1	0.00	3.88	1.00	10.64
2035	2	0.00	3.88	1.00	10.64
2035	3	0.00	3.88	1.00	10.64
2035	4	0.00	3.88	1.00	10.64
2035	5	0.00	3.88	1.00	10.64
2035	6	0.00	3.88	1.00	10.64
2035	7	0.00	3.88	1.00	10.64
2035	8	0.00	3.88	1.00	10.64
2035	9	0.00	3.88	1.00	10.64
2035	10	0.00	3.88	1.00	10.64
2035	11	0.00	3.88	1.00	10.64
2035	12	0.00	3.88	1.00	10.64
2036	1	0.00	3.88	1.00	10.64
2036	2	0.00	3.88	1.00	10.64
2036	3	0.00	3.88	1.00	10.64
2036	4	0.00	3.88	1.00	10.64
2036	5	0.00	3.88	1.00	10.64
2036	6	0.00	3.88	1.00	10.64
2036	7	0.00	3.88	1.00	10.64
2036	8	0.00	3.88	1.00	10.64

2036	9	0.00	3.88	1.00	10.64
2036	10	0.00	3.88	1.00	10.64
2036	11	0.00	3.88	1.00	10.64
2036	12	0.00	3.89	1.00	10.64
2037	1	0.00	3.89	1.00	10.64
2037	2	0.00	3.89	1.00	10.65
2037	3	0.00	3.89	1.00	10.65
2037	4	0.00	3.89	1.00	10.65
2037	5	0.00	3.89	1.00	10.65
2037	6	0.00	3.89	1.00	10.65
2037	7	0.00	3.89	1.00	10.65
2037	8	0.00	3.89	1.00	10.65
2037	9	0.00	3.89	1.00	10.65
2037	10	0.00	3.89	1.00	10.65
2037	11	0.00	3.89	1.00	10.65
2037	12	0.00	3.89	1.00	10.65
2038	1	0.00	3.89	1.00	10.65
2038	2	0.00	3.89	1.00	10.65
2038	3	0.00	3.89	1.00	10.65
2038	4	0.00	3.89	1.00	10.65
2038	5	0.00	3.89	1.00	10.65
2038	6	0.00	3.89	1.00	10.65
2038	7	0.00	3.89	1.00	10.65
2038	8	0.00	3.89	1.00	10.65
2038	9	0.00	3.89	1.00	10.65
2038	10	0.00	3.90	1.00	10.65
2038	11	0.00	3.90	1.00	10.65
2038	12	0.00	3.90	1.00	10.65
2039	1	0.00	3.90	1.00	10.65
2039	2	0.00	3.90	1.00	10.65
2039	3	0.00	3.90	1.00	10.65
2039	4	0.00	3.90	1.00	10.65
2039	5	0.00	3.90	1.00	10.65
2039	6	0.00	3.90	1.00	10.65
2039	7	0.00	3.90	1.00	10.65
2039	8	0.00	3.90	1.00	10.65
2039	9	0.00	3.90	1.00	10.65
2039	10	0.00	3.90	1.00	10.66
2039	11	0.00	3.90	1.00	10.66
2039	12	0.00	3.90	1.00	10.66
2040	1	0.00	3.90	1.00	10.66
2040	2	0.00	3.90	1.00	10.66
2040	3	0.00	3.90	1.00	10.66
2040	4	0.00	3.90	1.00	10.66
2040	5	0.00	3.90	1.00	10.66
2040	6	0.00	3.91	1.00	10.66
2040	7	0.00	3.91	1.00	10.66
2040	8	0.00	3.91	1.00	10.66

2040	9	0.00	3.91	1.00	10.66
2040	10	0.00	3.91	1.00	10.66
2040	11	0.00	3.91	1.00	10.66
2040	12	0.00	3.91	1.00	10.66

Schedule C-13. Cheyenne Light: Variable Statistical Values for Residential Customer Model

Cheyenne Light **Confidential Appendix C**

Cheyenne Light: Variable Statistical Values for Residential Customer Model **Schedule C-13**

Variable	Coefficient	Standard Error	P Value	R2 = 0.9999
lhhld_pre10	-0.081	0.057	0.152	
lhhld_CISplus	0.673	0.022	0.000	
CISplus	-2.733	0.239	0.000	
_cons	10.761	0.203	0.000	

Schedule C-14. Cheyenne Light: Historical and Forecasted Variable Values for Commercial No Demand Use Per Customer Model

Cheyenne Light **Confidential Appendix C**

Cheyenne Light: Historical and Forecasted Variable Values for Commercial No Demand Use Per Customer Model **Schedule C-14**

Year	Month	cdd60	hdd60	trend	m1	m2	m3	m4	m5	m6	m7	m8	m9	m10	m11	m12	ln(upc)
2010	1	-	1,020	6.08	1	-	-	-	-	-	-	-	-	-	-	-	0.14
2010	2	-	988	6.17	-	1	-	-	-	-	-	-	-	-	-	-	0.09
2010	3	-	858	6.25	-	-	1	-	-	-	-	-	-	-	-	-	0.06
2010	4	-	651	6.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.02
2010	5	-	551	6.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.07
2010	6	46	136	6.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.11
2010	7	176	11	6.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.02
2010	8	307	-	6.67	-	-	-	-	-	-	-	1	-	-	-	-	0.05
2010	9	186	22	6.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.05
2010	10	49	105	6.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.11
2010	11	-	544	6.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.07
2010	12	-	834	7.00	-	-	-	-	-	-	-	-	-	-	-	1	0.08
2011	1	-	1,062	7.08	1	-	-	-	-	-	-	-	-	-	-	-	0.14
2011	2	-	1,079	7.17	-	1	-	-	-	-	-	-	-	-	-	-	0.10
2011	3	-	769	7.25	-	-	1	-	-	-	-	-	-	-	-	-	0.04
2011	4	-	570	7.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.04
2011	5	1	509	7.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.08
2011	6	35	203	7.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.11
2011	7	197	20	7.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.02
2011	8	342	-	7.67	-	-	-	-	-	-	-	1	-	-	-	-	0.05
2011	9	211	52	7.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.05
2011	10	50	169	7.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.11
2011	11	-	690	7.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.06
2011	12	-	928	8.00	-	-	-	-	-	-	-	-	-	-	-	1	0.09
2012	1	-	861	8.08	1	-	-	-	-	-	-	-	-	-	-	-	0.11
2012	2	-	1,003	8.17	-	1	-	-	-	-	-	-	-	-	-	-	0.08
2012	3	-	752	8.25	-	-	1	-	-	-	-	-	-	-	-	-	0.03
2012	4	-	369	8.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.08
2012	5	11	268	8.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.12
2012	6	90	80	8.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.11
2012	7	330	4	8.58	-	-	-	-	-	-	1	-	-	-	-	-	0.03

2012	8	372	-	8.67	-	-	-	-	-	-	-	1	-	-	-	-	0.06
2012	9	208	21	8.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.06
2012	10	12	269	8.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.12
2012	11	-	558	8.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.08
2012	12	-	670	9.00	-	-	-	-	-	-	-	-	-	-	-	1	0.05
2013	1	-	1,201	9.08	1	-	-	-	-	-	-	-	-	-	-	-	0.15
2013	2	-	876	9.17	-	1	-	-	-	-	-	-	-	-	-	-	0.05
2013	3	-	815	9.25	-	-	1	-	-	-	-	-	-	-	-	-	0.03
2013	4	-	814	9.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.03
2013	5	20	554	9.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.08
2013	6	86	94	9.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.12
2013	7	313	-	9.58	-	-	-	-	-	-	1	-	-	-	-	-	0.01
2013	8	222	-	9.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.01
2013	9	304	15	9.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.03
2013	10	21	283	9.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.12
2013	11	-	607	9.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.09
2013	12	-	1,010	10.00	-	-	-	-	-	-	-	-	-	-	-	1	0.08
2014	1	-	908	10.08	1	-	-	-	-	-	-	-	-	-	-	-	0.10
2014	2	-	1,125	10.17	-	1	-	-	-	-	-	-	-	-	-	-	0.08
2014	3	-	752	10.25	-	-	1	-	-	-	-	-	-	-	-	-	0.01
2014	4	-	635	10.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.06
2014	5	1	414	10.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.12
2014	6	34	91	10.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.15
2014	7	183	6	10.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.05
2014	8	271	2	10.67	-	-	-	-	-	-	-	1	-	-	-	-	0.00
2014	9	117	77	10.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.10
2014	10	78	146	10.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.12
2014	11	3	557	10.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.10
2014	12	-	717	11.00	-	-	-	-	-	-	-	-	-	-	-	1	0.04
2015	1	-	1,124	11.08	1	-	-	-	-	-	-	-	-	-	-	-	0.12
2015	2	-	643	11.17	-	1	-	-	-	-	-	-	-	-	-	-	0.01
2015	3	3	862	11.25	-	-	1	-	-	-	-	-	-	-	-	-	0.02
2015	4	-	453	11.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.09
2015	5	-	436	11.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.12
2015	6	50	186	11.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.14

2015	7	229	11	11.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.04
2015	8	308	-	11.67	-	-	-	-	-	-	-	1	-	-	-	-	0.01
2015	9	221	15	11.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.08
2015	10	66	77	11.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.15
2015	11	-	460	11.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.12
2015	12	-	870	12.00	-	-	-	-	-	-	-	-	-	-	-	1	0.05
2016	1	-	1,129	12.08	1	-	-	-	-	-	-	-	-	-	-	-	0.11
2016	2	-	847	12.17	-	1	-	-	-	-	-	-	-	-	-	-	0.03
2016	3	-	552	12.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.03
2016	4	-	624	12.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.07
2016	5	1	505	12.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.12
2016	6	79	135	12.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.14
2016	7	290	-	12.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.02
2016	8	339	-	12.67	-	-	-	-	-	-	-	1	-	-	-	-	0.02
2016	9	129	50	12.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.12
2016	10	52	157	12.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.15
2016	11	4	276	12.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.15
2016	12	-	931	13.00	-	-	-	-	-	-	-	-	-	-	-	1	0.05
2017	1	-	1,051	13.08	1	-	-	-	-	-	-	-	-	-	-	-	0.10
2017	2	-	826	13.17	-	1	-	-	-	-	-	-	-	-	-	-	0.02
2017	3	-	640	13.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.02
2017	4	-	432	13.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.10
2017	5	6	375	13.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.14
2017	6	53	185	13.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.15
2017	7	258	8	13.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.04
2017	8	271	5	13.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.02
2017	9	254	1	13.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.08
2017	10	4	336	13.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.15
2017	11	4	535	13.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.12
2017	12	-	592	14.00	-	-	-	-	-	-	-	-	-	-	-	1	0.00
2018	1	-	966	14.08	1	-	-	-	-	-	-	-	-	-	-	-	0.08
2018	2	-	913	14.17	-	1	-	-	-	-	-	-	-	-	-	-	0.02
2018	3	-	832	14.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.01
2018	4	-	645	14.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.08
2018	5	1	322	14.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.16

2018	6	134	58	14.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.14
2018	7	257	18	14.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.05
2018	8	255	1	14.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.03
2018	9	192	16	14.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.11
2018	10	52	369	14.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.14
2018	11	-	585	14.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.13
2018	12	-	856	15.00	-	-	-	-	-	-	-	-	-	-	-	1	0.03
2019	1	-	893	15.08	1	-	-	-	-	-	-	-	-	-	-	-	0.06
2019	2	-	940	15.17	-	1	-	-	-	-	-	-	-	-	-	-	0.02
2019	3	-	1,013	15.25	-	-	1	-	-	-	-	-	-	-	-	-	0.01
2019	4	-	630	15.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.09
2019	5	-	398	15.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.16
2019	6	27	260	15.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.17
2019	7	177	39	15.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.08
2019	8	361	-	15.67	-	-	-	-	-	-	-	1	-	-	-	-	0.00
2019	9	256	4	15.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.09
2019	10	42	255	15.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.16
2019	11	-	737	15.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.11
2019	12	-	834	16.00	-	-	-	-	-	-	-	-	-	-	-	1	0.02
2020	1	-	995	16.08	1	-	-	-	-	-	-	-	-	-	-	-	0.07
2020	2	-	947	16.17	-	1	-	-	-	-	-	-	-	-	-	-	0.01
2020	3	0	769	16.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.03
2020	4	0	602	16.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.10
2020	5	6	413	16.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.16
2020	6	66	133	16.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.18
2020	7	246	14	16.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.07
2020	8	318	4	16.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.02
2020	9	186	35	16.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.12
2020	10	31	249	16.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.17
2020	11	2	562	16.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.14
2020	12	-	853	17.00	-	-	-	-	-	-	-	-	-	-	-	1	0.01
2021	1	-	995	17.08	1	-	-	-	-	-	-	-	-	-	-	-	0.06
2021	2	-	947	17.17	-	1	-	-	-	-	-	-	-	-	-	-	0.00
2021	3	0	769	17.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.04
2021	4	0	602	17.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.11

2021	5	6	413	17.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.17
2021	6	66	133	17.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.18
2021	7	246	14	17.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.07
2021	8	318	4	17.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.03
2021	9	186	35	17.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.13
2021	10	31	249	17.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.18
2021	11	2	562	17.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.15
2021	12	-	853	18.00	-	-	-	-	-	-	-	-	-	-	-	1	0.00
2022	1	-	995	18.08	1	-	-	-	-	-	-	-	-	-	-	-	0.05
2022	2	-	947	18.17	-	1	-	-	-	-	-	-	-	-	-	-	0.00
2022	3	0	769	18.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.04
2022	4	0	602	18.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.12
2022	5	6	413	18.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.17
2022	6	66	133	18.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.19
2022	7	246	14	18.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.08
2022	8	318	4	18.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.04
2022	9	186	35	18.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.14
2022	10	31	249	18.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.19
2022	11	2	562	18.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.16
2022	12	-	853	19.00	-	-	-	-	-	-	-	-	-	-	-	1	0.00
2023	1	-	995	19.08	1	-	-	-	-	-	-	-	-	-	-	-	0.05
2023	2	-	947	19.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.01
2023	3	0	769	19.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.05
2023	4	0	602	19.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.13
2023	5	6	413	19.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.18
2023	6	66	133	19.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.20
2023	7	246	14	19.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.09
2023	8	318	4	19.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.04
2023	9	186	35	19.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.15
2023	10	31	249	19.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.20
2023	11	2	562	19.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.16
2023	12	-	853	20.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.01
2024	1	-	995	20.08	1	-	-	-	-	-	-	-	-	-	-	-	0.04
2024	2	-	947	20.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.02
2024	3	0	769	20.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.06

2024	4	0	602	20.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.13
2024	5	6	413	20.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.19
2024	6	66	133	20.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.20
2024	7	246	14	20.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.10
2024	8	318	4	20.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.05
2024	9	186	35	20.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.15
2024	10	31	249	20.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.20
2024	11	2	562	20.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.17
2024	12	-	853	21.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.02
2025	1	-	995	21.08	1	-	-	-	-	-	-	-	-	-	-	-	0.03
2025	2	-	947	21.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.02
2025	3	0	769	21.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.07
2025	4	0	602	21.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.14
2025	5	6	413	21.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.20
2025	6	66	133	21.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.21
2025	7	246	14	21.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.10
2025	8	318	4	21.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.06
2025	9	186	35	21.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.16
2025	10	31	249	21.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.21
2025	11	2	562	21.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.18
2025	12	-	853	22.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.03
2026	1	-	995	22.08	1	-	-	-	-	-	-	-	-	-	-	-	0.02
2026	2	-	947	22.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.03
2026	3	0	769	22.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.07
2026	4	0	602	22.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.15
2026	5	6	413	22.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.20
2026	6	66	133	22.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.22
2026	7	246	14	22.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.11
2026	8	318	4	22.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.07
2026	9	186	35	22.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.17
2026	10	31	249	22.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.22
2026	11	2	562	22.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.19
2026	12	-	853	23.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.03
2027	1	-	995	23.08	1	-	-	-	-	-	-	-	-	-	-	-	0.02
2027	2	-	947	23.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.04

2027	3	0	769	23.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.08
2027	4	0	602	23.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.16
2027	5	6	413	23.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.21
2027	6	66	133	23.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.23
2027	7	246	14	23.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.12
2027	8	318	4	23.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.07
2027	9	186	35	23.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.18
2027	10	31	249	23.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.23
2027	11	2	562	23.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.19
2027	12	-	853	24.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.04
2028	1	-	995	24.08	1	-	-	-	-	-	-	-	-	-	-	-	0.01
2028	2	-	947	24.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.05
2028	3	0	769	24.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.09
2028	4	0	602	24.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.16
2028	5	6	413	24.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.22
2028	6	66	133	24.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.23
2028	7	246	14	24.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.13
2028	8	318	4	24.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.08
2028	9	186	35	24.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.18
2028	10	31	249	24.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.23
2028	11	2	562	24.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.20
2028	12	-	853	25.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.05
2029	1	-	995	25.08	1	-	-	-	-	-	-	-	-	-	-	-	0.00
2029	2	-	947	25.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.05
2029	3	0	769	25.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.09
2029	4	0	602	25.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.17
2029	5	6	413	25.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.22
2029	6	66	133	25.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.24
2029	7	246	14	25.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.13
2029	8	318	4	25.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.09
2029	9	186	35	25.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.19
2029	10	31	249	25.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.24
2029	11	2	562	25.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.21
2029	12	-	853	26.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.06
2030	1	-	995	26.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.01

2030	2	-	947	26.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.06
2030	3	0	769	26.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.10
2030	4	0	602	26.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.18
2030	5	6	413	26.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.23
2030	6	66	133	26.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.25
2030	7	246	14	26.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.14
2030	8	318	4	26.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.10
2030	9	186	35	26.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.20
2030	10	31	249	26.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.25
2030	11	2	562	26.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.22
2030	12	-	853	27.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.06
2031	1	-	995	27.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.01
2031	2	-	947	27.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.07
2031	3	0	769	27.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.11
2031	4	0	602	27.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.19
2031	5	6	413	27.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.24
2031	6	66	133	27.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.26
2031	7	246	14	27.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.15
2031	8	318	4	27.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.10
2031	9	186	35	27.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.21
2031	10	31	249	27.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.26
2031	11	2	562	27.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.22
2031	12	-	853	28.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.07
2032	1	-	995	28.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.02
2032	2	-	947	28.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.08
2032	3	0	769	28.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.12
2032	4	0	602	28.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.19
2032	5	6	413	28.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.25
2032	6	66	133	28.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.26
2032	7	246	14	28.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.16
2032	8	318	4	28.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.11
2032	9	186	35	28.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.21
2032	10	31	249	28.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.26
2032	11	2	562	28.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.23
2032	12	-	853	29.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.08

2033	1	-	995	29.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.03
2033	2	-	947	29.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.08
2033	3	0	769	29.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.12
2033	4	0	602	29.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.20
2033	5	6	413	29.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.25
2033	6	66	133	29.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.27
2033	7	246	14	29.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.16
2033	8	318	4	29.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.12
2033	9	186	35	29.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.22
2033	10	31	249	29.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.27
2033	11	2	562	29.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.24
2033	12	-	853	30.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.09
2034	1	-	995	30.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.04
2034	2	-	947	30.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.09
2034	3	0	769	30.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.13
2034	4	0	602	30.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.21
2034	5	6	413	30.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.26
2034	6	66	133	30.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.28
2034	7	246	14	30.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.17
2034	8	318	4	30.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.13
2034	9	186	35	30.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.23
2034	10	31	249	30.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.28
2034	11	2	562	30.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.25
2034	12	-	853	31.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.09
2035	1	-	995	31.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.04
2035	2	-	947	31.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.10
2035	3	0	769	31.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.14
2035	4	0	602	31.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.21
2035	5	6	413	31.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.27
2035	6	66	133	31.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.29
2035	7	246	14	31.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.18
2035	8	318	4	31.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.13
2035	9	186	35	31.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.23
2035	10	31	249	31.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.29
2035	11	2	562	31.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.25

2035	12	-	853	32.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.10
2036	1	-	995	32.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.05
2036	2	-	947	32.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.11
2036	3	0	769	32.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.15
2036	4	0	602	32.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.22
2036	5	6	413	32.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.28
2036	6	66	133	32.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.29
2036	7	246	14	32.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.19
2036	8	318	4	32.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.14
2036	9	186	35	32.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.24
2036	10	31	249	32.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.29
2036	11	2	562	32.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.26
2036	12	-	853	33.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.11
2037	1	-	995	33.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.06
2037	2	-	947	33.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.11
2037	3	0	769	33.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.15
2037	4	0	602	33.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.23
2037	5	6	413	33.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.28
2037	6	66	133	33.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.30
2037	7	246	14	33.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.19
2037	8	318	4	33.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.15
2037	9	186	35	33.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.25
2037	10	31	249	33.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.30
2037	11	2	562	33.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.27
2037	12	-	853	34.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.11
2038	1	-	995	34.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.07
2038	2	-	947	34.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.12
2038	3	0	769	34.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.16
2038	4	0	602	34.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.24
2038	5	6	413	34.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.29
2038	6	66	133	34.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.31
2038	7	246	14	34.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.20
2038	8	318	4	34.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.15
2038	9	186	35	34.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.26
2038	10	31	249	34.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.31

2038	11	2	562	34.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.28
2038	12	-	853	35.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.12
2039	1	-	995	35.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.07
2039	2	-	947	35.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.13
2039	3	0	769	35.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.17
2039	4	0	602	35.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.24
2039	5	6	413	35.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.30
2039	6	66	133	35.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.32
2039	7	246	14	35.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.21
2039	8	318	4	35.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.16
2039	9	186	35	35.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.26
2039	10	31	249	35.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.31
2039	11	2	562	35.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.28
2039	12	-	853	36.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.13
2040	1	-	995	36.08	1	-	-	-	-	-	-	-	-	-	-	-	-0.08
2040	2	-	947	36.17	-	1	-	-	-	-	-	-	-	-	-	-	-0.14
2040	3	0	769	36.25	-	-	1	-	-	-	-	-	-	-	-	-	-0.18
2040	4	0	602	36.33	-	-	-	1	-	-	-	-	-	-	-	-	-0.25
2040	5	6	413	36.42	-	-	-	-	1	-	-	-	-	-	-	-	-0.31
2040	6	66	133	36.50	-	-	-	-	-	1	-	-	-	-	-	-	-0.32
2040	7	246	14	36.58	-	-	-	-	-	-	1	-	-	-	-	-	-0.21
2040	8	318	4	36.67	-	-	-	-	-	-	-	1	-	-	-	-	-0.17
2040	9	186	35	36.75	-	-	-	-	-	-	-	-	1	-	-	-	-0.27
2040	10	31	249	36.83	-	-	-	-	-	-	-	-	-	1	-	-	-0.32
2040	11	2	562	36.92	-	-	-	-	-	-	-	-	-	-	1	-	-0.29
2040	12	-	853	37.00	-	-	-	-	-	-	-	-	-	-	-	1	-0.14

Schedule C-15. Cheyenne Light: Variable Statistical Values for Commercial No Demand Use Per Customer Model

Cheyenne Light **Confidential Appendix C**

Cheyenne Light: Variable Statistical Values for Commercial No Demand Use Per Customer Model **Schedule C-15**

Variable	Coefficient	Standard Error	P Value	R2 = 0.8650
cdd60	0.000	0.000	0.008	
hdd60	0.000	0.000	0.002	
trend	-0.007	0.003	0.010	
m2	-0.049	0.018	0.009	
m3	-0.066	0.021	0.003	
m4	-0.120	0.026	0.000	
m5	-0.151	0.031	0.000	
m6	-0.156	0.039	0.000	
m7	-0.105	0.051	0.044	
m8	-0.087	0.057	0.132	
m9	-0.139	0.048	0.005	
m10	-0.153	0.036	0.000	
m11	-0.149	0.027	0.000	
m12	-0.032	0.020	0.111	
_cons	0.058	0.051	0.252	

Schedule C-16. Cheyenne Light: Historical and Forecasted Variable Values for Commercial No Demand Customer Model

Cheyenne Light | **Confidential Appendix C**

Cheyenne Light: Historical and Forecasted Variable Values for Commercial No Demand Customer Model | **Schedule C-16**

Year	Month	lntotemp12	ln(custs)
2010	1	4.12	8.25
2010	2	4.12	8.25
2010	3	4.12	8.25
2010	4	4.12	8.25
2010	5	4.12	8.25
2010	6	4.12	8.25
2010	7	4.12	8.25
2010	8	4.12	8.25
2010	9	4.12	8.25
2010	10	4.12	8.25
2010	11	4.12	8.25
2010	12	4.12	8.25
2011	1	4.12	8.25
2011	2	4.12	8.25
2011	3	4.12	8.25
2011	4	4.12	8.25
2011	5	4.13	8.26
2011	6	4.13	8.26
2011	7	4.13	8.26
2011	8	4.13	8.26
2011	9	4.13	8.26
2011	10	4.14	8.27
2011	11	4.14	8.27
2011	12	4.14	8.27
2012	1	4.14	8.27
2012	2	4.14	8.27
2012	3	4.14	8.28
2012	4	4.14	8.28
2012	5	4.14	8.28
2012	6	4.15	8.28
2012	7	4.15	8.28
2012	8	4.15	8.28
2012	9	4.15	8.28
2012	10	4.15	8.28
2012	11	4.15	8.28
2012	12	4.15	8.29
2013	1	4.15	8.29
2013	2	4.16	8.29
2013	3	4.16	8.30
2013	4	4.16	8.30
2013	5	4.16	8.30
2013	6	4.17	8.30
2013	7	4.17	8.31
2013	8	4.17	8.31

2013	9	4.17	8.31
2013	10	4.18	8.32
2013	11	4.18	8.32
2013	12	4.18	8.32
2014	1	4.18	8.33
2014	2	4.19	8.33
2014	3	4.19	8.33
2014	4	4.19	8.33
2014	5	4.19	8.33
2014	6	4.19	8.33
2014	7	4.19	8.33
2014	8	4.19	8.33
2014	9	4.19	8.33
2014	10	4.19	8.34
2014	11	4.19	8.34
2014	12	4.19	8.34
2015	1	4.20	8.34
2015	2	4.20	8.34
2015	3	4.20	8.34
2015	4	4.20	8.34
2015	5	4.20	8.34
2015	6	4.20	8.35
2015	7	4.20	8.35
2015	8	4.20	8.35
2015	9	4.20	8.35
2015	10	4.20	8.35
2015	11	4.20	8.35
2015	12	4.20	8.35
2016	1	4.21	8.35
2016	2	4.21	8.35
2016	3	4.21	8.35
2016	4	4.21	8.36
2016	5	4.21	8.36
2016	6	4.21	8.36
2016	7	4.21	8.36
2016	8	4.21	8.36
2016	9	4.21	8.36
2016	10	4.21	8.36
2016	11	4.21	8.36
2016	12	4.21	8.36
2017	1	4.21	8.36
2017	2	4.21	8.36
2017	3	4.21	8.36
2017	4	4.21	8.36
2017	5	4.21	8.36
2017	6	4.22	8.36
2017	7	4.22	8.37
2017	8	4.22	8.37

2017	9	4.22	8.37
2017	10	4.22	8.37
2017	11	4.22	8.37
2017	12	4.22	8.37
2018	1	4.22	8.37
2018	2	4.22	8.37
2018	3	4.22	8.37
2018	4	4.22	8.37
2018	5	4.23	8.38
2018	6	4.23	8.38
2018	7	4.23	8.38
2018	8	4.23	8.38
2018	9	4.23	8.38
2018	10	4.23	8.38
2018	11	4.23	8.39
2018	12	4.23	8.39
2019	1	4.24	8.39
2019	2	4.24	8.39
2019	3	4.24	8.39
2019	4	4.24	8.39
2019	5	4.24	8.40
2019	6	4.24	8.40
2019	7	4.24	8.40
2019	8	4.24	8.40
2019	9	4.25	8.40
2019	10	4.25	8.40
2019	11	4.25	8.40
2019	12	4.25	8.41
2020	1	4.25	8.41
2020	2	4.25	8.41
2020	3	4.25	8.41
2020	4	4.25	8.41
2020	5	4.25	8.41
2020	6	4.26	8.41
2020	7	4.26	8.42
2020	8	4.26	8.42
2020	9	4.26	8.42
2020	10	4.26	8.42
2020	11	4.26	8.42
2020	12	4.26	8.42
2021	1	4.26	8.42
2021	2	4.27	8.43
2021	3	4.27	8.43
2021	4	4.27	8.43
2021	5	4.27	8.43
2021	6	4.27	8.43
2021	7	4.27	8.43
2021	8	4.27	8.43

2021	9	4.27	8.43
2021	10	4.27	8.44
2021	11	4.27	8.44
2021	12	4.28	8.44
2022	1	4.28	8.44
2022	2	4.28	8.44
2022	3	4.28	8.44
2022	4	4.28	8.44
2022	5	4.28	8.45
2022	6	4.28	8.45
2022	7	4.28	8.45
2022	8	4.28	8.45
2022	9	4.29	8.45
2022	10	4.29	8.45
2022	11	4.29	8.45
2022	12	4.29	8.45
2023	1	4.29	8.46
2023	2	4.29	8.46
2023	3	4.29	8.46
2023	4	4.29	8.46
2023	5	4.29	8.46
2023	6	4.30	8.46
2023	7	4.30	8.46
2023	8	4.30	8.46
2023	9	4.30	8.47
2023	10	4.30	8.47
2023	11	4.30	8.47
2023	12	4.30	8.47
2024	1	4.30	8.47
2024	2	4.30	8.47
2024	3	4.31	8.47
2024	4	4.31	8.48
2024	5	4.31	8.48
2024	6	4.31	8.48
2024	7	4.31	8.48
2024	8	4.31	8.48
2024	9	4.31	8.48
2024	10	4.31	8.48
2024	11	4.31	8.48
2024	12	4.31	8.48
2025	1	4.32	8.49
2025	2	4.32	8.49
2025	3	4.32	8.49
2025	4	4.32	8.49
2025	5	4.32	8.49
2025	6	4.32	8.49
2025	7	4.32	8.49
2025	8	4.32	8.50

2025	9	4.32	8.50
2025	10	4.32	8.50
2025	11	4.32	8.50
2025	12	4.33	8.50
2026	1	4.33	8.50
2026	2	4.33	8.50
2026	3	4.33	8.50
2026	4	4.33	8.51
2026	5	4.33	8.51
2026	6	4.33	8.51
2026	7	4.33	8.51
2026	8	4.33	8.51
2026	9	4.34	8.51
2026	10	4.34	8.51
2026	11	4.34	8.51
2026	12	4.34	8.51
2027	1	4.34	8.52
2027	2	4.34	8.52
2027	3	4.34	8.52
2027	4	4.34	8.52
2027	5	4.34	8.52
2027	6	4.34	8.52
2027	7	4.35	8.52
2027	8	4.35	8.53
2027	9	4.35	8.53
2027	10	4.35	8.53
2027	11	4.35	8.53
2027	12	4.35	8.53
2028	1	4.35	8.53
2028	2	4.35	8.53
2028	3	4.35	8.53
2028	4	4.35	8.54
2028	5	4.36	8.54
2028	6	4.36	8.54
2028	7	4.36	8.54
2028	8	4.36	8.54
2028	9	4.36	8.54
2028	10	4.36	8.54
2028	11	4.36	8.54
2028	12	4.36	8.54
2029	1	4.36	8.55
2029	2	4.36	8.55
2029	3	4.37	8.55
2029	4	4.37	8.55
2029	5	4.37	8.55
2029	6	4.37	8.55
2029	7	4.37	8.55
2029	8	4.37	8.55

2029	9	4.37	8.56
2029	10	4.37	8.56
2029	11	4.37	8.56
2029	12	4.37	8.56
2030	1	4.38	8.56
2030	2	4.38	8.56
2030	3	4.38	8.56
2030	4	4.38	8.56
2030	5	4.38	8.57
2030	6	4.38	8.57
2030	7	4.38	8.57
2030	8	4.38	8.57
2030	9	4.38	8.57
2030	10	4.38	8.57
2030	11	4.38	8.57
2030	12	4.39	8.57
2031	1	4.39	8.57
2031	2	4.39	8.58
2031	3	4.39	8.58
2031	4	4.39	8.58
2031	5	4.39	8.58
2031	6	4.39	8.58
2031	7	4.39	8.58
2031	8	4.39	8.58
2031	9	4.39	8.58
2031	10	4.39	8.58
2031	11	4.40	8.59
2031	12	4.40	8.59
2032	1	4.40	8.59
2032	2	4.40	8.59
2032	3	4.40	8.59
2032	4	4.40	8.59
2032	5	4.40	8.59
2032	6	4.40	8.59
2032	7	4.40	8.59
2032	8	4.40	8.60
2032	9	4.41	8.60
2032	10	4.41	8.60
2032	11	4.41	8.60
2032	12	4.41	8.60
2033	1	4.41	8.60
2033	2	4.41	8.60
2033	3	4.41	8.60
2033	4	4.41	8.60
2033	5	4.41	8.61
2033	6	4.41	8.61
2033	7	4.41	8.61
2033	8	4.41	8.61

2033	9	4.42	8.61
2033	10	4.42	8.61
2033	11	4.42	8.61
2033	12	4.42	8.61
2034	1	4.42	8.61
2034	2	4.42	8.62
2034	3	4.42	8.62
2034	4	4.42	8.62
2034	5	4.42	8.62
2034	6	4.42	8.62
2034	7	4.42	8.62
2034	8	4.43	8.62
2034	9	4.43	8.62
2034	10	4.43	8.62
2034	11	4.43	8.62
2034	12	4.43	8.63
2035	1	4.43	8.63
2035	2	4.43	8.63
2035	3	4.43	8.63
2035	4	4.43	8.63
2035	5	4.43	8.63
2035	6	4.43	8.63
2035	7	4.44	8.63
2035	8	4.44	8.63
2035	9	4.44	8.64
2035	10	4.44	8.64
2035	11	4.44	8.64
2035	12	4.44	8.64
2036	1	4.44	8.64
2036	2	4.44	8.64
2036	3	4.44	8.64
2036	4	4.44	8.64
2036	5	4.44	8.64
2036	6	4.44	8.65
2036	7	4.45	8.65
2036	8	4.45	8.65
2036	9	4.45	8.65
2036	10	4.45	8.65
2036	11	4.45	8.65
2036	12	4.45	8.65
2037	1	4.45	8.65
2037	2	4.45	8.65
2037	3	4.45	8.65
2037	4	4.45	8.66
2037	5	4.45	8.66
2037	6	4.45	8.66
2037	7	4.46	8.66
2037	8	4.46	8.66

2037	9	4.46	8.66
2037	10	4.46	8.66
2037	11	4.46	8.66
2037	12	4.46	8.66
2038	1	4.46	8.66
2038	2	4.46	8.67
2038	3	4.46	8.67
2038	4	4.46	8.67
2038	5	4.46	8.67
2038	6	4.46	8.67
2038	7	4.47	8.67
2038	8	4.47	8.67
2038	9	4.47	8.67
2038	10	4.47	8.67
2038	11	4.47	8.67
2038	12	4.47	8.67
2039	1	4.47	8.68
2039	2	4.47	8.68
2039	3	4.47	8.68
2039	4	4.47	8.68
2039	5	4.47	8.68
2039	6	4.47	8.68
2039	7	4.47	8.68
2039	8	4.48	8.68
2039	9	4.48	8.68
2039	10	4.48	8.68
2039	11	4.48	8.69
2039	12	4.48	8.69
2040	1	4.48	8.69
2040	2	4.48	8.69
2040	3	4.48	8.69
2040	4	4.48	8.69
2040	5	4.48	8.69
2040	6	4.48	8.69
2040	7	4.48	8.69
2040	8	4.49	8.70
2040	9	4.49	8.70
2040	10	4.49	8.70
2040	11	4.49	8.70
2040	12	4.49	8.70

Schedule C-17. Cheyenne Light: Variable Statistical Values for Commercial No Demand Customer Model

Cheyenne Light **Confidential Appendix C**

Cheyenne Light: Variable Statistical Values for Commercial No Demand Customer Model **Schedule C-17**

Variable	Coefficient	Standard Error	P Value	R2 = 0.7685
lntotemp12	1.225	0.096	0.000	
_cons	3.202	0.406	0.000	

Schedule C-18. Cheyenne Light: Historical and Forecasted Values for Commercial General Service Primary and Secondary Sales Model

Cheyenne Light | **Confidential Appendix C**

Cheyenne Light: Historical and Forecasted Values for Commercial General Service Primary & Secondary Sales Mode | **Schedule C-18**

Year	Month	CGSP+CGSS Sales
2010	1	45,454.45
2010	2	44,576.66
2010	3	42,363.74
2010	4	43,963.16
2010	5	43,395.63
2010	6	44,586.69
2010	7	48,263.47
2010	8	49,916.61
2010	9	45,251.94
2010	10	46,207.56
2010	11	45,733.36
2010	12	47,673.55
2011	1	46,955.41
2011	2	44,853.29
2011	3	45,622.66
2011	4	45,109.91
2011	5	41,145.02
2011	6	45,954.84
2011	7	47,413.24
2011	8	49,994.97
2011	9	47,332.58
2011	10	46,468.67
2011	11	47,035.12
2011	12	47,073.01
2012	1	46,205.08
2012	2	45,833.03
2012	3	46,705.05
2012	4	48,761.50
2012	5	47,531.88
2012	6	48,005.59
2012	7	50,719.40
2012	8	42,477.91
2012	9	42,315.38
2012	10	38,685.02
2012	11	38,604.93
2012	12	39,354.57
2013	1	39,842.42
2013	2	38,017.86
2013	3	39,699.73
2013	4	38,872.31
2013	5	38,908.90
2013	6	40,661.76
2013	7	42,314.52
2013	8	40,748.72

2013	9	42,521.54
2013	10	39,063.47
2013	11	35,804.93
2013	12	42,924.00
2014	1	44,078.93
2014	2	37,528.47
2014	3	40,178.64
2014	4	39,415.48
2014	5	38,728.21
2014	6	38,973.31
2014	7	40,882.31
2014	8	43,865.27
2014	9	40,695.06
2014	10	38,611.82
2014	11	36,875.17
2014	12	42,649.83
2015	1	43,895.88
2015	2	38,974.68
2015	3	41,441.26
2015	4	38,248.02
2015	5	38,783.59
2015	6	40,328.07
2015	7	41,904.09
2015	8	42,538.59
2015	9	42,170.53
2015	10	40,664.97
2015	11	37,721.24
2015	12	42,876.95
2016	1	39,695.26
2016	2	39,486.03
2016	3	40,502.18
2016	4	41,200.03
2016	5	39,139.31
2016	6	41,629.44
2016	7	40,859.99
2016	8	45,352.97
2016	9	40,589.44
2016	10	39,377.80
2016	11	38,649.58
2016	12	40,950.90
2017	1	44,001.39
2017	2	38,071.78
2017	3	42,299.43
2017	4	36,969.44
2017	5	37,757.36
2017	6	42,933.51
2017	7	41,125.29
2017	8	44,672.95

2017	9	40,264.26
2017	10	40,458.13
2017	11	36,400.19
2017	12	40,819.25
2018	1	40,002.95
2018	2	37,484.84
2018	3	41,463.57
2018	4	36,704.35
2018	5	41,037.12
2018	6	39,070.79
2018	7	41,876.53
2018	8	43,703.22
2018	9	38,569.46
2018	10	39,082.23
2018	11	37,352.77
2018	12	38,464.96
2019	1	42,319.47
2019	2	37,919.03
2019	3	38,360.43
2019	4	37,249.05
2019	5	36,973.65
2019	6	39,775.48
2019	7	40,086.43
2019	8	42,905.01
2019	9	39,765.48
2019	10	39,304.80
2019	11	36,770.46
2019	12	37,979.96
2020	1	42,319.47
2020	2	37,919.03
2020	3	38,360.43
2020	4	37,249.05
2020	5	36,973.65
2020	6	39,775.48
2020	7	40,086.43
2020	8	42,905.01
2020	9	39,765.48
2020	10	39,304.80
2020	11	36,770.46
2020	12	37,979.96
2021	1	42,319.47
2021	2	37,919.03
2021	3	38,360.43
2021	4	37,249.05
2021	5	36,973.65
2021	6	39,775.48
2021	7	40,086.43
2021	8	42,905.01

2021	9	39,765.48
2021	10	39,304.80
2021	11	36,770.46
2021	12	37,979.96
2022	1	42,319.47
2022	2	37,919.03
2022	3	38,360.43
2022	4	37,249.05
2022	5	36,973.65
2022	6	39,775.48
2022	7	40,086.43
2022	8	42,905.01
2022	9	39,765.48
2022	10	39,304.80
2022	11	36,770.46
2022	12	37,979.96
2023	1	42,319.47
2023	2	37,919.03
2023	3	38,360.43
2023	4	37,249.05
2023	5	36,973.65
2023	6	39,775.48
2023	7	40,086.43
2023	8	42,905.01
2023	9	39,765.48
2023	10	39,304.80
2023	11	36,770.46
2023	12	37,979.96
2024	1	42,319.47
2024	2	37,919.03
2024	3	38,360.43
2024	4	37,249.05
2024	5	36,973.65
2024	6	39,775.48
2024	7	40,086.43
2024	8	42,905.01
2024	9	39,765.48
2024	10	39,304.80
2024	11	36,770.46
2024	12	37,979.96
2025	1	42,319.47
2025	2	37,919.03
2025	3	38,360.43
2025	4	37,249.05
2025	5	36,973.65
2025	6	39,775.48
2025	7	40,086.43
2025	8	42,905.01

2025	9	39,765.48
2025	10	39,304.80
2025	11	36,770.46
2025	12	37,979.96
2026	1	42,319.47
2026	2	37,919.03
2026	3	38,360.43
2026	4	37,249.05
2026	5	36,973.65
2026	6	39,775.48
2026	7	40,086.43
2026	8	42,905.01
2026	9	39,765.48
2026	10	39,304.80
2026	11	36,770.46
2026	12	37,979.96
2027	1	42,319.47
2027	2	37,919.03
2027	3	38,360.43
2027	4	37,249.05
2027	5	36,973.65
2027	6	39,775.48
2027	7	40,086.43
2027	8	42,905.01
2027	9	39,765.48
2027	10	39,304.80
2027	11	36,770.46
2027	12	37,979.96
2028	1	42,319.47
2028	2	37,919.03
2028	3	38,360.43
2028	4	37,249.05
2028	5	36,973.65
2028	6	39,775.48
2028	7	40,086.43
2028	8	42,905.01
2028	9	39,765.48
2028	10	39,304.80
2028	11	36,770.46
2028	12	37,979.96
2029	1	42,319.47
2029	2	37,919.03
2029	3	38,360.43
2029	4	37,249.05
2029	5	36,973.65
2029	6	39,775.48
2029	7	40,086.43
2029	8	42,905.01

2029	9	39,765.48
2029	10	39,304.80
2029	11	36,770.46
2029	12	37,979.96
2030	1	42,319.47
2030	2	37,919.03
2030	3	38,360.43
2030	4	37,249.05
2030	5	36,973.65
2030	6	39,775.48
2030	7	40,086.43
2030	8	42,905.01
2030	9	39,765.48
2030	10	39,304.80
2030	11	36,770.46
2030	12	37,979.96
2031	1	42,319.47
2031	2	37,919.03
2031	3	38,360.43
2031	4	37,249.05
2031	5	36,973.65
2031	6	39,775.48
2031	7	40,086.43
2031	8	42,905.01
2031	9	39,765.48
2031	10	39,304.80
2031	11	36,770.46
2031	12	37,979.96
2032	1	42,319.47
2032	2	37,919.03
2032	3	38,360.43
2032	4	37,249.05
2032	5	36,973.65
2032	6	39,775.48
2032	7	40,086.43
2032	8	42,905.01
2032	9	39,765.48
2032	10	39,304.80
2032	11	36,770.46
2032	12	37,979.96
2033	1	42,319.47
2033	2	37,919.03
2033	3	38,360.43
2033	4	37,249.05
2033	5	36,973.65
2033	6	39,775.48
2033	7	40,086.43
2033	8	42,905.01

2033	9	39,765.48
2033	10	39,304.80
2033	11	36,770.46
2033	12	37,979.96
2034	1	42,319.47
2034	2	37,919.03
2034	3	38,360.43
2034	4	37,249.05
2034	5	36,973.65
2034	6	39,775.48
2034	7	40,086.43
2034	8	42,905.01
2034	9	39,765.48
2034	10	39,304.80
2034	11	36,770.46
2034	12	37,979.96
2035	1	42,319.47
2035	2	37,919.03
2035	3	38,360.43
2035	4	37,249.05
2035	5	36,973.65
2035	6	39,775.48
2035	7	40,086.43
2035	8	42,905.01
2035	9	39,765.48
2035	10	39,304.80
2035	11	36,770.46
2035	12	37,979.96
2036	1	42,319.47
2036	2	37,919.03
2036	3	38,360.43
2036	4	37,249.05
2036	5	36,973.65
2036	6	39,775.48
2036	7	40,086.43
2036	8	42,905.01
2036	9	39,765.48
2036	10	39,304.80
2036	11	36,770.46
2036	12	37,979.96
2037	1	42,319.47
2037	2	37,919.03
2037	3	38,360.43
2037	4	37,249.05
2037	5	36,973.65
2037	6	39,775.48
2037	7	40,086.43
2037	8	42,905.01

2037	9	39,765.48
2037	10	39,304.80
2037	11	36,770.46
2037	12	37,979.96
2038	1	42,319.47
2038	2	37,919.03
2038	3	38,360.43
2038	4	37,249.05
2038	5	36,973.65
2038	6	39,775.48
2038	7	40,086.43
2038	8	42,905.01
2038	9	39,765.48
2038	10	39,304.80
2038	11	36,770.46
2038	12	37,979.96
2039	1	42,319.47
2039	2	37,919.03
2039	3	38,360.43
2039	4	37,249.05
2039	5	36,973.65
2039	6	39,775.48
2039	7	40,086.43
2039	8	42,905.01
2039	9	39,765.48
2039	10	39,304.80
2039	11	36,770.46
2039	12	37,979.96
2040	1	42,319.47
2040	2	37,919.03
2040	3	38,360.43
2040	4	37,249.05
2040	5	36,973.65
2040	6	39,775.48
2040	7	40,086.43
2040	8	42,905.01
2040	9	39,765.48
2040	10	39,304.80
2040	11	36,770.46
2040	12	37,979.96

Schedule C-19. Cheyenne Light: Historical and Forecasted Values for Industrial Sales Model

Cheyenne Light **Confidential Appendix C**

Cheyenne Light: Historical and Forecasted Values for Industrial Sales Model **Schedule C-19**

Year	Month	salesNlvc With Turnarounds
2015	1	25,256.68
2015	2	23,429.57
2015	3	23,177.14
2015	4	23,949.66
2015	5	22,668.14
2015	6	24,309.07
2015	7	25,688.94
2015	8	25,882.68
2015	9	25,024.74
2015	10	25,846.92
2015	11	24,483.48
2015	12	23,246.04
2016	1	23,764.74
2016	2	21,817.02
2016	3	25,520.28
2016	4	21,872.40
2016	5	22,026.60
2016	6	23,021.04
2016	7	24,471.60
2016	8	25,300.08
2016	9	25,214.40
2016	10	25,775.10
2016	11	25,354.20
2016	12	25,449.30
2017	1	25,249.80
2017	2	23,188.62
2017	3	25,853.82
2017	4	23,991.60
2017	5	25,216.86
2017	6	25,011.24
2017	7	25,111.38
2017	8	26,163.78
2017	9	15,731.46
2017	10	18,388.26
2017	11	23,648.34
2017	12	24,728.76
2018	1	26,398.26
2018	2	24,153.12
2018	3	25,758.84
2018	4	22,773.60
2018	5	25,269.12
2018	6	25,126.02
2018	7	25,181.46

2018	8	23,975.64
2018	9	24,970.38
2018	10	26,283.90
2018	11	25,630.20
2018	12	26,699.82
2019	1	25,842.60
2019	2	24,066.84
2019	3	27,143.46
2019	4	25,998.30
2019	5	26,949.48
2019	6	24,904.08
2019	7	25,984.98
2019	8	25,153.68
2019	9	22,171.50
2019	10	15,267.72
2019	11	21,575.40
2019	12	24,681.12
2020	1	25,561.74
2020	2	25,579.20
2020	3	26,396.46
2020	4	25,476.96
2020	5	24,809.04
2020	6	24,729.50
2020	7	25,875.66
2020	8	19,637.46
2020	9	17,016.30
2020	10	17,367.78
2020	11	16,433.13
2020	12	17,164.76
2021	1	15,384.93
2021	2	14,062.13
2021	3	15,384.93
2021	4	15,066.57
2021	5	15,384.93
2021	6	3,645.54
2021	7	8,729.77
2021	8	15,568.79
2021	9	14,888.65
2021	10	15,568.79
2021	11	14,888.65
2021	12	15,568.79
2022	1	16,947.33
2022	2	15,473.33
2022	3	18,063.33
2022	4	17,658.57
2022	5	18,063.33
2022	6	17,658.57
2022	7	18,063.33

2022	8	18,247.19
2022	9	17,884.39
2022	10	18,247.19
2022	11	17,480.65
2022	12	18,247.19
2023	1	18,063.33
2023	2	16,481.33
2023	3	18,063.33
2023	4	17,658.57
2023	5	18,063.33
2023	6	17,658.57
2023	7	18,063.33
2023	8	17,030.37
2023	9	17,480.65
2023	10	18,247.19
2023	11	17,480.65
2023	12	18,247.19
2024	1	18,063.33
2024	2	17,069.95
2024	3	18,063.33
2024	4	17,658.57
2024	5	18,063.33
2024	6	17,658.57
2024	7	18,063.33
2024	8	18,247.19
2024	9	17,480.65
2024	10	18,247.19
2024	11	17,480.65
2024	12	18,247.19
2025	1	18,063.33
2025	2	16,947.55
2025	3	18,063.33
2025	4	17,658.57
2025	5	18,063.33
2025	6	6,237.54
2025	7	11,408.17
2025	8	18,247.19
2025	9	17,480.65
2025	10	18,247.19
2025	11	17,480.65
2025	12	18,247.19
2026	1	18,063.33
2026	2	17,069.95
2026	3	18,063.33
2026	4	17,658.57
2026	5	18,063.33
2026	6	17,658.57
2026	7	18,063.33

2026	8	18,247.19
2026	9	17,480.65
2026	10	18,247.19
2026	11	17,480.65
2026	12	18,247.19
2027	1	18,063.33
2027	2	17,069.95
2027	3	18,063.33
2027	4	17,658.57
2027	5	18,063.33
2027	6	17,658.57
2027	7	18,063.33
2027	8	18,247.19
2027	9	17,480.65
2027	10	18,247.19
2027	11	17,480.65
2027	12	18,247.19
2028	1	18,063.33
2028	2	17,069.95
2028	3	18,063.33
2028	4	17,658.57
2028	5	18,063.33
2028	6	17,658.57
2028	7	18,063.33
2028	8	18,247.19
2028	9	17,480.65
2028	10	18,247.19
2028	11	17,480.65
2028	12	18,247.19
2029	1	18,063.33
2029	2	17,069.95
2029	3	18,063.33
2029	4	17,658.57
2029	5	18,063.33
2029	6	17,658.57
2029	7	18,063.33
2029	8	18,247.19
2029	9	17,480.65
2029	10	18,247.19
2029	11	17,480.65
2029	12	18,247.19
2030	1	18,063.33
2030	2	17,069.95
2030	3	18,063.33
2030	4	17,658.57
2030	5	18,063.33
2030	6	17,658.57
2030	7	18,063.33

2030	8	18,247.19
2030	9	17,480.65
2030	10	18,247.19
2030	11	17,480.65
2030	12	18,247.19
2031	1	18,063.33
2031	2	17,069.95
2031	3	18,063.33
2031	4	17,658.57
2031	5	18,063.33
2031	6	17,658.57
2031	7	18,063.33
2031	8	18,247.19
2031	9	17,480.65
2031	10	18,247.19
2031	11	17,480.65
2031	12	18,247.19
2032	1	18,063.33
2032	2	17,069.95
2032	3	18,063.33
2032	4	17,658.57
2032	5	18,063.33
2032	6	17,658.57
2032	7	18,063.33
2032	8	18,247.19
2032	9	17,480.65
2032	10	18,247.19
2032	11	17,480.65
2032	12	18,247.19
2033	1	18,063.33
2033	2	17,069.95
2033	3	18,063.33
2033	4	17,658.57
2033	5	18,063.33
2033	6	17,658.57
2033	7	18,063.33
2033	8	18,247.19
2033	9	17,480.65
2033	10	18,247.19
2033	11	17,480.65
2033	12	18,247.19
2034	1	18,063.33
2034	2	17,069.95
2034	3	18,063.33
2034	4	17,658.57
2034	5	18,063.33
2034	6	17,658.57
2034	7	18,063.33

2034	8	18,247.19
2034	9	17,480.65
2034	10	18,247.19
2034	11	17,480.65
2034	12	18,247.19
2035	1	18,063.33
2035	2	17,069.95
2035	3	18,063.33
2035	4	17,658.57
2035	5	18,063.33
2035	6	17,658.57
2035	7	18,063.33
2035	8	18,247.19
2035	9	17,480.65
2035	10	18,247.19
2035	11	17,480.65
2035	12	18,247.19
2036	1	18,063.33
2036	2	17,069.95
2036	3	18,063.33
2036	4	17,658.57
2036	5	18,063.33
2036	6	17,658.57
2036	7	18,063.33
2036	8	18,247.19
2036	9	17,480.65
2036	10	18,247.19
2036	11	17,480.65
2036	12	18,247.19
2037	1	18,063.33
2037	2	17,069.95
2037	3	18,063.33
2037	4	17,658.57
2037	5	18,063.33
2037	6	17,658.57
2037	7	18,063.33
2037	8	18,247.19
2037	9	17,480.65
2037	10	18,247.19
2037	11	17,480.65
2037	12	18,247.19
2038	1	18,063.33
2038	2	17,069.95
2038	3	18,063.33
2038	4	17,658.57
2038	5	18,063.33
2038	6	17,658.57
2038	7	18,063.33

2038	8	18,247.19
2038	9	17,480.65
2038	10	18,247.19
2038	11	17,480.65
2038	12	18,247.19
2039	1	18,063.33
2039	2	17,069.95
2039	3	18,063.33
2039	4	17,658.57
2039	5	18,063.33
2039	6	17,658.57
2039	7	18,063.33
2039	8	18,247.19
2039	9	17,480.65
2039	10	18,247.19
2039	11	17,480.65
2039	12	18,247.19
2040	1	18,063.33
2040	2	17,069.95
2040	3	18,063.33
2040	4	17,658.57
2040	5	18,063.33
2040	6	17,658.57
2040	7	18,063.33
2040	8	18,247.19
2040	9	17,480.65
2040	10	18,247.19
2040	11	17,480.65
2040	12	18,247.19

BLACK HILLS POWER LOAD FORECAST DATA

Schedule C-1. Black Hills Power: Monthly Historic Demand (MW)

Black Hills Power **Confidential Appendix C**

Black Hills Power: Monthly Historic Demand (MW) **Schedule C-1**

Year	Month	System Demand (MW)
2010	1	300
2010	2	291
2010	3	254
2010	4	235
2010	5	255
2010	6	304
2010	7	316
2010	8	316
2010	9	261
2010	10	245
2010	11	290
2010	12	301
2011	1	329
2011	2	315
2011	3	284
2011	4	229
2011	5	236
2011	6	321
2011	7	374
2011	8	351
2011	9	271
2011	10	251
2011	11	267
2011	12	281
2012	1	294
2012	2	277
2012	3	241
2012	4	239
2012	5	259
2012	6	360
2012	7	366
2012	8	367
2012	9	300
2012	10	251
2012	11	269
2012	12	290
2013	1	293
2013	2	285
2013	3	292
2013	4	264
2013	5	257
2013	6	309
2013	7	331
2013	8	345

2013	9	329
2013	10	263
2013	11	288
2013	12	324
2014	1	320
2014	2	309
2014	3	307
2014	4	258
2014	5	298
2014	6	294
2014	7	338
2014	8	337
2014	9	297
2014	10	239
2014	11	306
2014	12	311
2015	1	316
2015	2	301
2015	3	297
2015	4	248
2015	5	251
2015	6	321
2015	7	335
2015	8	350
2015	9	331
2015	10	252
2015	11	299
2015	12	297
2016	1	294
2016	2	273
2016	3	256
2016	4	245
2016	5	236
2016	6	336
2016	7	359
2016	8	353
2016	9	287
2016	10	244
2016	11	276
2016	12	307
2017	1	324
2017	2	305
2017	3	289
2017	4	253
2017	5	236
2017	6	316
2017	7	362
2017	8	315

2017	9	309
2017	10	264
2017	11	280
2017	12	319
2018	1	321
2018	2	311
2018	3	276
2018	4	275
2018	5	283
2018	6	337
2018	7	352
2018	8	328
2018	9	278
2018	10	255
2018	11	264
2018	12	310
2019	1	297
2019	2	331
2019	3	304
2019	4	260
2019	5	263
2019	6	306
2019	7	340
2019	8	345
2019	9	314
2019	10	293
2019	11	295
2019	12	276

** Shown are the monthly aggregations that are from the hourly data that was used in the economet*

Schedule C-2. Black Hills Power: Monthly Historic Class Sales Data

Black Hills Power **Confidential Appendix C**

Black Hills Power: Monthly Historic Class Sales Data **Schedule C-2**

Year	Month	Residential (MWh)	Commercial (MWh)	Municipal (MWh)	Industrial (MWh)
1999	1		47,131.82	1,033.37	41,218.43
1999	2		43,774.99	977.66	37,275.32
1999	3		46,328.53	1,017.10	40,588.91
1999	4		42,981.93	944.67	41,026.47
1999	5		41,064.68	836.07	43,757.67
1999	6		46,981.95	1,149.80	45,742.55
1999	7		51,782.75	1,648.35	46,120.25
1999	8		57,356.78	1,661.37	46,553.34
1999	9		52,152.24	1,500.06	46,399.03
1999	10		44,205.55	1,153.08	46,795.32
1999	11		41,275.99	1,030.15	43,307.23
1999	12		49,249.14	1,017.19	42,288.18
2000	1		46,284.43	1,069.55	40,208.91
2000	2		43,650.30	992.14	39,588.19
2000	3		48,397.72	1,049.37	43,474.63
2000	4		42,851.27	1,039.34	37,714.97
2000	5		43,907.70	1,038.73	46,109.26
2000	6		50,255.55	1,700.27	44,351.10
2000	7		51,322.88	1,671.17	42,192.43
2000	8		60,028.36	2,209.48	45,951.34
2000	9		55,674.67	1,948.16	43,328.29
2000	10		46,942.62	1,229.16	42,587.86
2000	11		44,281.70	1,036.58	42,788.99
2000	12		49,164.16	1,087.21	41,757.20
2001	1		52,484.44	1,222.41	43,452.02
2001	2		48,769.14	1,035.59	39,861.78
2001	3		46,574.03	1,038.24	38,381.74
2001	4		44,909.02	1,106.04	40,342.90
2001	5		45,506.01	1,305.53	41,963.78
2001	6		49,401.38	1,470.97	45,023.28
2001	7		56,452.60	1,925.79	46,189.08
2001	8		60,735.77	2,131.35	44,714.34
2001	9		55,707.93	1,653.99	44,508.61
2001	10		47,419.49	1,251.74	40,802.96
2001	11		44,946.00	1,046.17	44,162.79
2001	12		49,806.83	1,048.37	39,452.56
2002	1		50,549.78	1,165.63	38,508.11
2002	2		46,405.86	1,049.43	31,687.23
2002	3		49,497.02	1,043.11	34,500.93
2002	4		47,685.45	1,064.28	31,917.90
2002	5		48,672.69	1,165.34	37,741.79
2002	6		49,972.78	1,738.04	34,315.25
2002	7		63,947.49	2,797.13	34,733.84

2002	8		61,797.73	2,051.56	36,249.71
2002	9		55,800.83	1,594.31	31,511.55
2002	10		48,444.22	1,124.95	34,650.14
2002	11		46,994.01	907.67	35,170.60
2002	12		50,897.53	1,104.64	32,943.43
2003	1		54,496.06	1,106.39	33,309.92
2003	2		48,998.46	986.11	31,290.40
2003	3		49,978.51	926.48	30,890.94
2003	4		47,138.82	970.74	30,823.92
2003	5		47,668.50	1,132.68	33,349.74
2003	6		49,491.08	1,642.12	34,074.50
2003	7		61,466.08	2,370.57	36,414.91
2003	8		67,730.04	2,611.89	35,374.56
2003	9		58,358.47	2,009.29	35,652.02
2003	10		51,013.17	1,387.14	34,466.26
2003	11		49,166.64	1,144.82	34,135.48
2003	12		56,273.17	1,039.66	34,557.88
2004	1		49,750.29	1,314.54	30,239.86
2004	2		51,454.63	1,080.48	33,017.32
2004	3		51,400.32	1,069.45	35,263.90
2004	4		48,286.72	1,178.73	30,389.59
2004	5		46,637.94	1,469.71	32,751.52
2004	6		50,876.75	1,975.30	35,604.09
2004	7		60,544.42	2,186.93	37,892.38
2004	8		61,373.04	2,485.91	36,670.68
2004	9		54,017.89	1,866.56	36,047.49
2004	10		52,754.78	1,694.55	35,031.32
2004	11		46,626.57	1,190.78	34,350.33
2004	12		53,602.57	1,323.96	28,951.03
2005	1		55,853.01	1,263.90	31,059.60
2005	2		50,305.70	1,261.79	33,542.49
2005	3		51,359.06	1,122.42	33,796.01
2005	4		48,250.10	1,415.93	31,726.75
2005	5		46,611.12	1,532.85	35,640.61
2005	6		57,782.78	1,737.10	36,327.14
2005	7		61,970.14	2,647.90	35,807.14
2005	8		67,042.96	2,478.60	37,503.83
2005	9		59,468.05	2,198.78	35,134.80
2005	10		51,956.67	1,581.84	35,845.84
2005	11		48,419.35	1,176.57	34,736.40
2005	12		56,056.75	1,389.17	36,507.28
2006	1		54,408.17	1,408.14	35,519.68
2006	2		49,257.40	1,298.47	32,984.10
2006	3		54,927.88	1,436.10	34,523.30
2006	4		49,346.02	1,309.16	33,745.93
2006	5		48,898.36	1,692.78	37,345.62
2006	6		59,800.74	2,434.31	37,241.50
2006	7		67,304.67	2,932.77	37,034.08

2006	8		65,603.43	2,975.80	37,579.79
2006	9		58,552.21	2,079.63	36,259.38
2006	10		53,754.96	1,834.62	37,942.99
2006	11		51,538.49	1,449.41	38,676.66
2006	12		53,828.10	1,523.74	34,166.13
2007	1	55,217.46	58,214.91	1,546.89	33,852.03
2007	2	53,587.63	56,460.28	1,508.29	31,703.26
2007	3	43,931.10	51,418.97	1,366.97	33,698.72
2007	4	38,116.25	50,037.15	1,402.01	35,934.45
2007	5	34,119.41	51,840.14	1,889.00	36,872.91
2007	6	34,551.82	58,604.24	2,286.76	37,196.73
2007	7	46,857.58	65,602.23	3,107.39	39,040.63
2007	8	51,955.54	73,117.99	2,868.70	37,753.20
2007	9	37,483.54	60,518.75	2,432.01	35,746.52
2007	10	31,930.61	51,624.38	2,118.95	36,463.38
2007	11	37,862.83	52,549.50	1,711.73	40,140.48
2007	12	52,534.65	60,713.43	1,974.10	36,224.57
2008	1	59,346.70	60,408.50	1,852.20	35,202.32
2008	2	55,964.39	58,767.83	1,773.18	33,797.51
2008	3	47,722.93	54,282.63	1,747.42	33,669.11
2008	4	42,158.40	52,028.85	1,808.02	33,850.52
2008	5	38,906.69	55,097.60	1,956.22	36,733.71
2008	6	33,040.71	55,186.91	1,785.80	38,443.63
2008	7	39,711.45	63,582.64	2,825.46	35,197.21
2008	8	45,544.84	70,968.74	2,782.42	36,597.50
2008	9	35,631.84	61,108.88	2,389.66	35,585.41
2008	10	32,661.63	54,242.50	1,920.83	31,163.93
2008	11	41,471.48	57,044.68	1,868.29	33,289.78
2008	12	52,250.20	57,013.78	1,703.69	30,889.96
2009	1	60,085.61	60,969.97	1,774.55	30,045.24
2009	2	52,853.90	56,946.96	1,735.05	28,408.09
2009	3	50,536.19	57,339.21	1,710.98	27,530.50
2009	4	47,750.27	57,042.54	1,682.31	28,284.61
2009	5	36,632.19	49,915.99	1,690.14	32,686.97
2009	6	34,740.70	62,996.64	2,109.95	33,012.42
2009	7	36,646.05	61,129.09	2,373.45	32,576.67
2009	8	39,265.08	64,739.45	2,283.89	35,696.73
2009	9	37,354.85	61,766.52	2,999.40	32,253.64
2009	10	37,746.07	58,129.41	2,116.22	31,923.21
2009	11	41,958.23	50,943.97	1,357.67	31,456.29
2009	12	54,255.95	61,137.41	1,914.89	29,472.21
2010	1	65,825.77	65,727.23	1,678.65	33,265.82
2010	2	56,423.59	58,310.60	1,279.49	31,865.23
2010	3	53,002.93	59,173.91	1,880.62	35,109.50
2010	4	43,252.15	56,680.38	1,527.98	37,554.50
2010	5	36,765.16	50,318.82	1,611.04	35,760.59
2010	6	34,091.49	56,825.81	1,786.79	39,215.10
2010	7	39,393.55	63,854.65	2,181.04	40,097.35

2010	8	43,511.29	62,319.76	2,410.93	33,789.34
2010	9	38,969.87	66,960.65	2,085.29	33,277.37
2010	10	31,868.70	55,130.42	2,120.68	34,740.26
2010	11	36,169.01	50,843.17	1,679.62	30,696.69
2010	12	57,079.72	66,417.10	2,068.02	35,749.59
2011	1	62,917.96	59,721.45	1,876.18	30,125.30
2011	2	56,449.24	63,520.75	1,731.85	27,541.75
2011	3	55,617.42	58,847.28	1,934.65	32,636.12
2011	4	44,677.54	56,747.29	1,729.19	35,988.78
2011	5	37,655.01	53,866.65	1,456.62	32,357.62
2011	6	35,495.46	56,913.77	2,273.26	35,333.11
2011	7	41,154.91	60,049.49	2,341.89	34,372.41
2011	8	47,714.92	73,756.18	2,528.53	35,415.50
2011	9	41,205.59	62,763.08	2,555.42	36,720.86
2011	10	33,797.89	58,114.85	2,067.95	35,113.94
2011	11	41,452.83	52,475.44	1,584.53	34,773.61
2011	12	51,655.17	61,819.57	1,679.17	35,380.86
2012	1	53,928.15	60,019.83	1,654.13	35,096.41
2012	2	52,613.30	58,143.18	1,602.12	31,060.49
2012	3	49,966.32	59,725.26	1,744.91	34,087.47
2012	4	36,675.43	55,191.76	1,763.32	36,199.60
2012	5	34,688.64	56,050.31	1,980.88	33,022.69
2012	6	34,039.95	56,431.18	2,116.52	35,486.36
2012	7	48,171.61	69,148.05	3,024.11	34,350.08
2012	8	52,229.51	74,173.24	3,003.09	34,358.66
2012	9	44,076.88	69,453.14	3,084.41	35,090.33
2012	10	34,076.23	56,054.25	2,241.85	31,536.92
2012	11	41,652.45	57,789.44	1,343.07	32,437.63
2012	12	48,244.33	57,725.99	1,649.50	33,309.95
2013	1	58,940.65	63,325.61	1,982.43	32,661.49
2013	2	52,900.85	58,755.04	1,685.01	29,950.74
2013	3	51,604.01	58,463.37	1,541.67	32,563.56
2013	4	47,149.75	56,943.21	1,719.15	30,251.71
2013	5	38,909.45	54,046.84	2,189.03	37,482.97
2013	6	34,379.05	58,190.78	1,802.40	33,944.10
2013	7	42,526.45	68,183.15	2,931.44	34,285.37
2013	8	42,781.97	67,027.89	2,743.12	33,614.76
2013	9	45,592.42	69,170.19	2,519.49	34,969.98
2013	10	36,953.43	60,129.29	1,835.73	34,460.76
2013	11	41,909.58	51,446.49	1,315.37	33,536.64
2013	12	58,897.07	65,114.29	1,717.95	36,808.83
2014	1	63,670.40	65,799.87	2,116.37	33,626.07
2014	2	58,109.60	62,226.08	1,641.33	35,548.47
2014	3	54,456.15	61,262.42	1,387.38	34,492.29
2014	4	46,247.22	55,466.91	1,586.01	35,648.40
2014	5	36,792.51	54,318.70	1,569.23	33,623.44
2014	6	33,057.87	61,547.44	1,826.58	32,993.49
2014	7	37,699.51	67,637.28	2,145.33	32,304.73

2014	8	45,233.09	75,209.47	2,938.40	33,193.58
2014	9	37,827.15	69,935.00	2,168.41	31,725.83
2014	10	34,271.35	64,424.76	1,709.13	33,438.15
2014	11	37,943.86	60,232.51	1,299.76	33,504.87
2014	12	56,671.58	71,259.71	1,739.47	35,282.59
2015	1	59,798.76	69,763.71	1,594.70	33,909.60
2015	2	51,184.18	65,216.74	1,579.12	34,578.80
2015	3	50,146.51	64,713.35	1,696.67	29,372.62
2015	4	37,432.19	57,618.61	1,513.66	32,487.43
2015	5	34,841.25	60,309.90	1,562.76	33,282.04
2015	6	35,310.67	61,756.69	1,552.13	34,589.14
2015	7	42,149.93	72,444.34	1,918.38	36,024.48
2015	8	45,806.99	73,375.73	2,432.95	36,854.85
2015	9	41,732.85	69,486.14	2,356.40	36,902.05
2015	10	33,865.76	65,132.46	1,945.80	35,445.44
2015	11	35,510.60	60,627.29	1,348.09	35,433.93
2015	12	51,981.24	66,177.57	1,592.94	34,133.74
2016	1	57,877.22	66,261.04	1,690.50	35,664.89
2016	2	50,288.58	63,183.05	1,313.03	35,322.76
2016	3	44,550.29	61,366.94	1,516.97	35,045.78
2016	4	42,531.29	61,941.38	1,582.15	38,045.85
2016	5	36,881.67	56,457.76	1,522.84	32,104.57
2016	6	36,868.08	64,643.33	2,624.61	35,876.17
2016	7	46,147.14	73,027.56	2,997.41	36,688.28
2016	8	48,037.84	76,355.47	2,374.75	33,732.76
2016	9	37,917.89	65,357.81	2,688.50	37,959.14
2016	10	32,512.99	58,208.75	1,759.47	36,455.61
2016	11	33,803.58	59,904.71	1,406.66	35,638.10
2016	12	52,038.57	65,275.16	1,378.48	37,486.74
2017	1	66,283.76	69,383.01	1,732.43	36,716.91
2017	2	52,696.22	66,690.06	1,515.98	37,230.74
2017	3	46,970.12	62,580.86	1,518.02	36,368.69
2017	4	38,138.53	56,413.43	1,463.38	35,170.10
2017	5	35,706.94	59,757.51	1,562.09	33,856.11
2017	6	35,421.51	65,869.06	2,424.74	34,551.71
2017	7	45,210.95	68,634.80	2,851.08	35,254.92
2017	8	47,205.72	74,701.80	2,730.48	37,050.98
2017	9	39,375.33	69,237.14	2,522.18	38,232.54
2017	10	34,322.99	60,792.36	1,642.27	33,899.64
2017	11	39,600.49	56,965.31	1,206.22	34,250.79
2017	12	46,544.95	62,037.00	1,455.62	36,851.08
2018	1	61,187.30	68,583.18	1,441.76	36,093.96
2018	2	58,685.60	67,553.73	1,443.17	35,160.89
2018	3	53,711.43	64,183.98	1,605.95	32,988.69
2018	4	47,447.05	61,312.99	1,459.11	36,653.07
2018	5	37,420.95	59,814.78	1,481.55	36,595.14
2018	6	37,599.16	62,586.18	1,952.68	35,487.13
2018	7	43,919.15	69,728.22	2,163.15	34,261.38

2018	8	45,124.05	73,273.82	2,544.51	35,271.26
2018	9	38,321.34	64,531.14	1,717.29	32,491.88
2018	10	36,729.59	61,974.22	2,124.11	27,610.08
2018	11	40,972.54	58,071.16	1,505.13	29,192.47
2018	12	50,427.31	62,034.78	1,412.42	33,177.24
2019	1	57,426.11	68,255.77	1,680.64	39,867.48
2019	2	57,220.84	64,431.97	1,476.60	36,121.81
2019	3	61,198.94	66,109.70	1,549.10	35,702.44
2019	4	45,144.47	61,314.41	1,430.49	36,027.70
2019	5	38,316.51	57,579.20	1,502.28	36,719.93
2019	6	37,280.87	61,785.50	1,785.24	38,438.75
2019	7	41,033.80	66,508.97	1,718.90	36,376.63
2019	8	47,587.83	74,720.83	2,052.15	40,674.51
2019	9	37,793.71	63,964.29	2,148.79	40,409.74
2019	10	37,606.06	60,232.31	1,528.89	40,256.46
2019	11	44,412.56	61,756.56	1,514.67	40,598.25
2019	12	51,984.61	62,999.72	1,450.02	41,879.30

Schedule C-3. Black Hills Power: Historical and Forecasted Economic Data—Confidential

Confidential - Woods & Poole Economics **Confidential Appendix C**

2019 Data Pamphlet - Pennington, Lawrence, Weston Counties **Schedule C-3**

Black Hills Power: Historical and Forecasted Economic Data

	Woods & Poole	Woods & Poole
Year	**Total Employment (thousands of jobs)**	**Total Persoal Income (2012 $)**
1999	[redacted]	[redacted]
2000	[redacted]	[redacted]
2001	[redacted]	[redacted]
2002	[redacted]	[redacted]
2003	[redacted]	[redacted]
2004	[redacted]	[redacted]
2005	[redacted]	[redacted]
2006	[redacted]	[redacted]
2007	[redacted]	[redacted]
2008	[redacted]	[redacted]
2009	[redacted]	[redacted]
2010	[redacted]	[redacted]
2011	[redacted]	[redacted]
2012	[redacted]	[redacted]
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]

2036	[redacted]
2037	
2038	
2039	
2040	

Schedule C-4. Black Hills Power: Historical and Forecasted Weather Data Used in Demand Model

NOAA National Climatic Data Center **Confidential Appendix C**

Pennington, Lawrence, Butte, Meade, Custer, and Fall River Counties Weather Stations **Schedule C-4**

Black Hills Power: Historical and Forecasted Weather Data Used in Demand Model

Year	Month	Date	Hour	Demand Heating Degree Days	Demand Cooling Degree Days	Demand Monthly Cooling Degree Day Daily Average	Demand Monthly Heating Degree Day Daily Average
2010	1	1/6/10	18	54	0	0	35
2010	1	1/6/10	19	54	0	0	35
2010	2	2/9/10	8	55	0	0	38
2010	3	3/10/10	19	31	0	0	20
2010	4	4/6/10	11	22	0	0	13
2010	4	4/6/10	14	22	0	0	13
2010	4	4/6/10	15	22	0	0	13
2010	4	4/6/10	17	22	0	0	13
2010	5	5/28/10	15	0	14	1	9
2010	5	5/28/10	16	0	14	1	9
2010	5	5/28/10	17	0	14	1	9
2010	6	6/30/10	14	0	20	5	1
2010	6	6/30/10	16	0	20	5	1
2010	6	6/30/10	17	0	20	5	1
2010	7	7/26/10	13	0	19	11	0
2010	7	7/26/10	14	0	19	11	0
2010	7	7/26/10	15	0	19	11	0
2010	7	7/26/10	16	0	19	11	0
2010	7	7/26/10	17	0	19	11	0
2010	8	8/11/10	14	0	18	13	0
2010	8	8/11/10	16	0	18	13	0
2010	8	8/12/10	15	0	17	13	0
2010	8	8/12/10	16	0	17	13	0
2010	8	8/12/10	17	0	17	13	0
2010	9	9/9/10	14	0	13	3	2
2010	10	10/5/10	16	0	12	1	6
2010	11	11/22/10	18	54	0	0	26
2010	12	12/30/10	18	44	0	0	34
2010	12	12/31/10	18	57	0	0	34
2011	1	1/31/11	19	63	0	0	38
2011	1	1/31/11	20	63	0	0	38
2011	2	2/1/11	9	67	0	0	37
2011	2	2/1/11	10	67	0	0	37
2011	3	3/2/11	9	56	0	0	27
2011	3	3/7/11	19	53	0	0	27
2011	3	3/7/11	20	53	0	0	27
2011	4	4/14/11	11	26	0	0	16
2011	4	4/14/11	12	26	0	0	16
2011	4	4/14/11	13	26	0	0	16
2011	5	5/12/11	13	15	0	0	9
2011	6	6/29/11	15	0	21	4	1

2011	6	6/29/11	16	0	21	4	1
2011	6	6/29/11	18	0	21	4	1
2011	7	7/19/11	16	0	26	15	0
2011	8	8/1/11	14	0	22	13	0
2011	8	8/1/11	15	0	22	13	0
2011	9	9/1/11	17	0	10	4	2
2011	10	10/4/11	16	0	12	2	10
2011	11	11/19/11	18	48	0	0	23
2011	12	12/5/11	18	46	0	0	29
2011	12	12/5/11	19	46	0	0	29
2011	12	12/5/11	21	46	0	0	29
2011	12	12/6/11	8	39	0	0	29
2012	1	1/11/12	18	36	0	0	29
2012	2	2/10/12	10	48	0	0	32
2012	2	2/10/12	12	48	0	0	32
2012	2	2/10/12	20	48	0	0	32
2012	2	2/10/12	22	48	0	0	32
2012	2	2/27/12	8	39	0	0	32
2012	2	2/27/12	9	39	0	0	32
2012	3	3/1/12	20	28	0	0	11
2012	3	3/2/12	10	35	0	0	11
2012	3	3/2/12	18	35	0	0	11
2012	3	3/2/12	21	35	0	0	11
2012	4	4/24/12	15	0	12	1	9
2012	4	4/24/12	16	0	12	1	9
2012	5	5/17/12	14	0	12	2	5
2012	6	6/26/12	14	0	25	11	0
2012	6	6/26/12	15	0	25	11	0
2012	7	7/16/12	15	0	25	18	0
2012	7	7/19/12	17	0	24	18	0
2012	8	8/28/12	16	0	24	13	0
2012	9	9/1/12	16	0	24	6	0
2012	9	9/1/12	17	0	24	6	0
2012	9	9/10/12	14	0	18	6	0
2012	10	10/24/12	19	22	0	0	13
2012	11	11/11/12	18	44	0	0	21
2012	12	12/27/12	19	52	0	0	32
2013	1	1/31/13	11	50	0	0	33
2013	1	1/31/13	19	50	0	0	33
2013	2	2/19/13	10	41	0	0	29
2013	3	3/13/13	13	16	0	0	25
2013	4	4/9/13	11	44	0	0	22
2013	4	4/9/13	12	44	0	0	22
2013	4	4/9/13	13	44	0	0	22
2013	5	5/7/13	15	1	0	2	5
2013	6	6/27/13	16	0	15	6	1
2013	6	6/27/13	17	0	15	6	1
2013	7	7/11/13	16	0	22	13	0

2013	7	7/17/13	17	0	16	13	0
2013	7	7/17/13	18	0	16	13	0
2013	7	7/18/13	13	0	19	13	0
2013	7	7/18/13	14	0	19	13	0
2013	8	8/27/13	16	0	22	13	0
2013	9	9/5/13	14	0	19	7	1
2013	10	10/28/13	18	26	0	0	16
2013	10	10/28/13	19	26	0	0	16
2013	11	11/11/13	18	34	0	0	24
2013	12	12/7/13	17	71	0	0	39
2014	1	1/5/14	19	60	0	0	32
2014	2	2/4/14	19	57	0	0	41
2014	2	2/5/14	8	66	0	0	41
2014	2	2/5/14	18	66	0	0	41
2014	2	2/5/14	20	66	0	0	41
2014	2	2/6/14	19	68	0	0	41
2014	3	3/1/14	19	63	0	0	28
2014	4	4/1/14	8	41	0	0	16
2014	4	4/1/14	10	41	0	0	16
2014	5	5/29/14	16	0	15	2	7
2014	6	6/26/14	15	0	9	4	1
2014	7	7/21/14	16	0	21	11	0
2014	7	7/21/14	17	0	21	11	0
2014	8	8/13/14	15	0	15	10	0
2014	9	9/26/14	16	0	16	5	4
2014	9	9/26/14	17	0	16	5	4
2014	10	10/2/14	19	12	0	0	7
2014	10	10/3/14	8	18	0	0	7
2014	10	10/3/14	9	18	0	0	7
2014	11	11/11/14	19	53	0	0	30
2014	12	12/30/14	18	62	0	0	30
2014	12	12/30/14	19	62	0	0	30
2014	12	12/30/14	20	62	0	0	30
2015	1	1/8/15	18	31	0	0	29
2015	2	2/27/15	8	52	0	0	30
2015	3	3/3/15	22	38	0	0	16
2015	4	4/9/15	9	20	0	0	13
2015	5	5/19/15	21	18	0	0	9
2015	6	6/29/15	17	0	15	7	0
2015	7	7/23/15	16	0	18	11	0
2015	7	7/23/15	17	0	18	11	0
2015	8	8/5/15	17	0	14	11	0
2015	8	8/12/15	16	0	20	11	0
2015	9	9/2/15	16	0	18	7	0
2015	9	9/3/15	15	0	20	7	0
2015	9	9/3/15	17	0	20	7	0
2015	10	10/28/15	20	22	0	1	8
2015	10	10/29/15	8	26	0	1	8

2015	11	11/30/15	20	43	0	0	23
2015	12	12/29/15	18	53	0	0	31
2015	12	12/30/15	9	49	0	0	31
2016	1	1/8/16	10	43	0	0	31
2016	2	2/2/16	19	35	0	0	22
2016	2	2/3/16	19	36	0	0	22
2016	2	2/4/16	8	35	0	0	22
2016	3	3/23/16	12	30	0	0	18
2016	4	4/26/16	13	22	0	0	13
2016	5	5/5/16	17	0	4	1	5
2016	5	5/13/16	10	14	0	1	5
2016	5	5/19/16	15	0	1	1	5
2016	6	6/16/16	15	0	19	12	0
2016	6	6/24/16	16	0	20	12	0
2016	7	7/20/16	15	0	23	14	0
2016	7	7/20/16	16	0	23	14	0
2016	7	7/20/16	17	0	23	14	0
2016	8	8/10/16	16	0	17	11	0
2016	9	9/1/16	16	0	10	4	1
2016	9	9/1/16	17	0	10	4	1
2016	10	10/1/16	18	0	5	1	7
2016	10	10/12/16	10	22	0	1	7
2016	11	11/29/16	9	33	0	0	16
2016	12	12/8/16	18	55	0	0	40
2016	12	12/9/16	9	60	0	0	40
2016	12	12/9/16	17	60	0	0	40
2016	12	12/17/16	18	64	0	0	40
2017	1	1/6/17	9	52	0	0	38
2017	2	2/3/17	8	49	0	0	27
2017	3	3/10/17	11	41	0	0	20
2017	4	4/26/17	8	29	0	0	14
2017	5	5/12/17	15	0	3	1	5
2017	5	5/17/17	11	11	0	1	5
2017	5	5/17/17	17	11	0	1	5
2017	5	5/18/17	12	18	0	1	5
2017	6	6/9/17	17	0	18	8	0
2017	7	7/20/17	15	0	20	17	0
2017	7	7/20/17	18	0	20	17	0
2017	8	8/28/17	16	0	14	9	0
2017	8	8/28/17	17	0	14	9	0
2017	8	8/29/17	15	0	16	9	0
2017	8	8/29/17	16	0	16	9	0
2017	9	9/11/17	17	0	16	5	4
2017	10	10/31/17	9	29	0	0	10
2017	11	11/6/17	18	37	0	0	21
2017	12	12/30/17	18	64	0	0	34
2017	12	12/30/17	19	64	0	0	34
2018	1	1/15/18	20	55	0	0	33

2018	1	1/16/18	8	54	0	0	33
2018	1	1/16/18	9	54	0	0	33
2018	2	2/21/18	7	58	0	0	44
2018	3	3/5/18	18	34	0	0	27
2018	3	3/5/18	19	34	0	0	27
2018	3	3/5/18	20	34	0	0	27
2018	3	3/6/18	9	36	0	0	27
2018	4	4/6/18	9	43	0	0	20
2018	4	4/6/18	10	43	0	0	20
2018	5	5/31/18	17	0	11	4	4
2018	6	6/14/18	17	0	19	8	0
2018	7	7/10/18	17	0	21	11	0
2018	8	8/2/18	16	0	12	9	0
2018	8	8/3/18	15	0	17	9	0
2018	8	8/3/18	16	0	17	9	0
2018	8	8/10/18	16	0	18	9	0
2018	8	8/10/18	17	0	18	9	0
2018	9	9/12/18	17	0	10	5	4
2018	10	10/8/18	19	25	0	0	14
2018	11	11/9/18	8	46	0	0	26
2018	11	11/17/18	19	39	0	0	26
2018	12	12/27/18	12	44	0	0	30
2018	12	12/27/18	17	44	0	0	30
2019	1	1/18/19	11	45	0	0	32
2019	1	1/29/19	19	48	0	0	32
2019	1	1/30/19	9	50	0	0	32
2019	2	2/25/19	20	60	0	0	51
2019	3	3/3/19	20	65	0	0	31
2019	3	3/4/19	8	60	0	0	31
2019	3	3/4/19	9	60	0	0	31
2019	4	4/30/19	7	30	0	0	15
2019	4	4/30/19	8	30	0	0	15
2019	5	5/21/19	9	25	0	1	13
2019	5	5/21/19	17	25	0	1	13
2019	6	6/28/19	16	0	14	5	1
2019	6	6/28/19	17	0	14	5	1
2019	7	7/24/19	15	0	15	10	0
2019	7	7/31/19	15	0	12	10	0
2019	8	8/6/19	15	0	14	8	0
2019	9	9/2/19	16	0	15	5	2
2019	9	9/4/19	16	0	11	5	2
2019	10	10/30/19	7	44	0	0	20
2019	11	11/6/19	18	36	0	0	26
2019	12	12/9/19	8	39	0	0	28
2019	12	12/16/19	18	33	0	0	28
Forecasted Weather Normalization	1	-	-	49	0	0	33
Forecasted Weather Normalization	2	-	-	52	0	0	33
Forecasted Weather Normalization	3	-	-	41	0	0	23

Forecasted Weather Normalization	4	-	-	30	0	0	15
Forecasted Weather Normalization	5	-	-	0	10	2	6
Forecasted Weather Normalization	6	-	-	0	17	7	1
Forecasted Weather Normalization	7	-	-	0	21	14	0
Forecasted Weather Normalization	8	-	-	0	19	11	0
Forecasted Weather Normalization	9	-	-	0	15	5	2
Forecasted Weather Normalization	10	-	-	25	0	0	13
Forecasted Weather Normalization	11	-	-	40	0	0	23
Forecasted Weather Normalization	12	-	-	52	0	0	33

Schedule C-5. Black Hills Power: Historical and Forecasted Weather Data Used in Sales Models

NOAA National Climatic Data Center | **Confidential Appendix C**
Pennington, Lawrence, Butte, Meade, Custer, and Fall River Counties Weather Stations | **Schedule C-5**
Black Hills Power: Historical and Forecasted Weather Data Used in Sales Models

Year	Month	Energy Heating Degree Days	Energy Cooling Degree Days
1999	1	528.07	0.00
1999	2	855.99	0.00
1999	3	761.95	0.00
1999	4	584.65	0.00
1999	5	358.37	0.00
1999	6	77.23	48.74
1999	7	9.23	218.47
1999	8	0.00	347.16
1999	9	65.84	207.17
1999	10	212.12	28.79
1999	11	264.34	5.02
1999	12	702.67	0.00
2000	1	830.52	0.00
2000	2	970.90	0.00
2000	3	613.83	0.00
2000	4	575.06	0.00
2000	5	264.32	20.18
2000	6	74.05	111.60
2000	7	15.75	297.28
2000	8	0.00	434.14
2000	9	0.00	327.61
2000	10	294.85	65.69
2000	11	631.67	5.48
2000	12	1,061.25	0.00
2001	1	1,036.77	0.00
2001	2	1,146.54	0.00
2001	3	892.30	0.00
2001	4	669.98	0.00
2001	5	230.96	61.56
2001	6	99.83	44.17
2001	7	5.04	336.43
2001	8	0.00	474.68
2001	9	36.45	305.55
2001	10	187.32	53.27
2001	11	324.22	0.00
2001	12	787.50	0.00
2002	1	936.65	0.00
2002	2	915.17	0.00
2002	3	955.62	0.00
2002	4	793.26	5.76
2002	5	449.97	0.17
2002	6	113.88	79.68
2002	7	0.00	470.99

2002	8	0.00	437.21
2002	9	0.57	298.29
2002	10	285.67	20.39
2002	11	719.67	0.00
2002	12	681.91	0.00
2003	1	870.75	0.00
2003	2	1,086.20	0.00
2003	3	935.96	0.00
2003	4	474.74	9.56
2003	5	343.74	0.00
2003	6	91.15	74.53
2003	7	15.70	317.23
2003	8	0.00	567.83
2003	9	22.30	342.84
2003	10	183.82	32.09
2003	11	657.28	32.49
2003	12	829.91	0.00
2004	1	910.06	0.00
2004	2	1,195.92	0.00
2004	3	694.16	0.00
2004	4	378.19	0.00
2004	5	257.90	29.36
2004	6	99.94	77.39
2004	7	32.75	207.04
2004	8	3.46	334.73
2004	9	13.04	230.53
2004	10	135.50	50.46
2004	11	462.86	0.00
2004	12	736.48	0.00
2005	1	1,251.52	0.00
2005	2	743.03	0.00
2005	3	649.13	0.00
2005	4	510.12	3.87
2005	5	435.10	10.19
2005	6	78.52	58.36
2005	7	0.00	421.89
2005	8	8.30	433.00
2005	9	6.46	292.74
2005	10	194.55	59.34
2005	11	404.80	3.76
2005	12	942.82	0.00
2006	1	733.98	0.00
2006	2	811.19	0.00
2006	3	851.53	0.00
2006	4	555.06	10.13
2006	5	344.91	0.17
2006	6	12.22	227.93
2006	7	0.00	384.33

2006	8	0.00	532.33
2006	9	21.23	223.90
2006	10	293.54	31.03
2006	11	609.62	3.58
2006	12	788.44	0.00
2007	1	991.70	0.00
2007	2	1,199.85	0.00
2007	3	623.19	1.41
2007	4	587.06	0.00
2007	5	163.14	37.77
2007	6	76.48	111.09
2007	7	0.00	433.51
2007	8	0.00	581.74
2007	9	41.52	233.55
2007	10	137.85	71.56
2007	11	402.03	2.57
2007	12	951.23	0.00
2008	1	949.40	0.00
2008	2	1,268.85	0.00
2008	3	776.12	0.00
2008	4	689.60	2.90
2008	5	403.43	0.00
2008	6	136.71	27.85
2008	7	0.62	263.73
2008	8	0.23	407.08
2008	9	56.62	207.10
2008	10	175.22	90.87
2008	11	488.32	3.95
2008	12	869.28	0.00
2009	1	1,215.63	0.00
2009	2	876.40	0.00
2009	3	887.53	0.00
2009	4	683.47	2.59
2009	5	346.39	7.12
2009	6	147.31	63.71
2009	7	0.00	269.27
2009	8	0.28	287.01
2009	9	4.91	215.55
2009	10	395.84	43.57
2009	11	498.57	1.86
2009	12	971.38	0.00
2010	1	1,133.40	0.00
2010	2	1,150.60	0.00
2010	3	831.80	0.00
2010	4	472.46	0.00
2010	5	412.27	0.00
2010	6	69.30	52.60
2010	7	0.35	267.11

2010	8	0.00	409.78
2010	9	2.60	260.52
2010	10	80.17	65.67
2010	11	384.14	3.10
2010	12	1,015.83	0.00
2011	1	1,196.20	0.00
2011	2	1,071.77	0.00
2011	3	1,027.45	0.00
2011	4	560.78	0.00
2011	5	418.69	0.36
2011	6	155.62	53.04
2011	7	0.66	255.64
2011	8	0.00	469.64
2011	9	31.76	307.72
2011	10	122.56	108.73
2011	11	533.40	0.00
2011	12	913.42	0.00
2012	1	745.62	0.00
2012	2	1,024.60	0.00
2012	3	674.22	0.00
2012	4	263.28	16.33
2012	5	178.71	35.70
2012	6	80.24	168.46
2012	7	0.00	467.16
2012	8	0.00	500.17
2012	9	0.83	349.58
2012	10	183.79	33.83
2012	11	559.24	1.98
2012	12	677.64	0.00
2013	1	1,126.76	0.00
2013	2	911.64	0.00
2013	3	739.72	0.00
2013	4	806.62	0.00
2013	5	409.44	26.75
2013	6	86.11	73.84
2013	7	0.00	353.98
2013	8	0.00	319.51
2013	9	0.00	447.95
2013	10	239.09	51.90
2013	11	602.55	0.00
2013	12	1,053.22	0.00
2014	1	1,047.44	0.00
2014	2	1,187.36	0.00
2014	3	900.25	0.00
2014	4	720.17	0.00
2014	5	373.96	0.00
2014	6	64.74	71.54
2014	7	0.00	231.94

2014	8	0.00	373.24
2014	9	100.43	168.71
2014	10	124.22	100.48
2014	11	544.65	4.85
2014	12	803.18	0.00
2015	1	1,170.10	0.00
2015	2	667.65	0.00
2015	3	786.36	7.67
2015	4	399.89	0.00
2015	5	326.50	4.95
2015	6	127.90	84.30
2015	7	0.00	296.16
2015	8	0.00	405.69
2015	9	8.49	276.69
2015	10	76.14	83.99
2015	11	402.19	4.32
2015	12	813.55	0.00
2016	1	1,127.55	0.00
2016	2	847.61	0.00
2016	3	456.04	0.00
2016	4	495.44	2.19
2016	5	367.69	15.33
2016	6	32.81	175.51
2016	7	0.00	385.76
2016	8	0.00	448.44
2016	9	23.29	201.42
2016	10	130.05	50.74
2016	11	207.67	10.63
2016	12	1,011.57	0.00
2017	1	1,316.93	0.00
2017	2	927.70	0.00
2017	3	664.98	0.00
2017	4	390.00	0.34
2017	5	289.11	34.21
2017	6	106.60	151.74
2017	7	0.34	356.84
2017	8	0.00	373.98
2017	9	10.84	341.63
2017	10	262.54	8.67
2017	11	545.73	11.42
2017	12	551.59	1.72
2018	1	1,293.67	0.00
2018	2	1,120.22	0.00
2018	3	986.35	0.00
2018	4	836.30	0.00
2018	5	259.21	23.56
2018	6	29.10	241.83
2018	7	12.26	280.84

2018	8	0.00	330.30
2018	9	6.24	227.71
2018	10	407.96	18.46
2018	11	553.17	0.00
2018	12	821.67	0.00
2019	1	892.10	0.00
2019	2	1,302.18	0.00
2019	3	1,302.70	0.00
2019	4	621.43	0.00
2019	5	382.01	11.09
2019	6	204.72	69.61
2019	7	1.66	216.99
2019	8	0.00	318.42
2019	9	14.37	195.88
2019	10	308.29	50.03
2019	11	748.83	0.00
2019	12	829.12	0.00
Forecasted Weather Normalization	1	1,038.84	0.00
Forecasted Weather Normalization	2	1,013.40	0.00
Forecasted Weather Normalization	3	810.06	0.43
Forecasted Weather Normalization	4	574.65	2.56
Forecasted Weather Normalization	5	334.09	15.17
Forecasted Weather Normalization	6	93.55	98.45
Forecasted Weather Normalization	7	4.49	320.60
Forecasted Weather Normalization	8	0.58	418.38
Forecasted Weather Normalization	9	22.28	269.65
Forecasted Weather Normalization	10	211.00	53.31
Forecasted Weather Normalization	11	502.14	4.52
Forecasted Weather Normalization	12	848.27	0.08

Schedule C-6. Black Hills Power: Historical and Forecasted Variable Values for Demand Model

Black Hills Power **Confidential Appendix C**

Black Hills Power: Historical and Forecasted Variable Values for Demand Model **Schedule C-6**

Year	Month	Date	Hour	cdd60	hdd60	mnthcdd60perday	mnthhdd60perday	lntotPI	weekend	m1	m2	m3	m4	m5	m6	m7	m8	m9	m10	m11	m12	ln(mwNlvc)
2010	1	1/6/10	18	-	53.71	-	35.17	7.53	-	1	-	-	-	-	-	-	-	-	-	-	-	5.71
2010	1	1/6/10	19	-	53.71	-	35.17	7.53	-	1	-	-	-	-	-	-	-	-	-	-	-	5.71
2010	2	2/9/10	8	-	55.25	-	38.07	7.53	-	-	1	-	-	-	-	-	-	-	-	-	-	5.68
2010	3	3/10/10	19	-	31.07	-	20.39	7.53	-	-	-	1	-	-	-	-	-	-	-	-	-	5.54
2010	4	4/6/10	11	-	21.62	-	13.17	7.53	-	-	-	-	1	-	-	-	-	-	-	-	-	5.45
2010	4	4/6/10	14	-	21.62	-	13.17	7.53	-	-	-	-	1	-	-	-	-	-	-	-	-	5.45
2010	4	4/6/10	15	-	21.62	-	13.17	7.53	-	-	-	-	1	-	-	-	-	-	-	-	-	5.45
2010	4	4/6/10	17	-	21.62	-	13.17	7.53	-	-	-	-	1	-	-	-	-	-	-	-	-	5.45
2010	5	5/28/10	15	14.43	-	1.00	8.98	7.53	-	-	-	-	-	1	-	-	-	-	-	-	-	5.55
2010	5	5/28/10	16	14.43	-	1.00	8.98	7.53	-	-	-	-	-	1	-	-	-	-	-	-	-	5.55
2010	5	5/28/10	17	14.43	-	1.00	8.98	7.53	-	-	-	-	-	1	-	-	-	-	-	-	-	5.55
2010	6	6/30/10	14	19.64	-	4.97	1.03	7.53	-	-	-	-	-	-	1	-	-	-	-	-	-	5.73
2010	6	6/30/10	16	19.64	-	4.97	1.03	7.53	-	-	-	-	-	-	1	-	-	-	-	-	-	5.73
2010	6	6/30/10	17	19.64	-	4.97	1.03	7.53	-	-	-	-	-	-	1	-	-	-	-	-	-	5.73
2010	7	7/26/10	13	18.81	-	11.35	0.01	7.53	-	-	-	-	-	-	-	1	-	-	-	-	-	5.77
2010	7	7/26/10	14	18.81	-	11.35	0.01	7.53	-	-	-	-	-	-	-	1	-	-	-	-	-	5.77
2010	7	7/26/10	15	18.81	-	11.35	0.01	7.53	-	-	-	-	-	-	-	1	-	-	-	-	-	5.77
2010	7	7/26/10	16	18.81	-	11.35	0.01	7.53	-	-	-	-	-	-	-	1	-	-	-	-	-	5.77
2010	7	7/26/10	17	18.81	-	11.35	0.01	7.53	-	-	-	-	-	-	-	1	-	-	-	-	-	5.77
2010	8	8/11/10	14	18.29	-	12.91	-	7.53	-	-	-	-	-	-	-	-	1	-	-	-	-	5.79
2010	8	8/11/10	16	18.29	-	12.91	-	7.53	-	-	-	-	-	-	-	-	1	-	-	-	-	5.79
2010	8	8/12/10	15	17.40	-	12.91	-	7.53	-	-	-	-	-	-	-	-	1	-	-	-	-	5.79
2010	8	8/12/10	16	17.40	-	12.91	-	7.53	-	-	-	-	-	-	-	-	1	-	-	-	-	5.79
2010	8	8/12/10	17	17.40	-	12.91	-	7.53	-	-	-	-	-	-	-	-	1	-	-	-	-	5.79
2010	9	9/9/10	14	13.42	-	3.13	1.60	7.53	-	-	-	-	-	-	-	-	-	1	-	-	-	5.63
2010	10	10/5/10	16	11.63	-	0.95	6.42	7.53	-	-	-	-	-	-	-	-	-	-	1	-	-	5.52
2010	11	11/22/10	18	-	53.77	0.10	26.20	7.53	-	-	-	-	-	-	-	-	-	-	-	1	-	5.65
2010	12	12/30/10	18	-	44.29	-	33.86	7.53	-	-	-	-	-	-	-	-	-	-	-	-	1	5.65
2010	12	12/31/10	18	-	57.03	-	33.86	7.53	-	-	-	-	-	-	-	-	-	-	-	-	1	5.69
2011	1	1/31/11	19	-	63.03	-	37.50	7.54	-	1	-	-	-	-	-	-	-	-	-	-	-	5.75
2011	1	1/31/11	20	-	63.03	-	37.50	7.54	-	1	-	-	-	-	-	-	-	-	-	-	-	5.75
2011	2	2/1/11	9	-	66.71	-	37.15	7.54	-	-	1	-	-	-	-	-	-	-	-	-	-	5.71
2011	2	2/1/11	10	-	66.71	-	37.15	7.54	-	-	1	-	-	-	-	-	-	-	-	-	-	5.71
2011	3	3/2/11	9	-	56.02	-	27.04	7.54	-	-	-	1	-	-	-	-	-	-	-	-	-	5.64
2011	3	3/7/11	19	-	53.17	-	27.04	7.54	-	-	-	1	-	-	-	-	-	-	-	-	-	5.64

2011	3	3/7/11	20	-	53.17	-	27.04	7.54	-	-	-	1	-	-	-	-	-	-	-	-	-	5.64
2011	4	4/14/11	11	-	25.91	-	15.94	7.54	-	-	-	-	1	-	-	-	-	-	-	-	-	5.47
2011	4	4/14/11	12	-	25.91	-	15.94	7.54	-	-	-	-	1	-	-	-	-	-	-	-	-	5.47
2011	4	4/14/11	13	-	25.91	-	15.94	7.54	-	-	-	-	1	-	-	-	-	-	-	-	-	5.47
2011	5	5/12/11	13	-	14.92	0.01	9.03	7.54	-	-	-	-	-	1	-	-	-	-	-	-	-	5.46
2011	6	6/29/11	15	21.22	-	4.46	1.07	7.54	-	-	-	-	-	-	1	-	-	-	-	-	-	5.74
2011	6	6/29/11	16	21.22	-	4.46	1.07	7.54	-	-	-	-	-	-	1	-	-	-	-	-	-	5.74
2011	6	6/29/11	18	21.22	-	4.46	1.07	7.54	-	-	-	-	-	-	1	-	-	-	-	-	-	5.74
2011	7	7/19/11	16	25.72	-	14.85	-	7.54	-	-	-	-	-	-	-	1	-	-	-	-	-	5.87
2011	8	8/1/11	14	22.16	-	13.09	-	7.54	-	-	-	-	-	-	-	-	1	-	-	-	-	5.83
2011	8	8/1/11	15	22.16	-	13.09	-	7.54	-	-	-	-	-	-	-	-	1	-	-	-	-	5.83
2011	9	9/1/11	17	10.22	-	4.50	2.28	7.54	-	-	-	-	-	-	-	-	-	1	-	-	-	5.62
2011	10	10/4/11	16	12.27	-	1.92	10.06	7.54	-	-	-	-	-	-	-	-	-	-	1	-	-	5.55
2011	11	11/19/11	18	-	47.85	-	23.35	7.54	1.00	-	-	-	-	-	-	-	-	-	-	1	-	5.60
2011	12	12/5/11	18	-	46.17	-	29.08	7.54	-	-	-	-	-	-	-	-	-	-	-	-	1	5.64
2011	12	12/5/11	19	-	46.17	-	29.08	7.54	-	-	-	-	-	-	-	-	-	-	-	-	1	5.64
2011	12	12/5/11	21	-	46.17	-	29.08	7.54	-	-	-	-	-	-	-	-	-	-	-	-	1	5.64
2011	12	12/6/11	8	-	39.27	-	29.08	7.54	-	-	-	-	-	-	-	-	-	-	-	-	1	5.62
2012	1	1/11/12	18	-	36.04	-	28.52	7.58	-	1	-	-	-	-	-	-	-	-	-	-	-	5.65
2012	2	2/10/12	10	-	47.78	-	32.03	7.58	-	-	1	-	-	-	-	-	-	-	-	-	-	5.65
2012	2	2/10/12	12	-	47.78	-	32.03	7.58	-	-	1	-	-	-	-	-	-	-	-	-	-	5.65
2012	2	2/10/12	20	-	47.78	-	32.03	7.58	-	-	1	-	-	-	-	-	-	-	-	-	-	5.65
2012	2	2/10/12	22	-	47.78	-	32.03	7.58	-	-	1	-	-	-	-	-	-	-	-	-	-	5.65
2012	2	2/27/12	8	-	39.46	-	32.03	7.58	-	-	1	-	-	-	-	-	-	-	-	-	-	5.62
2012	2	2/27/12	9	-	39.46	-	32.03	7.58	-	-	1	-	-	-	-	-	-	-	-	-	-	5.62
2012	3	3/1/12	20	-	28.27	0.30	11.32	7.58	-	-	-	1	-	-	-	-	-	-	-	-	-	5.52
2012	3	3/2/12	10	-	34.51	0.30	11.32	7.58	-	-	-	1	-	-	-	-	-	-	-	-	-	5.53
2012	3	3/2/12	18	-	34.51	0.30	11.32	7.58	-	-	-	1	-	-	-	-	-	-	-	-	-	5.53
2012	3	3/2/12	21	-	34.51	0.30	11.32	7.58	-	-	-	1	-	-	-	-	-	-	-	-	-	5.53
2012	4	4/24/12	15	12.35	-	1.02	9.29	7.58	-	-	-	-	1	-	-	-	-	-	-	-	-	5.51
2012	4	4/24/12	16	12.35	-	1.02	9.29	7.58	-	-	-	-	1	-	-	-	-	-	-	-	-	5.51
2012	5	5/17/12	14	12.28	-	1.70	4.61	7.58	-	-	-	-	-	1	-	-	-	-	-	-	-	5.54
2012	6	6/26/12	14	24.90	-	11.01	-	7.58	-	-	-	-	-	-	1	-	-	-	-	-	-	5.85
2012	6	6/26/12	15	24.90	-	11.01	-	7.58	-	-	-	-	-	-	1	-	-	-	-	-	-	5.85
2012	7	7/16/12	15	25.07	-	18.48	-	7.58	-	-	-	-	-	-	-	1	-	-	-	-	-	5.92
2012	7	7/19/12	17	24.21	-	18.48	-	7.58	-	-	-	-	-	-	-	1	-	-	-	-	-	5.91
2012	8	8/28/12	16	23.74	-	13.00	0.01	7.58	-	-	-	-	-	-	-	-	1	-	-	-	-	5.86
2012	9	9/1/12	16	24.37	-	5.70	0.49	7.58	1.00	-	-	-	-	-	-	-	-	1	-	-	-	5.74
2012	9	9/1/12	17	24.37	-	5.70	0.49	7.58	1.00	-	-	-	-	-	-	-	-	1	-	-	-	5.74
2012	9	9/10/12	14	17.59	-	5.70	0.49	7.58	-	-	-	-	-	-	-	-	-	1	-	-	-	5.71

2012	10	10/24/12	19	-	22.45	0.12	13.11	7.58	-	-	-	-	-	-	-	-	-	-	1	-	-	5.51
2012	11	11/11/12	18	-	44.05	-	20.79	7.58	1.00	-	-	-	-	-	-	-	-	-	-	1	-	5.59
2012	12	12/27/12	19	-	52.40	-	32.31	7.58	-	-	-	-	-	-	-	-	-	-	-	-	1	5.68
2013	1	1/31/13	11	-	50.46	-	32.60	7.57	-	1	-	-	-	-	-	-	-	-	-	-	-	5.71
2013	1	1/31/13	19	-	50.46	-	32.60	7.57	-	1	-	-	-	-	-	-	-	-	-	-	-	5.71
2013	2	2/19/13	10	-	40.69	-	28.55	7.57	-	-	1	-	-	-	-	-	-	-	-	-	-	5.61
2013	3	3/13/13	13	-	15.51	-	25.43	7.57	-	-	-	1	-	-	-	-	-	-	-	-	-	5.54
2013	4	4/9/13	11	-	43.55	-	22.06	7.57	-	-	-	-	1	-	-	-	-	-	-	-	-	5.56
2013	4	4/9/13	12	-	43.55	-	22.06	7.57	-	-	-	-	1	-	-	-	-	-	-	-	-	5.56
2013	4	4/9/13	13	-	43.55	-	22.06	7.57	-	-	-	-	1	-	-	-	-	-	-	-	-	5.56
2013	5	5/7/13	15	-	1.25	1.78	5.38	7.57	-	-	-	-	-	1	-	-	-	-	-	-	-	5.44
2013	6	6/27/13	16	15.01	-	6.29	0.95	7.57	-	-	-	-	-	-	1	-	-	-	-	-	-	5.72
2013	6	6/27/13	17	15.01	-	6.29	0.95	7.57	-	-	-	-	-	-	1	-	-	-	-	-	-	5.72
2013	7	7/11/13	16	21.64	-	12.87	-	7.57	-	-	-	-	-	-	-	1	-	-	-	-	-	5.83
2013	7	7/17/13	17	16.13	-	12.87	-	7.57	-	-	-	-	-	-	-	1	-	-	-	-	-	5.78
2013	7	7/17/13	18	16.13	-	12.87	-	7.57	-	-	-	-	-	-	-	1	-	-	-	-	-	5.78
2013	7	7/18/13	13	19.32	-	12.87	-	7.57	-	-	-	-	-	-	-	1	-	-	-	-	-	5.81
2013	7	7/18/13	14	19.32	-	12.87	-	7.57	-	-	-	-	-	-	-	1	-	-	-	-	-	5.81
2013	8	8/27/13	16	22.37	-	13.14	-	7.57	-	-	-	-	-	-	-	-	1	-	-	-	-	5.85
2013	9	9/5/13	14	18.55	-	7.45	1.05	7.57	-	-	-	-	-	-	-	-	-	1	-	-	-	5.73
2013	10	10/28/13	18	-	25.89	-	16.05	7.57	-	-	-	-	-	-	-	-	-	-	1	-	-	5.53
2013	10	10/28/13	19	-	25.89	-	16.05	7.57	-	-	-	-	-	-	-	-	-	-	1	-	-	5.53
2013	11	11/11/13	18	-	33.74	-	23.97	7.57	-	-	-	-	-	-	-	-	-	-	-	1	-	5.60
2013	12	12/7/13	17	-	70.96	-	38.69	7.57	1.00	-	-	-	-	-	-	-	-	-	-	-	1	5.74
2014	1	1/5/14	19	-	59.57	-	32.11	7.64	1.00	1	-	-	-	-	-	-	-	-	-	-	-	5.73
2014	2	2/4/14	19	-	56.89	-	40.69	7.64	-	-	1	-	-	-	-	-	-	-	-	-	-	5.73
2014	2	2/5/14	8	-	66.01	-	40.69	7.64	-	-	1	-	-	-	-	-	-	-	-	-	-	5.75
2014	2	2/5/14	18	-	66.01	-	40.69	7.64	-	-	1	-	-	-	-	-	-	-	-	-	-	5.75
2014	2	2/5/14	20	-	66.01	-	40.69	7.64	-	-	1	-	-	-	-	-	-	-	-	-	-	5.75
2014	2	2/6/14	19	-	67.59	-	40.69	7.64	-	-	1	-	-	-	-	-	-	-	-	-	-	5.76
2014	3	3/1/14	19	-	63.39	-	28.05	7.64	1.00	-	-	1	-	-	-	-	-	-	-	-	-	5.68
2014	4	4/1/14	8	-	41.20	-	15.84	7.64	-	-	-	-	1	-	-	-	-	-	-	-	-	5.55
2014	4	4/1/14	10	-	41.20	-	15.84	7.64	-	-	-	-	1	-	-	-	-	-	-	-	-	5.55
2014	5	5/29/14	16	15.02	-	1.88	7.30	7.64	-	-	-	-	-	1	-	-	-	-	-	-	-	5.60
2014	6	6/26/14	15	9.08	-	3.51	1.18	7.64	-	-	-	-	-	-	1	-	-	-	-	-	-	5.66
2014	7	7/21/14	16	20.53	-	10.82	-	7.64	-	-	-	-	-	-	-	1	-	-	-	-	-	5.82
2014	7	7/21/14	17	20.53	-	10.82	-	7.64	-	-	-	-	-	-	-	1	-	-	-	-	-	5.82
2014	8	8/13/14	15	14.75	-	9.70	0.04	7.64	-	-	-	-	-	-	-	-	1	-	-	-	-	5.77
2014	9	9/26/14	16	16.16	-	4.82	3.73	7.64	-	-	-	-	-	-	-	-	-	1	-	-	-	5.72
2014	9	9/26/14	17	16.16	-	4.82	3.73	7.64	-	-	-	-	-	-	-	-	-	1	-	-	-	5.72

2014	10	10/2/14	19	-	11.81	0.20	7.41	7.64	-	-	-	-	-	-	-	-	-	-	1	-	-	5.48
2014	10	10/3/14	8	-	18.03	0.20	7.41	7.64	-	-	-	-	-	-	-	-	-	-	1	-	-	5.50
2014	10	10/3/14	9	-	18.03	0.20	7.41	7.64	-	-	-	-	-	-	-	-	-	-	1	-	-	5.50
2014	11	11/11/14	19	-	53.33	-	29.66	7.64	-	-	-	-	-	-	-	-	-	-	-	1	-	5.70
2014	12	12/30/14	18	-	61.71	-	29.72	7.64	-	-	-	-	-	-	-	-	-	-	-	-	1	5.72
2014	12	12/30/14	19	-	61.71	-	29.72	7.64	-	-	-	-	-	-	-	-	-	-	-	-	1	5.72
2014	12	12/30/14	20	-	61.71	-	29.72	7.64	-	-	-	-	-	-	-	-	-	-	-	-	1	5.72
2015	1	1/8/15	18	-	30.78	-	28.63	7.66	-	1	-	-	-	-	-	-	-	-	-	-	-	5.67
2015	2	2/27/15	8	-	52.41	-	30.42	7.66	-	-	1	-	-	-	-	-	-	-	-	-	-	5.68
2015	3	3/3/15	22	-	38.27	0.25	16.25	7.66	-	-	-	1	-	-	-	-	-	-	-	-	-	5.59
2015	4	4/9/15	9	-	19.56	-	12.68	7.66	-	-	-	-	1	-	-	-	-	-	-	-	-	5.49
2015	5	5/19/15	21	-	18.38	0.18	8.70	7.66	-	-	-	-	-	1	-	-	-	-	-	-	-	5.52
2015	6	6/29/15	17	14.77	-	7.05	0.13	7.66	-	-	-	-	-	-	1	-	-	-	-	-	-	5.75
2015	7	7/23/15	16	17.56	-	11.49	-	7.66	-	-	-	-	-	-	-	1	-	-	-	-	-	5.81
2015	7	7/23/15	17	17.56	-	11.49	-	7.66	-	-	-	-	-	-	-	1	-	-	-	-	-	5.81
2015	8	8/5/15	17	13.70	-	11.34	0.26	7.66	-	-	-	-	-	-	-	-	1	-	-	-	-	5.78
2015	8	8/12/15	16	20.12	-	11.34	0.26	7.66	-	-	-	-	-	-	-	-	1	-	-	-	-	5.84
2015	9	9/2/15	16	18.38	-	6.87	0.37	7.66	-	-	-	-	-	-	-	-	-	1	-	-	-	5.75
2015	9	9/3/15	15	20.14	-	6.87	0.37	7.66	-	-	-	-	-	-	-	-	-	1	-	-	-	5.77
2015	9	9/3/15	17	20.14	-	6.87	0.37	7.66	-	-	-	-	-	-	-	-	-	1	-	-	-	5.77
2015	10	10/28/15	20	-	22.44	0.82	7.93	7.66	-	-	-	-	-	-	-	-	-	-	1	-	-	5.53
2015	10	10/29/15	8	-	25.59	0.82	7.93	7.66	-	-	-	-	-	-	-	-	-	-	1	-	-	5.54
2015	11	11/30/15	20	-	43.30	-	22.65	7.66	-	-	-	-	-	-	-	-	-	-	-	1	-	5.65
2015	12	12/29/15	18	-	53.19	-	31.47	7.66	-	-	-	-	-	-	-	-	-	-	-	-	1	5.71
2015	12	12/30/15	9	-	49.00	-	31.47	7.66	-	-	-	-	-	-	-	-	-	-	-	-	1	5.70
2016	1	1/8/16	10	-	43.35	-	31.42	7.66	-	1	-	-	-	-	-	-	-	-	-	-	-	5.71
2016	2	2/2/16	19	-	35.29	-	22.18	7.66	-	-	1	-	-	-	-	-	-	-	-	-	-	5.60
2016	2	2/3/16	19	-	35.56	-	22.18	7.66	-	-	1	-	-	-	-	-	-	-	-	-	-	5.60
2016	2	2/4/16	8	-	34.51	-	22.18	7.66	-	-	1	-	-	-	-	-	-	-	-	-	-	5.60
2016	3	3/23/16	12	-	29.79	-	17.84	7.66	-	-	-	1	-	-	-	-	-	-	-	-	-	5.58
2016	4	4/26/16	13	-	22.31	0.28	12.73	7.66	-	-	-	-	1	-	-	-	-	-	-	-	-	5.50
2016	5	5/5/16	17	3.80	-	0.90	4.98	7.66	-	-	-	-	-	1	-	-	-	-	-	-	-	5.49
2016	5	5/13/16	10	-	13.99	0.90	4.98	7.66	-	-	-	-	-	1	-	-	-	-	-	-	-	5.50
2016	5	5/19/16	15	0.93	-	0.90	4.98	7.66	-	-	-	-	-	1	-	-	-	-	-	-	-	5.46
2016	6	6/16/16	15	18.63	-	12.14	0.02	7.66	-	-	-	-	-	-	1	-	-	-	-	-	-	5.84
2016	6	6/24/16	16	19.71	-	12.14	0.02	7.66	-	-	-	-	-	-	1	-	-	-	-	-	-	5.85
2016	7	7/20/16	15	22.79	-	13.87	-	7.66	-	-	-	-	-	-	-	1	-	-	-	-	-	5.88
2016	7	7/20/16	16	22.79	-	13.87	-	7.66	-	-	-	-	-	-	-	1	-	-	-	-	-	5.88
2016	7	7/20/16	17	22.79	-	13.87	-	7.66	-	-	-	-	-	-	-	1	-	-	-	-	-	5.88
2016	8	8/10/16	16	17.46	-	10.80	0.12	7.66	-	-	-	-	-	-	-	-	1	-	-	-	-	5.81

2016	9	9/1/16	16	10.01	-	3.52	1.02	7.66	-	-	-	-	-	-	-	-	-	1	-	-	-	5.65
2016	9	9/1/16	17	10.01	-	3.52	1.02	7.66	-	-	-	-	-	-	-	-	-	1	-	-	-	5.65
2016	10	10/1/16	18	4.54	-	0.62	7.14	7.66	1.00	-	-	-	-	-	-	-	-	-	1	-	-	5.48
2016	10	10/12/16	10	-	21.75	0.62	7.14	7.66	-	-	-	-	-	-	-	-	-	-	1	-	-	5.52
2016	11	11/29/16	9	-	33.42	-	15.60	7.66	-	-	-	-	-	-	-	-	-	-	-	1	-	5.60
2016	12	12/8/16	18	-	55.22	-	39.98	7.66	-	-	-	-	-	-	-	-	-	-	-	-	1	5.75
2016	12	12/9/16	9	-	59.82	-	39.98	7.66	-	-	-	-	-	-	-	-	-	-	-	-	1	5.77
2016	12	12/9/16	17	-	59.82	-	39.98	7.66	-	-	-	-	-	-	-	-	-	-	-	-	1	5.77
2016	12	12/17/16	18	-	63.90	-	39.98	7.66	1.00	-	-	-	-	-	-	-	-	-	-	-	1	5.75
2017	1	1/6/17	9	-	52.11	-	37.89	7.67	-	1	-	-	-	-	-	-	-	-	-	-	-	5.77
2017	2	2/3/17	8	-	49.47	-	26.66	7.67	-	-	1	-	-	-	-	-	-	-	-	-	-	5.66
2017	3	3/10/17	11	-	40.80	-	19.54	7.67	-	-	-	1	-	-	-	-	-	-	-	-	-	5.62
2017	4	4/26/17	8	-	28.82	0.01	13.71	7.67	-	-	-	-	1	-	-	-	-	-	-	-	-	5.52
2017	5	5/12/17	15	2.61	-	1.25	5.37	7.67	-	-	-	-	-	1	-	-	-	-	-	-	-	5.49
2017	5	5/17/17	11	-	10.59	1.25	5.37	7.67	-	-	-	-	-	1	-	-	-	-	-	-	-	5.49
2017	5	5/17/17	17	-	10.59	1.25	5.37	7.67	-	-	-	-	-	1	-	-	-	-	-	-	-	5.49
2017	5	5/18/17	12	-	17.92	1.25	5.37	7.67	-	-	-	-	-	1	-	-	-	-	-	-	-	5.51
2017	6	6/9/17	17	17.79	-	8.09	0.01	7.67	-	-	-	-	-	-	1	-	-	-	-	-	-	5.79
2017	7	7/20/17	15	20.28	-	17.38	-	7.67	-	-	-	-	-	-	-	1	-	-	-	-	-	5.90
2017	7	7/20/17	18	20.28	-	17.38	-	7.67	-	-	-	-	-	-	-	1	-	-	-	-	-	5.90
2017	8	8/28/17	16	13.52	-	9.15	-	7.67	-	-	-	-	-	-	-	-	1	-	-	-	-	5.76
2017	8	8/28/17	17	13.52	-	9.15	-	7.67	-	-	-	-	-	-	-	-	1	-	-	-	-	5.76
2017	8	8/29/17	15	15.98	-	9.15	-	7.67	-	-	-	-	-	-	-	-	1	-	-	-	-	5.78
2017	8	8/29/17	16	15.98	-	9.15	-	7.67	-	-	-	-	-	-	-	-	1	-	-	-	-	5.78
2017	9	9/11/17	17	15.86	-	5.41	3.60	7.67	-	-	-	-	-	-	-	-	-	1	-	-	-	5.73
2017	10	10/31/17	9	-	29.00	0.40	10.44	7.67	-	-	-	-	-	-	-	-	-	-	1	-	-	5.56
2017	11	11/6/17	18	-	36.54	0.06	20.69	7.67	-	-	-	-	-	-	-	-	-	-	-	1	-	5.63
2017	12	12/30/17	18	-	64.18	-	33.52	7.67	1.00	-	-	-	-	-	-	-	-	-	-	-	1	5.73
2017	12	12/30/17	19	-	64.18	-	33.52	7.67	1.00	-	-	-	-	-	-	-	-	-	-	-	1	5.73
2018	1	1/15/18	20	-	54.74	-	33.20	7.70	-	1	-	-	-	-	-	-	-	-	-	-	-	5.76
2018	1	1/16/18	8	-	54.35	-	33.20	7.70	-	1	-	-	-	-	-	-	-	-	-	-	-	5.76
2018	1	1/16/18	9	-	54.35	-	33.20	7.70	-	1	-	-	-	-	-	-	-	-	-	-	-	5.76
2018	2	2/21/18	7	-	58.32	-	43.86	7.70	-	-	1	-	-	-	-	-	-	-	-	-	-	5.77
2018	3	3/5/18	18	-	33.69	-	26.67	7.70	-	-	-	1	-	-	-	-	-	-	-	-	-	5.63
2018	3	3/5/18	19	-	33.69	-	26.67	7.70	-	-	-	1	-	-	-	-	-	-	-	-	-	5.63
2018	3	3/5/18	20	-	33.69	-	26.67	7.70	-	-	-	1	-	-	-	-	-	-	-	-	-	5.63
2018	3	3/6/18	9	-	35.65	-	26.67	7.70	-	-	-	1	-	-	-	-	-	-	-	-	-	5.64
2018	4	4/6/18	9	-	42.68	0.08	20.30	7.70	-	-	-	-	1	-	-	-	-	-	-	-	-	5.59
2018	4	4/6/18	10	-	42.68	0.08	20.30	7.70	-	-	-	-	1	-	-	-	-	-	-	-	-	5.59
2018	5	5/31/18	17	10.71	-	3.74	3.58	7.70	-	-	-	-	-	1	-	-	-	-	-	-	-	5.58

2018	6	6/14/18	17	18.96	-	7.63	0.41	7.70	-	-	-	-	-	-	1	-	-	-	-	-	-	5.81
2018	7	7/10/18	17	20.79	-	11.08	-	7.70	-	-	-	-	-	-	-	1	-	-	-	-	-	5.84
2018	8	8/2/18	16	11.55	-	9.34	0.20	7.70	-	-	-	-	-	-	-	-	1	-	-	-	-	5.76
2018	8	8/3/18	15	17.40	-	9.34	0.20	7.70	-	-	-	-	-	-	-	-	1	-	-	-	-	5.81
2018	8	8/3/18	16	17.40	-	9.34	0.20	7.70	-	-	-	-	-	-	-	-	1	-	-	-	-	5.81
2018	8	8/10/18	16	18.36	-	9.34	0.20	7.70	-	-	-	-	-	-	-	-	1	-	-	-	-	5.82
2018	8	8/10/18	17	18.36	-	9.34	0.20	7.70	-	-	-	-	-	-	-	-	1	-	-	-	-	5.82
2018	9	9/12/18	17	10.08	-	4.71	3.55	7.70	-	-	-	-	-	-	-	-	-	1	-	-	-	5.68
2018	10	10/8/18	19	-	25.09	0.03	14.31	7.70	-	-	-	-	-	-	-	-	-	-	1	-	-	5.57
2018	11	11/9/18	8	-	45.61	-	25.69	7.70	-	-	-	-	-	-	-	-	-	-	-	1	-	5.68
2018	11	11/17/18	19	-	39.47	-	25.69	7.70	1.00	-	-	-	-	-	-	-	-	-	-	1	-	5.64
2018	12	12/27/18	12	-	44.05	-	30.22	7.70	-	-	-	-	-	-	-	-	-	-	-	-	1	5.69
2018	12	12/27/18	17	-	44.05	-	30.22	7.70	-	-	-	-	-	-	-	-	-	-	-	-	1	5.69
2019	1	1/18/19	11	-	44.99	-	32.08	7.72	-	1	-	-	-	-	-	-	-	-	-	-	-	5.74
2019	1	1/29/19	19	-	48.44	-	32.08	7.72	-	1	-	-	-	-	-	-	-	-	-	-	-	5.75
2019	1	1/30/19	9	-	50.48	-	32.08	7.72	-	1	-	-	-	-	-	-	-	-	-	-	-	5.75
2019	2	2/25/19	20	-	59.96	-	50.54	7.72	-	-	1	-	-	-	-	-	-	-	-	-	-	5.81
2019	3	3/3/19	20	-	65.12	-	30.78	7.72	1.00	-	-	1	-	-	-	-	-	-	-	-	-	5.72
2019	3	3/4/19	8	-	60.40	-	30.78	7.72	-	-	-	1	-	-	-	-	-	-	-	-	-	5.73
2019	3	3/4/19	9	-	60.40	-	30.78	7.72	-	-	-	1	-	-	-	-	-	-	-	-	-	5.73
2019	4	4/30/19	7	-	29.84	0.07	15.35	7.72	-	-	-	-	1	-	-	-	-	-	-	-	-	5.55
2019	4	4/30/19	8	-	29.84	0.07	15.35	7.72	-	-	-	-	1	-	-	-	-	-	-	-	-	5.55
2019	5	5/21/19	9	-	25.15	0.51	12.64	7.72	-	-	-	-	-	1	-	-	-	-	-	-	-	5.57
2019	5	5/21/19	17	-	25.15	0.51	12.64	7.72	-	-	-	-	-	1	-	-	-	-	-	-	-	5.57
2019	6	6/28/19	16	14.22	-	4.63	0.53	7.72	-	-	-	-	-	-	1	-	-	-	-	-	-	5.74
2019	6	6/28/19	17	14.22	-	4.63	0.53	7.72	-	-	-	-	-	-	1	-	-	-	-	-	-	5.74
2019	7	7/24/19	15	14.69	-	10.02	-	7.72	-	-	-	-	-	-	-	1	-	-	-	-	-	5.79
2019	7	7/31/19	15	11.93	-	10.02	-	7.72	-	-	-	-	-	-	-	1	-	-	-	-	-	5.76
2019	8	8/6/19	15	13.62	-	8.15	-	7.72	-	-	-	-	-	-	-	-	1	-	-	-	-	5.77
2019	9	9/2/19	16	15.37	-	4.73	1.93	7.72	-	-	-	-	-	-	-	-	-	1	-	-	-	5.73
2019	9	9/4/19	16	10.57	-	4.73	1.93	7.72	-	-	-	-	-	-	-	-	-	1	-	-	-	5.69
2019	10	10/30/19	7	-	44.31	-	20.01	7.72	-	-	-	-	-	-	-	-	-	-	1	-	-	5.65
2019	11	11/6/19	18	-	36.39	-	25.88	7.72	-	-	-	-	-	-	-	-	-	-	-	1	-	5.67
2019	12	12/9/19	8	-	39.40	-	28.17	7.72	-	-	-	-	-	-	-	-	-	-	-	-	1	5.68
2019	12	12/16/19	18	-	33.39	-	28.17	7.72	-	-	-	-	-	-	-	-	-	-	-	-	1	5.66
2020	1			-	49.39	-	32.54	7.74	-	1	-	-	-	-	-	-	-	-	-	-	-	5.76
2020	2			-	52.46	-	33.49	7.74	-	-	1	-	-	-	-	-	-	-	-	-	-	5.72
2020	3			-	40.59	0.04	23.14	7.74	-	-	-	1	-	-	-	-	-	-	-	-	-	5.65
2020	4			-	29.51	0.13	15.08	7.74	-	-	-	-	1	-	-	-	-	-	-	-	-	5.55
2020	5			10.30	-	1.75	5.99	7.74	-	-	-	-	-	1	-	-	-	-	-	-	-	5.59

2020	6			16.76	-	6.64	0.86	7.74	-	-	-	-	-	-	1	-	-	-	-	-	-	5.80
2020	7			21.27	-	14.01	0.01	7.74	-	-	-	-	-	-	-	1	-	-	-	-	-	5.89
2020	8			18.79	-	11.18	0.07	7.74	-	-	-	-	-	-	-	-	1	-	-	-	-	5.85
2020	9			15.24	-	4.84	2.24	7.74	-	-	-	-	-	-	-	-	-	1	-	-	-	5.74
2020	10			-	24.95	0.37	12.63	7.74	-	-	-	-	-	-	-	-	-	-	1	-	-	5.58
2020	11			-	39.87	0.02	22.57	7.74	-	-	-	-	-	-	-	-	-	-	-	1	-	5.67
2020	12			-	52.21	-	32.51	7.74	-	-	-	-	-	-	-	-	-	-	-	-	1	5.74
2021	1			-	49.39	-	32.54	7.76	-	1	-	-	-	-	-	-	-	-	-	-	-	5.77
2021	2			-	52.46	-	33.49	7.76	-	-	1	-	-	-	-	-	-	-	-	-	-	5.73
2021	3			-	40.59	0.04	23.14	7.76	-	-	-	1	-	-	-	-	-	-	-	-	-	5.66
2021	4			-	29.51	0.13	15.08	7.76	-	-	-	-	1	-	-	-	-	-	-	-	-	5.56
2021	5			10.30	-	1.75	5.99	7.76	-	-	-	-	-	1	-	-	-	-	-	-	-	5.59
2021	6			16.76	-	6.64	0.86	7.76	-	-	-	-	-	-	1	-	-	-	-	-	-	5.80
2021	7			21.27	-	14.01	0.01	7.76	-	-	-	-	-	-	-	1	-	-	-	-	-	5.90
2021	8			18.79	-	11.18	0.07	7.76	-	-	-	-	-	-	-	-	1	-	-	-	-	5.86
2021	9			15.24	-	4.84	2.24	7.76	-	-	-	-	-	-	-	-	-	1	-	-	-	5.75
2021	10			-	24.95	0.37	12.63	7.76	-	-	-	-	-	-	-	-	-	-	1	-	-	5.58
2021	11			-	39.87	0.02	22.57	7.76	-	-	-	-	-	-	-	-	-	-	-	1	-	5.68
2021	12			-	52.21	-	32.51	7.76	-	-	-	-	-	-	-	-	-	-	-	-	1	5.75
2022	1			-	49.39	-	32.54	7.79	-	1	-	-	-	-	-	-	-	-	-	-	-	5.77
2022	2			-	52.46	-	33.49	7.79	-	-	1	-	-	-	-	-	-	-	-	-	-	5.73
2022	3			-	40.59	0.04	23.14	7.79	-	-	-	1	-	-	-	-	-	-	-	-	-	5.67
2022	4			-	29.51	0.13	15.08	7.79	-	-	-	-	1	-	-	-	-	-	-	-	-	5.57
2022	5			10.30	-	1.75	5.99	7.79	-	-	-	-	-	1	-	-	-	-	-	-	-	5.60
2022	6			16.76	-	6.64	0.86	7.79	-	-	-	-	-	-	1	-	-	-	-	-	-	5.81
2022	7			21.27	-	14.01	0.01	7.79	-	-	-	-	-	-	-	1	-	-	-	-	-	5.91
2022	8			18.79	-	11.18	0.07	7.79	-	-	-	-	-	-	-	-	1	-	-	-	-	5.87
2022	9			15.24	-	4.84	2.24	7.79	-	-	-	-	-	-	-	-	-	1	-	-	-	5.75
2022	10			-	24.95	0.37	12.63	7.79	-	-	-	-	-	-	-	-	-	-	1	-	-	5.59
2022	11			-	39.87	0.02	22.57	7.79	-	-	-	-	-	-	-	-	-	-	-	1	-	5.68
2022	12			-	52.21	-	32.51	7.79	-	-	-	-	-	-	-	-	-	-	-	-	1	5.75
2023	1			-	49.39	-	32.54	7.81	-	1	-	-	-	-	-	-	-	-	-	-	-	5.78
2023	2			-	52.46	-	33.49	7.81	-	-	1	-	-	-	-	-	-	-	-	-	-	5.74
2023	3			-	40.59	0.04	23.14	7.81	-	-	-	1	-	-	-	-	-	-	-	-	-	5.68
2023	4			-	29.51	0.13	15.08	7.81	-	-	-	-	1	-	-	-	-	-	-	-	-	5.57
2023	5			10.30	-	1.75	5.99	7.81	-	-	-	-	-	1	-	-	-	-	-	-	-	5.61
2023	6			16.76	-	6.64	0.86	7.81	-	-	-	-	-	-	1	-	-	-	-	-	-	5.82
2023	7			21.27	-	14.01	0.01	7.81	-	-	-	-	-	-	-	1	-	-	-	-	-	5.92
2023	8			18.79	-	11.18	0.07	7.81	-	-	-	-	-	-	-	-	1	-	-	-	-	5.87
2023	9			15.24	-	4.84	2.24	7.81	-	-	-	-	-	-	-	-	-	1	-	-	-	5.76

2023	10			-	24.95	0.37	12.63	7.81	-	-	-	-	-	-	-	-	-	-	1	-	-	5.60
2023	11			-	39.87	0.02	22.57	7.81	-	-	-	-	-	-	-	-	-	-	-	1	-	5.69
2023	12			-	52.21	-	32.51	7.81	-	-	-	-	-	-	-	-	-	-	-	-	1	5.76
2024	1			-	49.39	-	32.54	7.83	-	1	-	-	-	-	-	-	-	-	-	-	-	5.79
2024	2			-	52.46	-	33.49	7.83	-	-	1	-	-	-	-	-	-	-	-	-	-	5.75
2024	3			-	40.59	0.04	23.14	7.83	-	-	-	1	-	-	-	-	-	-	-	-	-	5.68
2024	4			-	29.51	0.13	15.08	7.83	-	-	-	-	1	-	-	-	-	-	-	-	-	5.58
2024	5			10.30	-	1.75	5.99	7.83	-	-	-	-	-	1	-	-	-	-	-	-	-	5.61
2024	6			16.76	-	6.64	0.86	7.83	-	-	-	-	-	-	1	-	-	-	-	-	-	5.82
2024	7			21.27	-	14.01	0.01	7.83	-	-	-	-	-	-	-	1	-	-	-	-	-	5.92
2024	8			18.79	-	11.18	0.07	7.83	-	-	-	-	-	-	-	-	1	-	-	-	-	5.88
2024	9			15.24	-	4.84	2.24	7.83	-	-	-	-	-	-	-	-	-	1	-	-	-	5.77
2024	10			-	24.95	0.37	12.63	7.83	-	-	-	-	-	-	-	-	-	-	1	-	-	5.61
2024	11			-	39.87	0.02	22.57	7.83	-	-	-	-	-	-	-	-	-	-	-	1	-	5.70
2024	12			-	52.21	-	32.51	7.83	-	-	-	-	-	-	-	-	-	-	-	-	1	5.77
2025	1			-	49.39	-	32.54	7.85	-	1	-	-	-	-	-	-	-	-	-	-	-	5.80
2025	2			-	52.46	-	33.49	7.85	-	-	1	-	-	-	-	-	-	-	-	-	-	5.76
2025	3			-	40.59	0.04	23.14	7.85	-	-	-	1	-	-	-	-	-	-	-	-	-	5.69
2025	4			-	29.51	0.13	15.08	7.85	-	-	-	-	1	-	-	-	-	-	-	-	-	5.59
2025	5			10.30	-	1.75	5.99	7.85	-	-	-	-	-	1	-	-	-	-	-	-	-	5.62
2025	6			16.76	-	6.64	0.86	7.85	-	-	-	-	-	-	1	-	-	-	-	-	-	5.83
2025	7			21.27	-	14.01	0.01	7.85	-	-	-	-	-	-	-	1	-	-	-	-	-	5.93
2025	8			18.79	-	11.18	0.07	7.85	-	-	-	-	-	-	-	-	1	-	-	-	-	5.89
2025	9			15.24	-	4.84	2.24	7.85	-	-	-	-	-	-	-	-	-	1	-	-	-	5.77
2025	10			-	24.95	0.37	12.63	7.85	-	-	-	-	-	-	-	-	-	-	1	-	-	5.61
2025	11			-	39.87	0.02	22.57	7.85	-	-	-	-	-	-	-	-	-	-	-	1	-	5.71
2025	12			-	52.21	-	32.51	7.85	-	-	-	-	-	-	-	-	-	-	-	-	1	5.78
2026	1			-	49.39	-	32.54	7.87	-	1	-	-	-	-	-	-	-	-	-	-	-	5.80
2026	2			-	52.46	-	33.49	7.87	-	-	1	-	-	-	-	-	-	-	-	-	-	5.76
2026	3			-	40.59	0.04	23.14	7.87	-	-	-	1	-	-	-	-	-	-	-	-	-	5.70
2026	4			-	29.51	0.13	15.08	7.87	-	-	-	-	1	-	-	-	-	-	-	-	-	5.59
2026	5			10.30	-	1.75	5.99	7.87	-	-	-	-	-	1	-	-	-	-	-	-	-	5.63
2026	6			16.76	-	6.64	0.86	7.87	-	-	-	-	-	-	1	-	-	-	-	-	-	5.84
2026	7			21.27	-	14.01	0.01	7.87	-	-	-	-	-	-	-	1	-	-	-	-	-	5.94
2026	8			18.79	-	11.18	0.07	7.87	-	-	-	-	-	-	-	-	1	-	-	-	-	5.89
2026	9			15.24	-	4.84	2.24	7.87	-	-	-	-	-	-	-	-	-	1	-	-	-	5.78
2026	10			-	24.95	0.37	12.63	7.87	-	-	-	-	-	-	-	-	-	-	1	-	-	5.62
2026	11			-	39.87	0.02	22.57	7.87	-	-	-	-	-	-	-	-	-	-	-	1	-	5.71
2026	12			-	52.21	-	32.51	7.87	-	-	-	-	-	-	-	-	-	-	-	-	1	5.78
2027	1			-	49.39	-	32.54	7.89	-	1	-	-	-	-	-	-	-	-	-	-	-	5.81

2027	2			-	52.46	-	33.49	7.89	-	-	1	-	-	-	-	-	-	-	-	-	-	5.77
2027	3			-	40.59	0.04	23.14	7.89	-	-	-	1	-	-	-	-	-	-	-	-	-	5.70
2027	4			-	29.51	0.13	15.08	7.89	-	-	-	-	1	-	-	-	-	-	-	-	-	5.60
2027	5			10.30	-	1.75	5.99	7.89	-	-	-	-	-	1	-	-	-	-	-	-	-	5.63
2027	6			16.76	-	6.64	0.86	7.89	-	-	-	-	-	-	1	-	-	-	-	-	-	5.84
2027	7			21.27	-	14.01	0.01	7.89	-	-	-	-	-	-	-	1	-	-	-	-	-	5.94
2027	8			18.79	-	11.18	0.07	7.89	-	-	-	-	-	-	-	-	1	-	-	-	-	5.90
2027	9			15.24	-	4.84	2.24	7.89	-	-	-	-	-	-	-	-	-	1	-	-	-	5.79
2027	10			-	24.95	0.37	12.63	7.89	-	-	-	-	-	-	-	-	-	-	1	-	-	5.63
2027	11			-	39.87	0.02	22.57	7.89	-	-	-	-	-	-	-	-	-	-	-	1	-	5.72
2027	12			-	52.21	-	32.51	7.89	-	-	-	-	-	-	-	-	-	-	-	-	1	5.79
2028	1			-	49.39	-	32.54	7.90	-	1	-	-	-	-	-	-	-	-	-	-	-	5.81
2028	2			-	52.46	-	33.49	7.90	-	-	1	-	-	-	-	-	-	-	-	-	-	5.78
2028	3			-	40.59	0.04	23.14	7.90	-	-	-	1	-	-	-	-	-	-	-	-	-	5.71
2028	4			-	29.51	0.13	15.08	7.90	-	-	-	-	1	-	-	-	-	-	-	-	-	5.61
2028	5			10.30	-	1.75	5.99	7.90	-	-	-	-	-	1	-	-	-	-	-	-	-	5.64
2028	6			16.76	-	6.64	0.86	7.90	-	-	-	-	-	-	1	-	-	-	-	-	-	5.85
2028	7			21.27	-	14.01	0.01	7.90	-	-	-	-	-	-	-	1	-	-	-	-	-	5.95
2028	8			18.79	-	11.18	0.07	7.90	-	-	-	-	-	-	-	-	1	-	-	-	-	5.91
2028	9			15.24	-	4.84	2.24	7.90	-	-	-	-	-	-	-	-	-	1	-	-	-	5.79
2028	10			-	24.95	0.37	12.63	7.90	-	-	-	-	-	-	-	-	-	-	1	-	-	5.63
2028	11			-	39.87	0.02	22.57	7.90	-	-	-	-	-	-	-	-	-	-	-	1	-	5.72
2028	12			-	52.21	-	32.51	7.90	-	-	-	-	-	-	-	-	-	-	-	-	1	5.79
2029	1			-	49.39	-	32.54	7.92	-	1	-	-	-	-	-	-	-	-	-	-	-	5.82
2029	2			-	52.46	-	33.49	7.92	-	-	1	-	-	-	-	-	-	-	-	-	-	5.78
2029	3			-	40.59	0.04	23.14	7.92	-	-	-	1	-	-	-	-	-	-	-	-	-	5.72
2029	4			-	29.51	0.13	15.08	7.92	-	-	-	-	1	-	-	-	-	-	-	-	-	5.61
2029	5			10.30	-	1.75	5.99	7.92	-	-	-	-	-	1	-	-	-	-	-	-	-	5.65
2029	6			16.76	-	6.64	0.86	7.92	-	-	-	-	-	-	1	-	-	-	-	-	-	5.86
2029	7			21.27	-	14.01	0.01	7.92	-	-	-	-	-	-	-	1	-	-	-	-	-	5.96
2029	8			18.79	-	11.18	0.07	7.92	-	-	-	-	-	-	-	-	1	-	-	-	-	5.91
2029	9			15.24	-	4.84	2.24	7.92	-	-	-	-	-	-	-	-	-	1	-	-	-	5.80
2029	10			-	24.95	0.37	12.63	7.92	-	-	-	-	-	-	-	-	-	-	1	-	-	5.64
2029	11			-	39.87	0.02	22.57	7.92	-	-	-	-	-	-	-	-	-	-	-	1	-	5.73
2029	12			-	52.21	-	32.51	7.92	-	-	-	-	-	-	-	-	-	-	-	-	1	5.80
2030	1			-	49.39	-	32.54	7.94	-	1	-	-	-	-	-	-	-	-	-	-	-	5.83
2030	2			-	52.46	-	33.49	7.94	-	-	1	-	-	-	-	-	-	-	-	-	-	5.79
2030	3			-	40.59	0.04	23.14	7.94	-	-	-	1	-	-	-	-	-	-	-	-	-	5.72
2030	4			-	29.51	0.13	15.08	7.94	-	-	-	-	1	-	-	-	-	-	-	-	-	5.62
2030	5			10.30	-	1.75	5.99	7.94	-	-	-	-	-	1	-	-	-	-	-	-	-	5.65

2030	6			16.76	-	6.64	0.86	7.94	-	-	-	-	-	-	1	-	-	-	-	-	-	5.86
2030	7			21.27	-	14.01	0.01	7.94	-	-	-	-	-	-	-	1	-	-	-	-	-	5.96
2030	8			18.79	-	11.18	0.07	7.94	-	-	-	-	-	-	-	-	1	-	-	-	-	5.92
2030	9			15.24	-	4.84	2.24	7.94	-	-	-	-	-	-	-	-	-	1	-	-	-	5.81
2030	10			-	24.95	0.37	12.63	7.94	-	-	-	-	-	-	-	-	-	-	1	-	-	5.64
2030	11			-	39.87	0.02	22.57	7.94	-	-	-	-	-	-	-	-	-	-	-	1	-	5.74
2030	12			-	52.21	-	32.51	7.94	-	-	-	-	-	-	-	-	-	-	-	-	1	5.81
2031	1			-	49.39	-	32.54	7.96	-	1	-	-	-	-	-	-	-	-	-	-	-	5.83
2031	2			-	52.46	-	33.49	7.96	-	-	1	-	-	-	-	-	-	-	-	-	-	5.79
2031	3			-	40.59	0.04	23.14	7.96	-	-	-	1	-	-	-	-	-	-	-	-	-	5.73
2031	4			-	29.51	0.13	15.08	7.96	-	-	-	-	1	-	-	-	-	-	-	-	-	5.62
2031	5			10.30	-	1.75	5.99	7.96	-	-	-	-	-	1	-	-	-	-	-	-	-	5.66
2031	6			16.76	-	6.64	0.86	7.96	-	-	-	-	-	-	1	-	-	-	-	-	-	5.87
2031	7			21.27	-	14.01	0.01	7.96	-	-	-	-	-	-	-	1	-	-	-	-	-	5.97
2031	8			18.79	-	11.18	0.07	7.96	-	-	-	-	-	-	-	-	1	-	-	-	-	5.93
2031	9			15.24	-	4.84	2.24	7.96	-	-	-	-	-	-	-	-	-	1	-	-	-	5.81
2031	10			-	24.95	0.37	12.63	7.96	-	-	-	-	-	-	-	-	-	-	1	-	-	5.65
2031	11			-	39.87	0.02	22.57	7.96	-	-	-	-	-	-	-	-	-	-	-	1	-	5.74
2031	12			-	52.21	-	32.51	7.96	-	-	-	-	-	-	-	-	-	-	-	-	1	5.81
2032	1			-	49.39	-	32.54	7.97	-	1	-	-	-	-	-	-	-	-	-	-	-	5.84
2032	2			-	52.46	-	33.49	7.97	-	-	1	-	-	-	-	-	-	-	-	-	-	5.80
2032	3			-	40.59	0.04	23.14	7.97	-	-	-	1	-	-	-	-	-	-	-	-	-	5.73
2032	4			-	29.51	0.13	15.08	7.97	-	-	-	-	1	-	-	-	-	-	-	-	-	5.63
2032	5			10.30	-	1.75	5.99	7.97	-	-	-	-	-	1	-	-	-	-	-	-	-	5.66
2032	6			16.76	-	6.64	0.86	7.97	-	-	-	-	-	-	1	-	-	-	-	-	-	5.87
2032	7			21.27	-	14.01	0.01	7.97	-	-	-	-	-	-	-	1	-	-	-	-	-	5.97
2032	8			18.79	-	11.18	0.07	7.97	-	-	-	-	-	-	-	-	1	-	-	-	-	5.93
2032	9			15.24	-	4.84	2.24	7.97	-	-	-	-	-	-	-	-	-	1	-	-	-	5.82
2032	10			-	24.95	0.37	12.63	7.97	-	-	-	-	-	-	-	-	-	-	1	-	-	5.66
2032	11			-	39.87	0.02	22.57	7.97	-	-	-	-	-	-	-	-	-	-	-	1	-	5.75
2032	12			-	52.21	-	32.51	7.97	-	-	-	-	-	-	-	-	-	-	-	-	1	5.82
2033	1			-	49.39	-	32.54	7.99	-	1	-	-	-	-	-	-	-	-	-	-	-	5.84
2033	2			-	52.46	-	33.49	7.99	-	-	1	-	-	-	-	-	-	-	-	-	-	5.80
2033	3			-	40.59	0.04	23.14	7.99	-	-	-	1	-	-	-	-	-	-	-	-	-	5.74
2033	4			-	29.51	0.13	15.08	7.99	-	-	-	-	1	-	-	-	-	-	-	-	-	5.63
2033	5			10.30	-	1.75	5.99	7.99	-	-	-	-	-	1	-	-	-	-	-	-	-	5.67
2033	6			16.76	-	6.64	0.86	7.99	-	-	-	-	-	-	1	-	-	-	-	-	-	5.88
2033	7			21.27	-	14.01	0.01	7.99	-	-	-	-	-	-	-	1	-	-	-	-	-	5.98
2033	8			18.79	-	11.18	0.07	7.99	-	-	-	-	-	-	-	-	1	-	-	-	-	5.94
2033	9			15.24	-	4.84	2.24	7.99	-	-	-	-	-	-	-	-	-	1	-	-	-	5.82

2033	10			-	24.95	0.37	12.63	7.99	-	-	-	-	-	-	-	-	-	-	1	-	-	5.66
2033	11			-	39.87	0.02	22.57	7.99	-	-	-	-	-	-	-	-	-	-	-	1	-	5.75
2033	12			-	52.21	-	32.51	7.99	-	-	-	-	-	-	-	-	-	-	-	-	1	5.82
2034	1			-	49.39	-	32.54	8.00	-	1	-	-	-	-	-	-	-	-	-	-	-	5.85
2034	2			-	52.46	-	33.49	8.00	-	-	1	-	-	-	-	-	-	-	-	-	-	5.81
2034	3			-	40.59	0.04	23.14	8.00	-	-	-	1	-	-	-	-	-	-	-	-	-	5.74
2034	4			-	29.51	0.13	15.08	8.00	-	-	-	-	1	-	-	-	-	-	-	-	-	5.64
2034	5			10.30	-	1.75	5.99	8.00	-	-	-	-	-	1	-	-	-	-	-	-	-	5.67
2034	6			16.76	-	6.64	0.86	8.00	-	-	-	-	-	-	1	-	-	-	-	-	-	5.88
2034	7			21.27	-	14.01	0.01	8.00	-	-	-	-	-	-	-	1	-	-	-	-	-	5.98
2034	8			18.79	-	11.18	0.07	8.00	-	-	-	-	-	-	-	-	1	-	-	-	-	5.94
2034	9			15.24	-	4.84	2.24	8.00	-	-	-	-	-	-	-	-	-	1	-	-	-	5.83
2034	10			-	24.95	0.37	12.63	8.00	-	-	-	-	-	-	-	-	-	-	1	-	-	5.67
2034	11			-	39.87	0.02	22.57	8.00	-	-	-	-	-	-	-	-	-	-	-	1	-	5.76
2034	12			-	52.21	-	32.51	8.00	-	-	-	-	-	-	-	-	-	-	-	-	1	5.83
2035	1			-	49.39	-	32.54	8.02	-	1	-	-	-	-	-	-	-	-	-	-	-	5.85
2035	2			-	52.46	-	33.49	8.02	-	-	1	-	-	-	-	-	-	-	-	-	-	5.81
2035	3			-	40.59	0.04	23.14	8.02	-	-	-	1	-	-	-	-	-	-	-	-	-	5.75
2035	4			-	29.51	0.13	15.08	8.02	-	-	-	-	1	-	-	-	-	-	-	-	-	5.64
2035	5			10.30	-	1.75	5.99	8.02	-	-	-	-	-	1	-	-	-	-	-	-	-	5.68
2035	6			16.76	-	6.64	0.86	8.02	-	-	-	-	-	-	1	-	-	-	-	-	-	5.89
2035	7			21.27	-	14.01	0.01	8.02	-	-	-	-	-	-	-	1	-	-	-	-	-	5.99
2035	8			18.79	-	11.18	0.07	8.02	-	-	-	-	-	-	-	-	1	-	-	-	-	5.95
2035	9			15.24	-	4.84	2.24	8.02	-	-	-	-	-	-	-	-	-	1	-	-	-	5.83
2035	10			-	24.95	0.37	12.63	8.02	-	-	-	-	-	-	-	-	-	-	1	-	-	5.67
2035	11			-	39.87	0.02	22.57	8.02	-	-	-	-	-	-	-	-	-	-	-	1	-	5.76
2035	12			-	52.21	-	32.51	8.02	-	-	-	-	-	-	-	-	-	-	-	-	1	5.83
2036	1			-	49.39	-	32.54	8.03	-	1	-	-	-	-	-	-	-	-	-	-	-	5.86
2036	2			-	52.46	-	33.49	8.03	-	-	1	-	-	-	-	-	-	-	-	-	-	5.82
2036	3			-	40.59	0.04	23.14	8.03	-	-	-	1	-	-	-	-	-	-	-	-	-	5.75
2036	4			-	29.51	0.13	15.08	8.03	-	-	-	-	1	-	-	-	-	-	-	-	-	5.65
2036	5			10.30	-	1.75	5.99	8.03	-	-	-	-	-	1	-	-	-	-	-	-	-	5.68
2036	6			16.76	-	6.64	0.86	8.03	-	-	-	-	-	-	1	-	-	-	-	-	-	5.89
2036	7			21.27	-	14.01	0.01	8.03	-	-	-	-	-	-	-	1	-	-	-	-	-	5.99
2036	8			18.79	-	11.18	0.07	8.03	-	-	-	-	-	-	-	-	1	-	-	-	-	5.95
2036	9			15.24	-	4.84	2.24	8.03	-	-	-	-	-	-	-	-	-	1	-	-	-	5.84
2036	10			-	24.95	0.37	12.63	8.03	-	-	-	-	-	-	-	-	-	-	1	-	-	5.68
2036	11			-	39.87	0.02	22.57	8.03	-	-	-	-	-	-	-	-	-	-	-	1	-	5.77
2036	12			-	52.21	-	32.51	8.03	-	-	-	-	-	-	-	-	-	-	-	-	1	5.84
2037	1			-	49.39	-	32.54	8.05	-	1	-	-	-	-	-	-	-	-	-	-	-	5.86

2037	2			-	52.46	-	33.49	8.05	-	-	1	-	-	-	-	-	-	-	-	-	-	5.82
2037	3			-	40.59	0.04	23.14	8.05	-	-	-	1	-	-	-	-	-	-	-	-	-	5.76
2037	4			-	29.51	0.13	15.08	8.05	-	-	-	-	1	-	-	-	-	-	-	-	-	5.65
2037	5			10.30	-	1.75	5.99	8.05	-	-	-	-	-	1	-	-	-	-	-	-	-	5.69
2037	6			16.76	-	6.64	0.86	8.05	-	-	-	-	-	-	1	-	-	-	-	-	-	5.90
2037	7			21.27	-	14.01	0.01	8.05	-	-	-	-	-	-	-	1	-	-	-	-	-	6.00
2037	8			18.79	-	11.18	0.07	8.05	-	-	-	-	-	-	-	-	1	-	-	-	-	5.96
2037	9			15.24	-	4.84	2.24	8.05	-	-	-	-	-	-	-	-	-	1	-	-	-	5.84
2037	10			-	24.95	0.37	12.63	8.05	-	-	-	-	-	-	-	-	-	-	1	-	-	5.68
2037	11			-	39.87	0.02	22.57	8.05	-	-	-	-	-	-	-	-	-	-	-	1	-	5.77
2037	12			-	52.21	-	32.51	8.05	-	-	-	-	-	-	-	-	-	-	-	-	1	5.84
2038	1			-	49.39	-	32.54	8.06	-	1	-	-	-	-	-	-	-	-	-	-	-	5.87
2038	2			-	52.46	-	33.49	8.06	-	-	1	-	-	-	-	-	-	-	-	-	-	5.83
2038	3			-	40.59	0.04	23.14	8.06	-	-	-	1	-	-	-	-	-	-	-	-	-	5.76
2038	4			-	29.51	0.13	15.08	8.06	-	-	-	-	1	-	-	-	-	-	-	-	-	5.66
2038	5			10.30	-	1.75	5.99	8.06	-	-	-	-	-	1	-	-	-	-	-	-	-	5.69
2038	6			16.76	-	6.64	0.86	8.06	-	-	-	-	-	-	1	-	-	-	-	-	-	5.90
2038	7			21.27	-	14.01	0.01	8.06	-	-	-	-	-	-	-	1	-	-	-	-	-	6.00
2038	8			18.79	-	11.18	0.07	8.06	-	-	-	-	-	-	-	-	1	-	-	-	-	5.96
2038	9			15.24	-	4.84	2.24	8.06	-	-	-	-	-	-	-	-	-	1	-	-	-	5.85
2038	10			-	24.95	0.37	12.63	8.06	-	-	-	-	-	-	-	-	-	-	1	-	-	5.68
2038	11			-	39.87	0.02	22.57	8.06	-	-	-	-	-	-	-	-	-	-	-	1	-	5.78
2038	12			-	52.21	-	32.51	8.06	-	-	-	-	-	-	-	-	-	-	-	-	1	5.85
2039	1			-	49.39	-	32.54	8.07	-	1	-	-	-	-	-	-	-	-	-	-	-	5.87
2039	2			-	52.46	-	33.49	8.07	-	-	1	-	-	-	-	-	-	-	-	-	-	5.83
2039	3			-	40.59	0.04	23.14	8.07	-	-	-	1	-	-	-	-	-	-	-	-	-	5.77
2039	4			-	29.51	0.13	15.08	8.07	-	-	-	-	1	-	-	-	-	-	-	-	-	5.66
2039	5			10.30	-	1.75	5.99	8.07	-	-	-	-	-	1	-	-	-	-	-	-	-	5.70
2039	6			16.76	-	6.64	0.86	8.07	-	-	-	-	-	-	1	-	-	-	-	-	-	5.91
2039	7			21.27	-	14.01	0.01	8.07	-	-	-	-	-	-	-	1	-	-	-	-	-	6.01
2039	8			18.79	-	11.18	0.07	8.07	-	-	-	-	-	-	-	-	1	-	-	-	-	5.96
2039	9			15.24	-	4.84	2.24	8.07	-	-	-	-	-	-	-	-	-	1	-	-	-	5.85
2039	10			-	24.95	0.37	12.63	8.07	-	-	-	-	-	-	-	-	-	-	1	-	-	5.69
2039	11			-	39.87	0.02	22.57	8.07	-	-	-	-	-	-	-	-	-	-	-	1	-	5.78
2039	12			-	52.21	-	32.51	8.07	-	-	-	-	-	-	-	-	-	-	-	-	1	5.85
2040	1			-	49.39	-	32.54	8.08	-	1	-	-	-	-	-	-	-	-	-	-	-	5.88
2040	2			-	52.46	-	33.49	8.08	-	-	1	-	-	-	-	-	-	-	-	-	-	5.84
2040	3			-	40.59	0.04	23.14	8.08	-	-	-	1	-	-	-	-	-	-	-	-	-	5.77
2040	4			-	29.51	0.13	15.08	8.08	-	-	-	-	1	-	-	-	-	-	-	-	-	5.67
2040	5			10.30	-	1.75	5.99	8.08	-	-	-	-	-	1	-	-	-	-	-	-	-	5.70

2040	6			16.76	-	6.64	0.86	8.08	-	-	-	-	-	-	1	-	-	-	-	-	-	5.91
2040	7			21.27	-	14.01	0.01	8.08	-	-	-	-	-	-	-	1	-	-	-	-	-	6.01
2040	8			18.79	-	11.18	0.07	8.08	-	-	-	-	-	-	-	-	1	-	-	-	-	5.97
2040	9			15.24	-	4.84	2.24	8.08	-	-	-	-	-	-	-	-	-	1	-	-	-	5.85
2040	10			-	24.95	0.37	12.63	8.08	-	-	-	-	-	-	-	-	-	-	1	-	-	5.69
2040	11			-	39.87	0.02	22.57	8.08	-	-	-	-	-	-	-	-	-	-	-	1	-	5.79
2040	12			-	52.21	-	32.51	8.08	-	-	-	-	-	-	-	-	-	-	-	-	1	5.86

Schedule C-7. Black Hills Power: Variable Statistical Values for Demand Model

Black Hills Power **Confidential Appendix C**

Black Hills Power: Variable Statistical Values for Demand Model **Schedule C-7**

Variable	Coefficient	Standard Error	P Value	R2 = 0.9168
cdd60	0.009	0.001	0.000	
hdd60	0.003	0.000	0.000	
mnthcdd60perday	0.010	0.002	0.000	
mnthhdd60perday	0.004	0.001	0.000	
lntotPI	0.338	0.038	0.000	
weekend	-0.023	0.011	0.043	
m2	-0.052	0.012	0.000	
m3	-0.042	0.014	0.003	
m4	-0.081	0.016	0.000	
m5	-0.032	0.020	0.118	
m6	0.093	0.027	0.001	
m7	0.080	0.032	0.014	
m8	0.089	0.030	0.003	
m9	0.062	0.026	0.017	
m10	-0.034	0.019	0.075	
m11	-0.022	0.016	0.165	
m12	-0.028	0.012	0.019	
_cons	2.867	0.293	0.000	

Schedule C-8. Black Hills Power: Base Monthly Customer Class Sales Forecast and Demand Forecast

Black Hills Power | **Confidential Appendix C**

Black Hills Power: Base Monthly Customer Class Sales Forecast and Demand Forecast | **Schedule C-8**

Year	Month	Residential Use per Customer (MWh)	Residential Customers	Residential Sales (MWh)	Commercial Use per Customer (MWh)	Commercial Customers	Commercial Sales (MWh)	Municipal Sales (MWh)	Industrial Sales (MWh)	Base System Demand (MW)
2020	Jan	1.03	58,786.05	60,493.14	5.14	13,146.33	69,129.30	1,547.95	39,867.48	317.51
2020	Feb	0.94	58,818.30	55,315.87	4.87	13,098.48	62,779.71	1,390.61	36,121.81	305.13
2020	Mar	0.88	58,909.91	51,957.19	4.84	13,130.57	63,292.44	1,426.15	35,702.44	285.67
2020	Apr	0.74	58,921.04	43,701.74	4.54	13,200.41	61,130.15	1,421.49	36,027.70	257.67
2020	May	0.64	58,968.14	37,672.53	4.40	13,320.44	57,429.45	1,529.26	36,719.93	266.61
2020	Jun	0.61	59,026.32	35,718.51	4.80	13,404.30	61,914.85	1,918.49	38,438.75	328.90
2020	Jul	0.74	59,024.07	43,584.65	5.37	13,444.29	69,524.92	2,412.12	36,376.63	363.07
2020	Aug	0.81	59,155.26	47,984.38	5.70	13,531.08	77,796.64	2,505.00	40,674.51	348.27
2020	Sep	0.69	59,220.23	40,573.10	5.20	13,444.80	66,096.30	2,204.80	40,409.74	310.77
2020	Oct	0.60	59,239.71	35,248.02	4.65	13,362.47	59,782.04	1,716.07	40,256.46	264.47
2020	Nov	0.69	59,251.86	40,605.34	4.44	13,283.47	60,577.14	1,329.85	40,598.25	290.08
2020	Dec	0.90	59,341.55	53,553.78	5.02	13,172.75	63,113.93	1,467.50	41,879.30	311.26
2021	Jan	1.02	59,343.36	60,741.07	5.13	13,174.16	69,192.78	1,528.26	39,867.48	319.08
2021	Feb	0.94	59,378.91	55,545.37	4.86	13,126.35	62,841.22	1,372.93	36,121.81	306.67
2021	Mar	0.88	59,474.46	52,175.46	4.84	13,158.65	63,352.18	1,408.01	35,702.44	287.01
2021	Apr	0.74	59,488.65	43,887.51	4.53	13,228.80	61,191.08	1,403.41	36,027.70	258.83
2021	May	0.64	59,539.22	37,834.57	4.40	13,349.23	57,488.55	1,509.80	36,719.93	267.84
2021	Jun	0.60	59,600.97	35,873.97	4.80	13,433.44	61,980.80	1,894.09	38,438.75	330.55
2021	Jul	0.73	59,601.71	43,776.54	5.37	13,473.65	69,603.16	2,381.44	36,376.63	364.96
2021	Aug	0.81	59,737.14	48,198.03	5.69	13,560.80	77,886.95	2,473.14	40,674.51	350.05
2021	Sep	0.68	59,805.77	40,755.81	5.20	13,474.48	66,174.96	2,176.76	40,409.74	312.29
2021	Oct	0.59	59,828.42	35,408.54	4.64	13,392.12	59,854.41	1,694.24	40,256.46	265.64
2021	Nov	0.68	59,843.71	40,792.28	4.43	13,313.09	60,651.69	1,312.93	40,598.25	291.42
2021	Dec	0.90	59,937.21	53,802.95	5.01	13,202.27	63,194.93	1,448.83	41,879.30	312.76
2022	Jan	1.02	59,942.93	61,027.66	5.13	13,203.87	69,285.39	1,508.82	39,867.48	320.71
2022	Feb	0.93	59,979.70	55,808.23	4.86	13,156.00	62,928.20	1,355.46	36,121.81	308.27
2022	Mar	0.87	60,077.02	52,423.08	4.84	13,188.41	63,434.56	1,390.10	35,702.44	288.40
2022	Apr	0.73	60,092.26	44,096.46	4.53	13,258.76	61,272.69	1,385.56	36,027.70	260.03
2022	May	0.63	60,144.21	38,015.27	4.40	13,379.50	57,565.76	1,490.60	36,719.93	269.11
2022	Jun	0.60	60,207.39	36,045.77	4.80	13,463.94	62,064.71	1,870.00	38,438.75	332.27
2022	Jul	0.73	60,209.05	43,986.85	5.36	13,504.30	69,700.40	2,351.14	36,376.63	366.93
2022	Aug	0.80	60,346.68	48,430.24	5.69	13,591.68	77,996.61	2,441.68	40,674.51	351.89
2022	Sep	0.68	60,416.87	40,952.74	5.19	13,505.21	66,268.42	2,149.07	40,409.74	313.87
2022	Oct	0.59	60,440.61	35,580.14	4.64	13,422.70	59,938.52	1,672.69	40,256.46	266.87
2022	Nov	0.68	60,456.87	40,990.54	4.43	13,343.53	60,736.63	1,296.23	40,598.25	292.83
2022	Dec	0.89	60,552.25	54,065.28	5.01	13,232.50	63,285.38	1,430.40	41,879.30	314.33
2023	Jan	1.01	60,552.20	61,319.28	5.13	13,233.82	69,380.98	1,489.63	39,867.48	322.26
2023	Feb	0.93	60,582.69	56,068.77	4.85	13,185.52	63,012.53	1,338.22	36,121.81	309.79
2023	Mar	0.87	60,674.34	52,662.03	4.83	13,217.69	63,509.30	1,372.42	35,702.44	289.72
2023	Apr	0.73	60,683.07	44,292.59	4.52	13,287.86	61,341.76	1,367.94	36,027.70	261.17
2023	May	0.63	60,728.87	38,180.16	4.39	13,408.55	57,626.54	1,471.64	36,719.93	270.32

2023	Jun	0.60	60,786.06	36,198.19	4.79	13,492.84	62,125.79	1,846.21	38,438.75	333.90
2023	Jul	0.73	60,781.13	44,168.07	5.36	13,532.94	69,765.44	2,321.24	36,376.63	368.80
2023	Aug	0.80	60,913.44	48,624.47	5.68	13,620.18	78,063.77	2,410.62	40,674.51	353.65
2023	Sep	0.67	60,977.66	41,112.52	5.19	13,533.19	66,320.31	2,121.73	40,409.74	315.36
2023	Oct	0.59	60,995.05	35,715.08	4.63	13,450.19	59,980.53	1,651.42	40,256.46	268.03
2023	Nov	0.67	61,004.82	41,141.53	4.43	13,370.54	60,774.44	1,279.74	40,598.25	294.15
2023	Dec	0.89	61,094.48	54,258.58	5.00	13,258.96	63,320.79	1,412.21	41,879.30	315.82
2024	Jan	1.01	61,088.37	61,532.48	5.12	13,259.98	69,415.43	1,470.68	39,867.48	323.86
2024	Feb	0.92	61,119.66	56,264.16	4.85	13,211.61	63,045.10	1,321.20	36,121.81	311.35
2024	Mar	0.86	61,212.70	52,846.06	4.83	13,243.87	63,540.27	1,354.96	35,702.44	291.08
2024	Apr	0.73	61,222.04	44,447.76	4.52	13,314.22	61,372.65	1,350.54	36,027.70	262.34
2024	May	0.63	61,268.83	38,314.27	4.39	13,435.16	57,655.79	1,452.92	36,719.93	271.56
2024	Jun	0.59	61,327.05	36,325.66	4.78	13,519.66	62,157.82	1,822.73	38,438.75	335.57
2024	Jul	0.72	61,322.61	44,323.97	5.35	13,559.87	69,802.71	2,291.71	36,376.63	370.72
2024	Aug	0.79	61,456.68	48,796.56	5.67	13,647.31	78,105.92	2,379.96	40,674.51	355.45
2024	Sep	0.67	61,522.00	41,258.37	5.18	13,560.18	66,356.42	2,094.74	40,409.74	316.90
2024	Oct	0.58	61,540.07	35,842.11	4.63	13,477.02	60,013.17	1,630.41	40,256.46	269.22
2024	Nov	0.67	61,550.52	41,288.25	4.42	13,397.24	60,807.53	1,263.47	40,598.25	295.52
2024	Dec	0.88	61,641.46	54,452.49	5.00	13,285.46	63,356.17	1,394.24	41,879.30	317.35
2025	Jan	1.00	61,635.75	61,752.80	5.11	13,286.52	69,454.93	1,451.97	39,867.48	325.45
2025	Feb	0.92	61,667.27	56,465.60	4.84	13,238.05	63,081.88	1,304.39	36,121.81	312.91
2025	Mar	0.86	61,761.09	53,035.21	4.82	13,270.37	63,574.77	1,337.72	35,702.44	292.44
2025	Apr	0.72	61,770.45	44,606.81	4.51	13,340.85	61,406.51	1,333.36	36,027.70	263.51
2025	May	0.62	61,817.48	38,451.28	4.38	13,462.03	57,687.60	1,434.44	36,719.93	272.81
2025	Jun	0.59	61,876.22	36,455.54	4.78	13,546.68	62,192.04	1,799.54	38,438.75	337.25
2025	Jul	0.72	61,871.62	44,482.37	5.34	13,586.97	69,842.03	2,262.56	36,376.63	372.64
2025	Aug	0.79	62,006.77	48,970.84	5.67	13,674.59	78,149.96	2,349.68	40,674.51	357.26
2025	Sep	0.67	62,072.63	41,405.70	5.17	13,587.27	66,393.57	2,068.10	40,409.74	318.44
2025	Oct	0.58	62,090.80	35,970.07	4.62	13,503.96	60,046.38	1,609.67	40,256.46	270.42
2025	Nov	0.67	62,101.22	41,435.57	4.41	13,424.01	60,840.73	1,247.39	40,598.25	296.89
2025	Dec	0.88	62,192.91	54,646.73	4.99	13,312.01	63,391.25	1,376.51	41,879.30	318.88
2026	Jan	1.00	62,187.57	61,973.50	5.10	13,313.09	69,494.08	1,433.50	39,867.48	327.01
2026	Feb	0.91	62,219.79	56,667.79	4.83	13,264.54	63,118.68	1,287.80	36,121.81	314.44
2026	Mar	0.85	62,314.86	53,225.45	4.81	13,296.94	63,609.62	1,320.71	35,702.44	293.77
2026	Apr	0.72	62,324.78	44,767.15	4.50	13,367.58	61,441.09	1,316.40	36,027.70	264.65
2026	May	0.62	62,372.71	38,589.79	4.38	13,489.03	57,720.38	1,416.19	36,719.93	274.02
2026	Jun	0.59	62,432.40	36,587.11	4.77	13,573.88	62,227.73	1,776.65	38,438.75	338.89
2026	Jul	0.72	62,428.23	44,643.26	5.34	13,614.26	69,883.45	2,233.78	36,376.63	374.52
2026	Aug	0.79	62,565.07	49,148.35	5.66	13,702.08	78,196.70	2,319.80	40,674.51	359.02
2026	Sep	0.66	62,631.94	41,556.06	5.17	13,614.61	66,433.51	2,041.79	40,409.74	319.94
2026	Oct	0.58	62,650.70	36,100.92	4.62	13,531.15	60,082.28	1,589.20	40,256.46	271.58
2026	Nov	0.66	62,661.69	41,586.63	4.41	13,451.06	60,877.10	1,231.53	40,598.25	298.23
2026	Dec	0.87	62,754.68	54,846.36	4.98	13,338.86	63,430.04	1,359.00	41,879.30	320.38
2027	Jan	0.99	62,748.34	62,198.97	5.10	13,339.89	69,536.23	1,415.27	39,867.48	328.53
2027	Feb	0.91	62,779.52	56,872.73	4.83	13,291.18	63,157.05	1,271.42	36,121.81	315.92
2027	Mar	0.85	62,874.07	53,416.80	4.81	13,323.58	63,644.79	1,303.91	35,702.44	295.07
2027	Apr	0.71	62,882.71	44,927.12	4.50	13,394.30	61,474.83	1,299.65	36,027.70	265.77
2027	May	0.62	62,929.74	38,726.84	4.37	13,515.93	57,751.27	1,398.18	36,719.93	275.21

2027	Jun	0.58	62,988.58	36,716.26	4.77	13,600.88	62,260.20	1,754.05	38,438.75	340.49
2027	Jul	0.71	62,983.00	44,799.85	5.33	13,641.28	69,919.71	2,205.37	36,376.63	376.35
2027	Aug	0.78	63,119.73	49,319.71	5.65	13,729.21	78,236.26	2,290.29	40,674.51	360.74
2027	Sep	0.66	63,185.80	41,700.03	5.16	13,641.50	66,465.97	2,015.82	40,409.74	321.41
2027	Oct	0.57	63,203.40	36,225.24	4.61	13,557.81	60,110.44	1,568.98	40,256.46	272.72
2027	Nov	0.66	63,213.17	41,728.95	4.40	13,477.50	60,904.50	1,215.86	40,598.25	299.53
2027	Dec	0.87	63,305.59	55,032.86	4.98	13,365.00	63,458.06	1,341.71	41,879.30	321.83
2028	Jan	0.99	63,296.29	62,407.61	5.09	13,365.91	69,565.09	1,397.27	39,867.48	330.02
2028	Feb	0.90	63,326.18	57,062.09	4.82	13,317.02	63,182.86	1,255.25	36,121.81	317.38
2028	Mar	0.85	63,419.98	53,593.33	4.80	13,349.42	63,668.06	1,287.32	35,702.44	296.33
2028	Apr	0.71	63,427.18	45,074.51	4.49	13,420.20	61,496.71	1,283.12	36,027.70	266.86
2028	May	0.61	63,473.04	38,852.95	4.36	13,541.99	57,770.86	1,380.39	36,719.93	276.37
2028	Jun	0.58	63,530.82	36,834.89	4.76	13,627.03	62,280.31	1,731.74	38,438.75	342.05
2028	Jul	0.71	63,523.61	44,943.49	5.32	13,667.43	69,941.67	2,177.32	36,376.63	378.14
2028	Aug	0.78	63,660.00	49,476.65	5.64	13,755.45	78,259.52	2,261.16	40,674.51	362.42
2028	Sep	0.66	63,725.12	41,831.73	5.15	13,667.50	66,484.58	1,990.18	40,409.74	322.84
2028	Oct	0.57	63,741.29	36,338.76	4.60	13,583.58	60,126.17	1,549.02	40,256.46	273.84
2028	Nov	0.66	63,749.55	41,858.69	4.39	13,503.03	60,919.21	1,200.40	40,598.25	300.80
2028	Dec	0.86	63,841.18	55,202.59	4.97	13,390.26	63,472.65	1,324.65	41,879.30	323.26
2029	Jan	0.98	63,829.18	62,597.48	5.08	13,391.04	69,579.28	1,379.49	39,867.48	331.49
2029	Feb	0.90	63,858.29	57,234.81	4.81	13,342.02	63,195.33	1,239.28	36,121.81	318.82
2029	Mar	0.84	63,951.78	53,754.59	4.79	13,374.42	63,679.05	1,270.95	35,702.44	297.59
2029	Apr	0.71	63,957.94	45,209.37	4.48	13,445.29	61,506.86	1,266.80	36,027.70	267.94
2029	May	0.61	64,003.09	38,968.52	4.36	13,567.25	57,779.77	1,362.83	36,719.93	277.51
2029	Jun	0.58	64,060.31	36,943.86	4.75	13,652.40	62,289.21	1,709.71	38,438.75	343.59
2029	Jul	0.70	64,052.00	45,075.74	5.31	13,692.83	69,951.19	2,149.62	36,376.63	379.91
2029	Aug	0.77	64,188.43	49,621.39	5.63	13,780.94	78,269.18	2,232.39	40,674.51	364.08
2029	Sep	0.65	64,252.98	41,953.39	5.14	13,692.79	66,492.07	1,964.87	40,409.74	324.26
2029	Oct	0.57	64,268.24	36,443.83	4.59	13,608.65	60,132.11	1,529.32	40,256.46	274.94
2029	Nov	0.65	64,275.47	41,979.00	4.39	13,527.92	60,924.57	1,185.13	40,598.25	302.06
2029	Dec	0.86	64,366.87	55,360.41	4.96	13,414.89	63,477.57	1,307.80	41,879.30	324.67
2030	Jan	0.98	64,352.94	62,774.68	5.07	13,415.58	69,583.37	1,361.95	39,867.48	332.91
2030	Feb	0.89	64,381.48	57,396.08	4.80	13,366.43	63,198.64	1,223.52	36,121.81	320.21
2030	Mar	0.84	64,475.00	53,905.47	4.78	13,398.86	63,681.69	1,254.78	35,702.44	298.80
2030	Apr	0.70	64,480.41	45,335.70	4.48	13,469.81	61,508.95	1,250.69	36,027.70	268.99
2030	May	0.61	64,525.25	39,076.99	4.35	13,591.97	57,781.31	1,345.50	36,719.93	278.62
2030	Jun	0.57	64,582.14	37,046.25	4.74	13,677.24	62,290.40	1,687.97	38,438.75	345.08
2030	Jul	0.70	64,573.02	45,200.12	5.30	13,717.70	69,951.96	2,122.28	36,376.63	381.62
2030	Aug	0.77	64,709.75	49,757.70	5.62	13,805.95	78,269.52	2,204.00	40,674.51	365.69
2030	Sep	0.65	64,774.15	42,068.19	5.13	13,717.60	66,491.73	1,939.87	40,409.74	325.63
2030	Oct	0.56	64,788.73	36,543.11	4.59	13,633.28	60,131.41	1,509.87	40,256.46	276.00
2030	Nov	0.65	64,795.28	42,092.87	4.38	13,552.37	60,923.36	1,170.05	40,598.25	303.28
2030	Dec	0.86	64,886.68	55,509.94	4.95	13,439.08	63,475.75	1,291.16	41,879.30	326.03
2031	Jan	0.97	64,870.53	62,942.20	5.06	13,439.68	69,579.88	1,344.62	39,867.48	334.24
2031	Feb	0.89	64,897.94	57,548.04	4.79	13,390.39	63,194.50	1,207.95	36,121.81	321.51
2031	Mar	0.83	64,990.84	54,047.05	4.77	13,422.80	63,676.87	1,238.82	35,702.44	299.93
2031	Apr	0.70	64,995.00	45,453.86	4.47	13,493.83	61,503.38	1,234.78	36,027.70	269.96
2031	May	0.60	65,038.77	39,178.00	4.34	13,616.14	57,775.27	1,328.38	36,719.93	279.66

2031	Jun	0.57	65,094.80	37,141.24	4.73	13,701.49	62,283.06	1,666.49	38,438.75	346.48
2031	Jul	0.70	65,084.25	45,315.08	5.29	13,741.97	69,942.50	2,095.28	36,376.63	383.22
2031	Aug	0.76	65,220.76	49,883.25	5.61	13,830.30	78,257.79	2,175.96	40,674.51	367.19
2031	Sep	0.65	65,284.24	42,173.42	5.12	13,741.73	66,480.91	1,915.20	40,409.74	326.91
2031	Oct	0.56	65,297.63	36,633.79	4.58	13,657.20	60,120.88	1,490.66	40,256.46	276.99
2031	Nov	0.65	65,302.92	42,196.49	4.37	13,576.08	60,911.99	1,155.17	40,598.25	304.42
2031	Dec	0.85	65,393.66	55,645.42	4.94	13,462.54	63,462.86	1,274.74	41,879.30	327.31
2032	Jan	0.97	65,374.20	63,092.71	5.05	13,462.99	69,563.26	1,327.52	39,867.48	335.51
2032	Feb	0.88	65,400.02	57,684.09	4.79	13,413.54	63,177.78	1,192.59	36,121.81	322.76
2032	Mar	0.83	65,491.83	54,173.30	4.76	13,445.93	63,660.07	1,223.06	35,702.44	301.02
2032	Apr	0.70	65,494.14	45,558.73	4.46	13,516.99	61,485.75	1,219.07	36,027.70	270.90
2032	May	0.60	65,536.50	39,267.34	4.33	13,639.42	57,757.59	1,311.49	36,719.93	280.65
2032	Jun	0.57	65,591.15	37,224.92	4.72	13,724.84	62,262.83	1,645.30	38,438.75	347.82
2032	Jul	0.69	65,578.64	45,415.88	5.28	13,765.29	69,917.93	2,068.63	36,376.63	384.76
2032	Aug	0.76	65,714.37	49,992.84	5.60	13,853.70	78,228.80	2,148.28	40,674.51	368.64
2032	Sep	0.64	65,776.57	42,264.93	5.11	13,764.88	66,455.09	1,890.84	40,409.74	328.14
2032	Oct	0.56	65,788.23	36,712.25	4.57	13,680.13	60,096.73	1,471.70	40,256.46	277.95
2032	Nov	0.64	65,791.75	42,285.69	4.36	13,598.78	60,886.60	1,140.48	40,598.25	305.52
2032	Dec	0.85	65,881.28	55,761.46	4.93	13,484.98	63,434.90	1,258.52	41,879.30	328.53
2033	Jan	0.96	65,858.04	63,220.83	5.04	13,485.26	69,529.67	1,310.63	39,867.48	336.76
2033	Feb	0.88	65,882.16	57,799.54	4.77	13,435.62	63,145.14	1,177.42	36,121.81	323.98
2033	Mar	0.82	65,972.83	54,280.25	4.75	13,467.99	63,628.26	1,207.51	35,702.44	302.08
2033	Apr	0.69	65,973.27	45,647.37	4.45	13,539.08	61,453.27	1,203.56	36,027.70	271.82
2033	May	0.60	66,014.05	39,342.59	4.32	13,661.63	57,726.03	1,294.81	36,719.93	281.63
2033	Jun	0.56	66,067.20	37,295.20	4.71	13,747.09	62,227.53	1,624.37	38,438.75	349.13
2033	Jul	0.69	66,052.78	45,500.35	5.27	13,787.53	69,876.01	2,042.32	36,376.63	386.27
2033	Aug	0.76	66,187.59	50,084.39	5.59	13,875.99	78,180.39	2,120.96	40,674.51	370.05
2033	Sep	0.64	66,248.41	42,341.16	5.10	13,786.95	66,412.94	1,866.78	40,409.74	329.34
2033	Oct	0.56	66,258.27	36,777.43	4.56	13,701.97	60,057.85	1,452.98	40,256.46	278.88
2033	Nov	0.64	66,259.97	42,359.57	4.35	13,620.41	60,846.50	1,125.97	40,598.25	306.58
2033	Dec	0.84	66,348.30	55,857.35	4.92	13,506.34	63,391.25	1,242.51	41,879.30	329.73
2034	Jan	0.95	66,321.87	63,326.65	5.03	13,506.49	69,479.32	1,293.96	39,867.48	338.00
2034	Feb	0.87	66,345.08	57,895.34	4.76	13,456.73	63,097.47	1,162.44	36,121.81	325.19
2034	Mar	0.82	66,435.24	54,369.28	4.74	13,489.08	63,582.69	1,192.15	35,702.44	303.13
2034	Apr	0.69	66,434.61	45,721.50	4.44	13,560.23	61,407.73	1,188.26	36,027.70	272.72
2034	May	0.59	66,474.47	39,405.79	4.31	13,682.92	57,682.62	1,278.34	36,719.93	282.59
2034	Jun	0.56	66,526.92	37,354.49	4.70	13,768.46	62,180.01	1,603.71	38,438.75	350.43
2034	Jul	0.69	66,511.31	45,571.94	5.26	13,808.91	69,820.58	2,016.34	36,376.63	387.75
2034	Aug	0.75	66,645.92	50,162.32	5.57	13,897.46	78,117.37	2,093.98	40,674.51	371.44
2034	Sep	0.64	66,706.01	42,406.32	5.09	13,808.23	66,358.85	1,843.04	40,409.74	330.53
2034	Oct	0.55	66,714.85	36,833.43	4.55	13,723.07	60,008.84	1,434.50	40,256.46	279.81
2034	Nov	0.64	66,715.43	42,423.37	4.34	13,641.33	60,796.68	1,111.65	40,598.25	307.64
2034	Dec	0.84	66,803.29	55,940.57	4.91	13,527.03	63,337.81	1,226.71	41,879.30	330.91
2035	Jan	0.95	66,774.05	63,418.47	5.02	13,527.06	69,418.32	1,277.50	39,867.48	339.25
2035	Feb	0.87	66,795.84	57,977.95	4.75	13,477.16	63,039.65	1,147.66	36,121.81	326.42
2035	Mar	0.81	66,885.14	54,445.63	4.73	13,509.50	63,527.45	1,176.98	35,702.44	304.20
2035	Apr	0.68	66,882.97	45,784.66	4.43	13,580.69	61,352.45	1,173.14	36,027.70	273.65
2035	May	0.59	66,921.63	39,459.36	4.30	13,703.49	57,629.84	1,262.08	36,719.93	283.57

2035	Jun	0.56	66,972.84	37,404.38	4.69	13,789.10	62,122.13	1,583.31	38,438.75	351.75
2035	Jul	0.68	66,955.59	45,631.78	5.24	13,829.54	69,752.87	1,990.69	36,376.63	389.27
2035	Aug	0.75	67,089.63	50,227.09	5.56	13,918.13	78,040.32	2,067.34	40,674.51	372.86
2035	Sep	0.63	67,148.59	42,460.11	5.07	13,828.71	66,292.64	1,819.60	40,409.74	331.74
2035	Oct	0.55	67,156.02	36,879.33	4.53	13,743.36	59,948.82	1,416.25	40,256.46	280.75
2035	Nov	0.63	67,155.05	42,475.25	4.33	13,661.42	60,735.52	1,097.51	40,598.25	308.72
2035	Dec	0.83	67,241.95	56,007.69	4.89	13,546.89	63,272.16	1,211.11	41,879.30	332.12
2036	Jan	0.94	67,210.16	63,492.37	5.00	13,546.81	69,344.07	1,261.25	39,867.48	340.47
2036	Feb	0.86	67,231.24	58,044.74	4.74	13,496.79	62,969.80	1,133.06	36,121.81	327.61
2036	Mar	0.81	67,320.23	54,507.66	4.72	13,529.14	63,461.30	1,162.01	35,702.44	305.24
2036	Apr	0.68	67,317.22	45,836.25	4.42	13,600.40	61,286.92	1,158.22	36,027.70	274.54
2036	May	0.59	67,355.30	39,503.32	4.29	13,723.34	57,567.76	1,246.02	36,719.93	284.51
2036	Jun	0.56	67,406.06	37,445.64	4.68	13,809.03	62,054.61	1,563.17	38,438.75	353.03
2036	Jul	0.68	67,387.80	45,681.48	5.23	13,849.48	69,674.62	1,965.37	36,376.63	390.73
2036	Aug	0.74	67,521.87	50,281.18	5.54	13,938.18	77,952.01	2,041.05	40,674.51	374.24
2036	Sep	0.63	67,580.37	42,505.30	5.06	13,848.58	66,217.38	1,796.45	40,409.74	332.92
2036	Oct	0.55	67,586.94	36,918.10	4.52	13,763.07	59,880.99	1,398.24	40,256.46	281.66
2036	Nov	0.63	67,585.13	42,519.36	4.32	13,680.98	60,666.99	1,083.55	40,598.25	309.76
2036	Dec	0.83	67,671.75	56,065.17	4.88	13,566.24	63,199.19	1,195.70	41,879.30	333.29
2037	Jan	0.94	67,637.62	63,555.52	4.99	13,566.08	69,261.90	1,245.21	39,867.48	341.61
2037	Feb	0.86	67,657.62	58,101.43	4.73	13,515.93	62,892.35	1,118.65	36,121.81	328.73
2037	Mar	0.81	67,745.88	54,559.85	4.70	13,548.26	63,387.76	1,147.23	35,702.44	306.21
2037	Apr	0.68	67,741.62	45,879.31	4.40	13,619.56	61,213.81	1,143.49	36,027.70	275.38
2037	May	0.58	67,778.65	39,539.69	4.28	13,742.62	57,498.36	1,230.17	36,719.93	285.41
2037	Jun	0.55	67,828.44	37,479.38	4.66	13,828.38	61,979.01	1,543.28	38,438.75	354.23
2037	Jul	0.67	67,808.84	45,721.83	5.21	13,868.83	69,586.77	1,940.37	36,376.63	392.11
2037	Aug	0.74	67,942.51	50,324.67	5.53	13,957.59	77,852.60	2,015.09	40,674.51	375.53
2037	Sep	0.63	68,000.07	42,541.25	5.05	13,867.81	66,132.45	1,773.60	40,409.74	334.02
2037	Oct	0.54	68,005.45	36,948.65	4.51	13,782.11	59,804.33	1,380.45	40,256.46	282.51
2037	Nov	0.63	68,002.41	42,553.81	4.30	13,699.86	60,589.40	1,069.76	40,598.25	310.74
2037	Dec	0.82	68,088.26	56,109.51	4.87	13,584.91	63,116.32	1,180.49	41,879.30	334.38
2038	Jan	0.93	68,051.97	63,603.94	4.98	13,584.64	69,168.84	1,229.37	39,867.48	342.69
2038	Feb	0.85	68,071.31	58,145.05	4.71	13,534.40	62,805.13	1,104.42	36,121.81	329.79
2038	Mar	0.80	68,159.40	54,600.22	4.69	13,566.75	63,305.36	1,132.64	35,702.44	307.14
2038	Apr	0.67	68,154.33	45,912.73	4.39	13,638.11	61,132.24	1,128.94	36,027.70	276.18
2038	May	0.58	68,190.80	39,568.04	4.26	13,761.30	57,421.36	1,214.52	36,719.93	286.25
2038	Jun	0.55	68,240.18	37,505.86	4.65	13,847.14	61,895.44	1,523.65	38,438.75	355.37
2038	Jul	0.67	68,219.75	45,753.67	5.20	13,887.61	69,490.12	1,915.69	36,376.63	393.41
2038	Aug	0.74	68,353.38	50,359.09	5.51	13,976.46	77,743.76	1,989.45	40,674.51	376.76
2038	Sep	0.62	68,410.57	42,569.90	5.03	13,886.53	66,039.91	1,751.04	40,409.74	335.07
2038	Oct	0.54	68,415.27	36,973.13	4.49	13,800.69	59,721.22	1,362.89	40,256.46	283.32
2038	Nov	0.62	68,411.42	42,581.51	4.29	13,718.28	60,505.55	1,056.16	40,598.25	311.67
2038	Dec	0.82	68,497.07	56,145.45	4.85	13,603.14	63,027.16	1,165.48	41,879.30	335.42
2039	Jan	0.93	68,459.26	63,643.49	4.96	13,602.82	69,069.36	1,213.73	39,867.48	343.75
2039	Feb	0.85	68,478.13	58,180.69	4.70	13,552.48	62,711.98	1,090.37	36,121.81	330.81
2039	Mar	0.80	68,566.09	54,633.19	4.68	13,584.85	63,217.48	1,118.23	35,702.44	308.03
2039	Apr	0.67	68,560.40	45,940.06	4.38	13,656.28	61,045.46	1,114.58	36,027.70	276.95
2039	May	0.58	68,596.57	39,591.27	4.25	13,779.60	57,339.49	1,199.08	36,719.93	287.07

2039	Jun	0.55	68,645.65	37,527.57	4.64	13,865.53	61,806.72	1,504.27	38,438.75	356.47
2039	Jul	0.67	68,624.44	45,779.70	5.18	13,906.03	69,387.71	1,891.32	36,376.63	394.68
2039	Aug	0.73	68,758.34	50,387.36	5.49	13,994.97	77,628.67	1,964.15	40,674.51	377.94
2039	Sep	0.62	68,815.28	42,593.43	5.02	13,904.89	65,942.12	1,728.77	40,409.74	336.08
2039	Oct	0.54	68,819.35	36,993.24	4.48	13,818.90	59,633.40	1,345.56	40,256.46	284.11
2039	Nov	0.62	68,814.95	42,604.32	4.28	13,736.37	60,417.22	1,042.72	40,598.25	312.57
2039	Dec	0.82	68,900.52	56,175.04	4.84	13,621.05	62,933.38	1,150.65	41,879.30	336.43
2040	Jan	0.92	68,861.63	63,676.25	4.95	13,620.69	68,965.06	1,198.29	39,867.48	344.81
2040	Feb	0.85	68,880.35	58,210.41	4.68	13,570.28	62,614.55	1,076.50	36,121.81	331.85
2040	Mar	0.79	68,968.63	54,660.94	4.66	13,602.67	63,125.79	1,104.01	35,702.44	308.94
2040	Apr	0.67	68,962.64	45,963.21	4.36	13,674.20	60,955.17	1,100.40	36,027.70	277.73
2040	May	0.57	68,998.76	39,611.10	4.24	13,797.67	57,254.51	1,183.82	36,719.93	287.90
2040	Jun	0.54	69,047.87	37,546.22	4.62	13,883.69	61,714.88	1,485.14	38,438.75	357.59
2040	Jul	0.66	69,026.34	45,802.30	5.17	13,924.24	69,281.90	1,867.26	36,376.63	395.96
2040	Aug	0.73	69,160.76	50,412.05	5.48	14,013.28	77,509.95	1,939.16	40,674.51	379.15
2040	Sep	0.62	69,217.77	42,614.13	5.00	13,923.07	65,841.51	1,706.78	40,409.74	337.10
2040	Oct	0.53	69,221.66	37,011.11	4.47	13,836.97	59,543.39	1,328.44	40,256.46	284.90
2040	Nov	0.62	69,216.98	42,624.76	4.27	13,754.32	60,326.80	1,029.46	40,598.25	313.48
2040	Dec	0.81	69,302.77	56,201.78	4.82	13,638.84	62,837.57	1,136.01	41,879.30	337.45

Schedule C-9. Black Hills Power: Base Annual Customer Class Sales Forecast and Demand Forecast

Black Hills Power **Confidential Appendix C**

Black Hills Power: Base Annual Customer Class Sales Forecast and Demand Forecast **Schedule C-9**

Year	Residential Use per Customer (MWh)	Residential Customers	Residential Sales (MWh)	Commercial Use per Customer (MWh)	Commercial Customers	Commercial Sales (MWh)	Municipal Sales (MWh)	Industrial Sales (MWh)	Base System Demand (MW)
2020	9.25	708,662.44	546,408.25	58.97	159,539.39	772,566.87	20,869.28	463,072.98	363.07
2021	9.21	715,579.53	548,792.12	58.92	159,887.04	773,412.69	20,603.83	463,072.98	364.96
2022	9.16	722,865.84	551,422.25	58.87	160,250.40	774,477.28	20,341.75	463,072.98	366.93
2023	9.11	729,773.81	553,741.28	58.81	160,592.28	775,222.20	20,083.00	463,072.98	368.80
2024	9.06	736,271.99	555,692.12	58.73	160,911.58	775,628.99	19,827.54	463,072.98	370.72
2025	9.01	742,864.21	557,678.51	58.65	161,233.31	776,061.67	19,575.33	463,072.98	372.64
2026	8.96	749,544.42	559,692.37	58.57	161,557.08	776,514.66	19,326.34	463,072.98	374.52
2027	8.91	756,213.65	561,665.35	58.49	161,878.06	776,919.30	19,080.51	463,072.98	376.35
2028	8.87	762,714.24	563,477.29	58.40	162,188.82	777,167.69	18,837.81	463,072.98	378.14
2029	8.82	769,064.58	565,142.38	58.30	162,490.44	777,276.20	18,598.19	463,072.98	379.91
2030	8.77	775,324.83	566,707.10	58.20	162,785.87	777,288.11	18,361.62	463,072.98	381.62
2031	8.73	781,471.34	568,157.83	58.08	163,074.15	777,189.89	18,128.06	463,072.98	383.22
2032	8.68	787,418.68	569,434.16	57.96	163,351.47	776,927.33	17,897.47	463,072.98	384.76
2033	8.63	793,122.87	570,506.03	57.83	163,615.86	776,474.83	17,669.81	463,072.98	386.27
2034	8.59	798,635.00	571,411.00	57.69	163,869.94	775,869.97	17,445.05	463,072.98	387.75
2035	8.54	803,979.30	572,171.69	57.54	164,115.05	775,132.17	17,223.15	463,072.98	389.27
2036	8.50	809,174.07	572,800.57	57.39	164,352.04	774,275.63	17,004.07	463,072.98	390.73
2037	8.45	814,237.37	573,314.91	57.23	164,581.94	773,315.07	16,787.78	463,072.98	392.11
2038	8.41	819,175.45	573,718.59	57.06	164,805.05	772,256.09	16,574.24	463,072.98	393.41
2039	8.36	824,038.98	574,049.37	56.89	165,023.77	771,133.00	16,363.42	463,072.98	394.68
2040	8.32	828,866.16	574,334.27	56.72	165,239.92	769,971.07	16,155.27	463,072.98	395.96

Schedule C-10. Black Hills Power: Historical and Forecasted Variable Values for Residential Use Per Customer Model

Black Hills Power **Confidential Appendix C**

Black Hills Power: Historical and Forecasted Variable Values for Residential Use Per Customer Model **Schedule C-10**

Year	Month	cdd60	hdd60	trend	m1	m2	m3	m4	m5	m6	m7	m8	m9	m10	m11	m12	ln(upc)
2007	1	-	992	9.08	1	-	-	-	-	-	-	-	-	-	-	-	6.99
2007	2	-	1,200	9.17	-	1	-	-	-	-	-	-	-	-	-	-	6.98
2007	3	1	623	9.25	-	-	1	-	-	-	-	-	-	-	-	-	6.79
2007	4	-	587	9.33	-	-	-	1	-	-	-	-	-	-	-	-	6.68
2007	5	38	163	9.42	-	-	-	-	1	-	-	-	-	-	-	-	6.49
2007	6	111	76	9.50	-	-	-	-	-	1	-	-	-	-	-	-	6.48
2007	7	434	-	9.58	-	-	-	-	-	-	1	-	-	-	-	-	6.76
2007	8	582	-	9.67	-	-	-	-	-	-	-	1	-	-	-	-	6.89
2007	9	234	42	9.75	-	-	-	-	-	-	-	-	1	-	-	-	6.58
2007	10	72	138	9.83	-	-	-	-	-	-	-	-	-	1	-	-	6.45
2007	11	3	402	9.92	-	-	-	-	-	-	-	-	-	-	1	-	6.56
2007	12	-	951	10.00	-	-	-	-	-	-	-	-	-	-	-	1	6.91
2008	1	-	949	10.08	1	-	-	-	-	-	-	-	-	-	-	-	6.97
2008	2	-	1,269	10.17	-	1	-	-	-	-	-	-	-	-	-	-	7.00
2008	3	-	776	10.25	-	-	1	-	-	-	-	-	-	-	-	-	6.83
2008	4	3	690	10.33	-	-	-	1	-	-	-	-	-	-	-	-	6.71
2008	5	-	403	10.42	-	-	-	-	1	-	-	-	-	-	-	-	6.54
2008	6	28	137	10.50	-	-	-	-	-	1	-	-	-	-	-	-	6.43
2008	7	264	1	10.58	-	-	-	-	-	-	1	-	-	-	-	-	6.62
2008	8	407	0	10.67	-	-	-	-	-	-	-	1	-	-	-	-	6.75
2008	9	207	57	10.75	-	-	-	-	-	-	-	-	1	-	-	-	6.56
2008	10	91	175	10.83	-	-	-	-	-	-	-	-	-	1	-	-	6.47
2008	11	4	488	10.92	-	-	-	-	-	-	-	-	-	-	1	-	6.59
2008	12	-	869	11.00	-	-	-	-	-	-	-	-	-	-	-	1	6.88
2009	1	-	1,216	11.08	1	-	-	-	-	-	-	-	-	-	-	-	7.05
2009	2	-	876	11.17	-	1	-	-	-	-	-	-	-	-	-	-	6.86
2009	3	-	888	11.25	-	-	1	-	-	-	-	-	-	-	-	-	6.87
2009	4	3	683	11.33	-	-	-	1	-	-	-	-	-	-	-	-	6.70
2009	5	7	346	11.42	-	-	-	-	1	-	-	-	-	-	-	-	6.52
2009	6	64	147	11.50	-	-	-	-	-	1	-	-	-	-	-	-	6.46
2009	7	269	-	11.58	-	-	-	-	-	-	1	-	-	-	-	-	6.62

2009	8	287	0	11.67	-	-	-	-	-	-	-	1	-	-	-	-	6.66
2009	9	216	5	11.75	-	-	-	-	-	-	-	-	1	-	-	-	6.54
2009	10	44	396	11.83	-	-	-	-	-	-	-	-	-	1	-	-	6.50
2009	11	2	499	11.92	-	-	-	-	-	-	-	-	-	-	1	-	6.59
2009	12	-	971	12.00	-	-	-	-	-	-	-	-	-	-	-	1	6.91
2010	1	-	1,133	12.08	1	-	-	-	-	-	-	-	-	-	-	-	7.02
2010	2	-	1,151	12.17	-	1	-	-	-	-	-	-	-	-	-	-	6.95
2010	3	-	832	12.25	-	-	1	-	-	-	-	-	-	-	-	-	6.84
2010	4	-	472	12.33	-	-	-	1	-	-	-	-	-	-	-	-	6.63
2010	5	-	412	12.42	-	-	-	-	1	-	-	-	-	-	-	-	6.53
2010	6	53	69	12.50	-	-	-	-	-	1	-	-	-	-	-	-	6.42
2010	7	267	0	12.58	-	-	-	-	-	-	1	-	-	-	-	-	6.62
2010	8	410	-	12.67	-	-	-	-	-	-	-	1	-	-	-	-	6.75
2010	9	261	3	12.75	-	-	-	-	-	-	-	-	1	-	-	-	6.57
2010	10	66	80	12.83	-	-	-	-	-	-	-	-	-	1	-	-	6.41
2010	11	3	384	12.92	-	-	-	-	-	-	-	-	-	-	1	-	6.54
2010	12	-	1,016	13.00	-	-	-	-	-	-	-	-	-	-	-	1	6.92
2011	1	-	1,196	13.08	1	-	-	-	-	-	-	-	-	-	-	-	7.04
2011	2	-	1,072	13.17	-	1	-	-	-	-	-	-	-	-	-	-	6.91
2011	3	-	1,027	13.25	-	-	1	-	-	-	-	-	-	-	-	-	6.90
2011	4	-	561	13.33	-	-	-	1	-	-	-	-	-	-	-	-	6.65
2011	5	0	419	13.42	-	-	-	-	1	-	-	-	-	-	-	-	6.53
2011	6	53	156	13.50	-	-	-	-	-	1	-	-	-	-	-	-	6.44
2011	7	256	1	13.58	-	-	-	-	-	-	1	-	-	-	-	-	6.60
2011	8	470	-	13.67	-	-	-	-	-	-	-	1	-	-	-	-	6.78
2011	9	308	32	13.75	-	-	-	-	-	-	-	-	1	-	-	-	6.61
2011	10	109	123	13.83	-	-	-	-	-	-	-	-	-	1	-	-	6.45
2011	11	-	533	13.92	-	-	-	-	-	-	-	-	-	-	1	-	6.59
2011	12	-	913	14.00	-	-	-	-	-	-	-	-	-	-	-	1	6.88
2012	1	-	746	14.08	1	-	-	-	-	-	-	-	-	-	-	-	6.88
2012	2	-	1,025	14.17	-	1	-	-	-	-	-	-	-	-	-	-	6.89
2012	3	-	674	14.25	-	-	1	-	-	-	-	-	-	-	-	-	6.78
2012	4	16	263	14.33	-	-	-	1	-	-	-	-	-	-	-	-	6.56
2012	5	36	179	14.42	-	-	-	-	1	-	-	-	-	-	-	-	6.47
2012	6	168	80	14.50	-	-	-	-	-	1	-	-	-	-	-	-	6.50

2012	7	467	-	14.58	-	-	-	-	-	-	1	-	-	-	-	-	6.76
2012	8	500	-	14.67	-	-	-	-	-	-	-	1	-	-	-	-	6.80
2012	9	350	1	14.75	-	-	-	-	-	-	-	-	1	-	-	-	6.63
2012	10	34	184	14.83	-	-	-	-	-	-	-	-	-	1	-	-	6.41
2012	11	2	559	14.92	-	-	-	-	-	-	-	-	-	-	1	-	6.59
2012	12	-	678	15.00	-	-	-	-	-	-	-	-	-	-	-	1	6.79
2013	1	-	1,127	15.08	1	-	-	-	-	-	-	-	-	-	-	-	7.00
2013	2	-	912	15.17	-	1	-	-	-	-	-	-	-	-	-	-	6.85
2013	3	-	740	15.25	-	-	1	-	-	-	-	-	-	-	-	-	6.80
2013	4	-	807	15.33	-	-	-	1	-	-	-	-	-	-	-	-	6.72
2013	5	27	409	15.42	-	-	-	-	1	-	-	-	-	-	-	-	6.53
2013	6	74	86	15.50	-	-	-	-	-	1	-	-	-	-	-	-	6.42
2013	7	354	-	15.58	-	-	-	-	-	-	1	-	-	-	-	-	6.67
2013	8	320	-	15.67	-	-	-	-	-	-	-	1	-	-	-	-	6.66
2013	9	448	-	15.75	-	-	-	-	-	-	-	-	1	-	-	-	6.69
2013	10	52	239	15.83	-	-	-	-	-	-	-	-	-	1	-	-	6.43
2013	11	-	603	15.92	-	-	-	-	-	-	-	-	-	-	1	-	6.60
2013	12	-	1,053	16.00	-	-	-	-	-	-	-	-	-	-	-	1	6.91
2014	1	-	1,047	16.08	1	-	-	-	-	-	-	-	-	-	-	-	6.97
2014	2	-	1,187	16.17	-	1	-	-	-	-	-	-	-	-	-	-	6.94
2014	3	-	900	16.25	-	-	1	-	-	-	-	-	-	-	-	-	6.84
2014	4	-	720	16.33	-	-	-	1	-	-	-	-	-	-	-	-	6.69
2014	5	-	374	16.42	-	-	-	-	1	-	-	-	-	-	-	-	6.49
2014	6	72	65	16.50	-	-	-	-	-	1	-	-	-	-	-	-	6.41
2014	7	232	-	16.58	-	-	-	-	-	-	1	-	-	-	-	-	6.57
2014	8	373	-	16.67	-	-	-	-	-	-	-	1	-	-	-	-	6.70
2014	9	169	100	16.75	-	-	-	-	-	-	-	-	1	-	-	-	6.51
2014	10	100	124	16.83	-	-	-	-	-	-	-	-	-	1	-	-	6.43
2014	11	5	545	16.92	-	-	-	-	-	-	-	-	-	-	1	-	6.58
2014	12	-	803	17.00	-	-	-	-	-	-	-	-	-	-	-	1	6.82
2015	1	-	1,170	17.08	1	-	-	-	-	-	-	-	-	-	-	-	7.01
2015	2	-	668	17.17	-	1	-	-	-	-	-	-	-	-	-	-	6.76
2015	3	8	786	17.25	-	-	1	-	-	-	-	-	-	-	-	-	6.81
2015	4	-	400	17.33	-	-	-	1	-	-	-	-	-	-	-	-	6.57
2015	5	5	326	17.42	-	-	-	-	1	-	-	-	-	-	-	-	6.48

2015	6	84	128	17.50	-	-	-	-	-	1	-	-	-	-	-	-	6.43
2015	7	296	-	17.58	-	-	-	-	-	-	1	-	-	-	-	-	6.61
2015	8	406	-	17.67	-	-	-	-	-	-	-	1	-	-	-	-	6.72
2015	9	277	8	17.75	-	-	-	-	-	-	-	-	1	-	-	-	6.56
2015	10	84	76	17.83	-	-	-	-	-	-	-	-	-	1	-	-	6.39
2015	11	4	402	17.92	-	-	-	-	-	-	-	-	-	-	1	-	6.52
2015	12	-	814	18.00	-	-	-	-	-	-	-	-	-	-	-	1	6.82
2016	1	-	1,128	18.08	1	-	-	-	-	-	-	-	-	-	-	-	6.99
2016	2	-	848	18.17	-	1	-	-	-	-	-	-	-	-	-	-	6.81
2016	3	-	456	18.25	-	-	1	-	-	-	-	-	-	-	-	-	6.68
2016	4	2	495	18.33	-	-	-	1	-	-	-	-	-	-	-	-	6.60
2016	5	15	368	18.42	-	-	-	-	1	-	-	-	-	-	-	-	6.49
2016	6	176	33	18.50	-	-	-	-	-	1	-	-	-	-	-	-	6.46
2016	7	386	-	18.58	-	-	-	-	-	-	1	-	-	-	-	-	6.67
2016	8	448	-	18.67	-	-	-	-	-	-	-	1	-	-	-	-	6.74
2016	9	201	23	18.75	-	-	-	-	-	-	-	-	1	-	-	-	6.50
2016	10	51	130	18.83	-	-	-	-	-	-	-	-	-	1	-	-	6.38
2016	11	11	208	18.92	-	-	-	-	-	-	-	-	-	-	1	-	6.46
2016	12	-	1,012	19.00	-	-	-	-	-	-	-	-	-	-	-	1	6.88
2017	1	-	1,317	19.08	1	-	-	-	-	-	-	-	-	-	-	-	7.05
2017	2	-	928	19.17	-	1	-	-	-	-	-	-	-	-	-	-	6.83
2017	3	-	665	19.25	-	-	1	-	-	-	-	-	-	-	-	-	6.75
2017	4	0	390	19.33	-	-	-	1	-	-	-	-	-	-	-	-	6.56
2017	5	34	289	19.42	-	-	-	-	1	-	-	-	-	-	-	-	6.47
2017	6	152	107	19.50	-	-	-	-	-	1	-	-	-	-	-	-	6.47
2017	7	357	0	19.58	-	-	-	-	-	-	1	-	-	-	-	-	6.65
2017	8	374	-	19.67	-	-	-	-	-	-	-	1	-	-	-	-	6.68
2017	9	342	11	19.75	-	-	-	-	-	-	-	-	1	-	-	-	6.60
2017	10	9	263	19.83	-	-	-	-	-	-	-	-	-	1	-	-	6.39
2017	11	11	546	19.92	-	-	-	-	-	-	-	-	-	-	1	-	6.57
2017	12	2	552	20.00	-	-	-	-	-	-	-	-	-	-	-	1	6.72
2018	1	-	1,294	20.08	1	-	-	-	-	-	-	-	-	-	-	-	7.03
2018	2	-	1,120	20.17	-	1	-	-	-	-	-	-	-	-	-	-	6.89
2018	3	-	986	20.25	-	-	1	-	-	-	-	-	-	-	-	-	6.85
2018	4	-	836	20.33	-	-	-	1	-	-	-	-	-	-	-	-	6.71

2018	5	24	259	20.42	-	-	-	-	1	-	-	-	-	-	-	-	6.45
2018	6	242	29	20.50	-	-	-	-	-	1	-	-	-	-	-	-	6.50
2018	7	281	12	20.58	-	-	-	-	-	-	1	-	-	-	-	-	6.59
2018	8	330	-	20.67	-	-	-	-	-	-	-	1	-	-	-	-	6.64
2018	9	228	6	20.75	-	-	-	-	-	-	-	-	1	-	-	-	6.50
2018	10	18	408	20.83	-	-	-	-	-	-	-	-	-	1	-	-	6.44
2018	11	-	553	20.92	-	-	-	-	-	-	-	-	-	-	1	-	6.55
2018	12	-	822	21.00	-	-	-	-	-	-	-	-	-	-	-	1	6.81
2019	1	-	892	21.08	1	-	-	-	-	-	-	-	-	-	-	-	6.89
2019	2	-	1,302	21.17	-	1	-	-	-	-	-	-	-	-	-	-	6.95
2019	3	-	1,303	21.25	-	-	1	-	-	-	-	-	-	-	-	-	6.95
2019	4	-	621	21.33	-	-	-	1	-	-	-	-	-	-	-	-	6.63
2019	5	11	382	21.42	-	-	-	-	1	-	-	-	-	-	-	-	6.48
2019	6	70	205	21.50	-	-	-	-	-	1	-	-	-	-	-	-	6.43
2019	7	217	2	21.58	-	-	-	-	-	-	1	-	-	-	-	-	6.53
2019	8	318	-	21.67	-	-	-	-	-	-	-	1	-	-	-	-	6.63
2019	9	196	14	21.75	-	-	-	-	-	-	-	-	1	-	-	-	6.48
2019	10	50	308	21.83	-	-	-	-	-	-	-	-	-	1	-	-	6.42
2019	11	-	749	21.92	-	-	-	-	-	-	-	-	-	-	1	-	6.61
2019	12	-	829	22.00	-	-	-	-	-	-	-	-	-	-	-	1	6.80
2020	1	-	1,039	22.08	1	-	-	-	-	-	-	-	-	-	-	-	6.94
2020	2	-	1,013	22.17	-	1	-	-	-	-	-	-	-	-	-	-	6.85
2020	3	0	810	22.25	-	-	1	-	-	-	-	-	-	-	-	-	6.78
2020	4	3	575	22.33	-	-	-	1	-	-	-	-	-	-	-	-	6.61
2020	5	15	334	22.42	-	-	-	-	1	-	-	-	-	-	-	-	6.46
2020	6	98	94	22.50	-	-	-	-	-	1	-	-	-	-	-	-	6.41
2020	7	321	4	22.58	-	-	-	-	-	-	1	-	-	-	-	-	6.60
2020	8	418	1	22.67	-	-	-	-	-	-	-	1	-	-	-	-	6.70
2020	9	270	22	22.75	-	-	-	-	-	-	-	-	1	-	-	-	6.53
2020	10	53	211	22.83	-	-	-	-	-	-	-	-	-	1	-	-	6.39
2020	11	5	502	22.92	-	-	-	-	-	-	-	-	-	-	1	-	6.53
2020	12	0	848	23.00	-	-	-	-	-	-	-	-	-	-	-	1	6.81
2021	1	-	1,039	23.08	1	-	-	-	-	-	-	-	-	-	-	-	6.93
2021	2	-	1,013	23.17	-	1	-	-	-	-	-	-	-	-	-	-	6.84
2021	3	0	810	23.25	-	-	1	-	-	-	-	-	-	-	-	-	6.78

2021	4	3	575	23.33	-	-	-	1	-	-	-	-	-	-	-	-	6.60
2021	5	15	334	23.42	-	-	-	-	1	-	-	-	-	-	-	-	6.45
2021	6	98	94	23.50	-	-	-	-	-	1	-	-	-	-	-	-	6.40
2021	7	321	4	23.58	-	-	-	-	-	-	1	-	-	-	-	-	6.60
2021	8	418	1	23.67	-	-	-	-	-	-	-	1	-	-	-	-	6.69
2021	9	270	22	23.75	-	-	-	-	-	-	-	-	1	-	-	-	6.52
2021	10	53	211	23.83	-	-	-	-	-	-	-	-	-	1	-	-	6.38
2021	11	5	502	23.92	-	-	-	-	-	-	-	-	-	-	1	-	6.52
2021	12	0	848	24.00	-	-	-	-	-	-	-	-	-	-	-	1	6.80
2022	1	-	1,039	24.08	1	-	-	-	-	-	-	-	-	-	-	-	6.93
2022	2	-	1,013	24.17	-	1	-	-	-	-	-	-	-	-	-	-	6.84
2022	3	0	810	24.25	-	-	1	-	-	-	-	-	-	-	-	-	6.77
2022	4	3	575	24.33	-	-	-	1	-	-	-	-	-	-	-	-	6.60
2022	5	15	334	24.42	-	-	-	-	1	-	-	-	-	-	-	-	6.45
2022	6	98	94	24.50	-	-	-	-	-	1	-	-	-	-	-	-	6.39
2022	7	321	4	24.58	-	-	-	-	-	-	1	-	-	-	-	-	6.59
2022	8	418	1	24.67	-	-	-	-	-	-	-	1	-	-	-	-	6.69
2022	9	270	22	24.75	-	-	-	-	-	-	-	-	1	-	-	-	6.52
2022	10	53	211	24.83	-	-	-	-	-	-	-	-	-	1	-	-	6.38
2022	11	5	502	24.92	-	-	-	-	-	-	-	-	-	-	1	-	6.52
2022	12	0	848	25.00	-	-	-	-	-	-	-	-	-	-	-	1	6.79
2023	1	-	1,039	25.08	1	-	-	-	-	-	-	-	-	-	-	-	6.92
2023	2	-	1,013	25.17	-	1	-	-	-	-	-	-	-	-	-	-	6.83
2023	3	0	810	25.25	-	-	1	-	-	-	-	-	-	-	-	-	6.77
2023	4	3	575	25.33	-	-	-	1	-	-	-	-	-	-	-	-	6.59
2023	5	15	334	25.42	-	-	-	-	1	-	-	-	-	-	-	-	6.44
2023	6	98	94	25.50	-	-	-	-	-	1	-	-	-	-	-	-	6.39
2023	7	321	4	25.58	-	-	-	-	-	-	1	-	-	-	-	-	6.59
2023	8	418	1	25.67	-	-	-	-	-	-	-	1	-	-	-	-	6.68
2023	9	270	22	25.75	-	-	-	-	-	-	-	-	1	-	-	-	6.51
2023	10	53	211	25.83	-	-	-	-	-	-	-	-	-	1	-	-	6.37
2023	11	5	502	25.92	-	-	-	-	-	-	-	-	-	-	1	-	6.51
2023	12	0	848	26.00	-	-	-	-	-	-	-	-	-	-	-	1	6.79
2024	1	-	1,039	26.08	1	-	-	-	-	-	-	-	-	-	-	-	6.91
2024	2	-	1,013	26.17	-	1	-	-	-	-	-	-	-	-	-	-	6.82

2024	3	0	810	26.25	-	-	1	-	-	-	-	-	-	-	-	-	6.76
2024	4	3	575	26.33	-	-	-	1	-	-	-	-	-	-	-	-	6.59
2024	5	15	334	26.42	-	-	-	-	1	-	-	-	-	-	-	-	6.44
2024	6	98	94	26.50	-	-	-	-	-	1	-	-	-	-	-	-	6.38
2024	7	321	4	26.58	-	-	-	-	-	-	1	-	-	-	-	-	6.58
2024	8	418	1	26.67	-	-	-	-	-	-	-	1	-	-	-	-	6.68
2024	9	270	22	26.75	-	-	-	-	-	-	-	-	1	-	-	-	6.51
2024	10	53	211	26.83	-	-	-	-	-	-	-	-	-	1	-	-	6.37
2024	11	5	502	26.92	-	-	-	-	-	-	-	-	-	-	1	-	6.51
2024	12	0	848	27.00	-	-	-	-	-	-	-	-	-	-	-	1	6.78
2025	1	-	1,039	27.08	1	-	-	-	-	-	-	-	-	-	-	-	6.91
2025	2	-	1,013	27.17	-	1	-	-	-	-	-	-	-	-	-	-	6.82
2025	3	0	810	27.25	-	-	1	-	-	-	-	-	-	-	-	-	6.76
2025	4	3	575	27.33	-	-	-	1	-	-	-	-	-	-	-	-	6.58
2025	5	15	334	27.42	-	-	-	-	1	-	-	-	-	-	-	-	6.43
2025	6	98	94	27.50	-	-	-	-	-	1	-	-	-	-	-	-	6.38
2025	7	321	4	27.58	-	-	-	-	-	-	1	-	-	-	-	-	6.58
2025	8	418	1	27.67	-	-	-	-	-	-	-	1	-	-	-	-	6.67
2025	9	270	22	27.75	-	-	-	-	-	-	-	-	1	-	-	-	6.50
2025	10	53	211	27.83	-	-	-	-	-	-	-	-	-	1	-	-	6.36
2025	11	5	502	27.92	-	-	-	-	-	-	-	-	-	-	1	-	6.50
2025	12	0	848	28.00	-	-	-	-	-	-	-	-	-	-	-	1	6.78
2026	1	-	1,039	28.08	1	-	-	-	-	-	-	-	-	-	-	-	6.90
2026	2	-	1,013	28.17	-	1	-	-	-	-	-	-	-	-	-	-	6.81
2026	3	0	810	28.25	-	-	1	-	-	-	-	-	-	-	-	-	6.75
2026	4	3	575	28.33	-	-	-	1	-	-	-	-	-	-	-	-	6.58
2026	5	15	334	28.42	-	-	-	-	1	-	-	-	-	-	-	-	6.43
2026	6	98	94	28.50	-	-	-	-	-	1	-	-	-	-	-	-	6.37
2026	7	321	4	28.58	-	-	-	-	-	-	1	-	-	-	-	-	6.57
2026	8	418	1	28.67	-	-	-	-	-	-	-	1	-	-	-	-	6.67
2026	9	270	22	28.75	-	-	-	-	-	-	-	-	1	-	-	-	6.50
2026	10	53	211	28.83	-	-	-	-	-	-	-	-	-	1	-	-	6.36
2026	11	5	502	28.92	-	-	-	-	-	-	-	-	-	-	1	-	6.50
2026	12	0	848	29.00	-	-	-	-	-	-	-	-	-	-	-	1	6.77
2027	1	-	1,039	29.08	1	-	-	-	-	-	-	-	-	-	-	-	6.90

2027	2	-	1,013	29.17	-	1	-	-	-	-	-	-	-	-	-	-	6.81
2027	3	0	810	29.25	-	-	1	-	-	-	-	-	-	-	-	-	6.74
2027	4	3	575	29.33	-	-	-	1	-	-	-	-	-	-	-	-	6.57
2027	5	15	334	29.42	-	-	-	-	1	-	-	-	-	-	-	-	6.42
2027	6	98	94	29.50	-	-	-	-	-	1	-	-	-	-	-	-	6.37
2027	7	321	4	29.58	-	-	-	-	-	-	1	-	-	-	-	-	6.57
2027	8	418	1	29.67	-	-	-	-	-	-	-	1	-	-	-	-	6.66
2027	9	270	22	29.75	-	-	-	-	-	-	-	-	1	-	-	-	6.49
2027	10	53	211	29.83	-	-	-	-	-	-	-	-	-	1	-	-	6.35
2027	11	5	502	29.92	-	-	-	-	-	-	-	-	-	-	1	-	6.49
2027	12	0	848	30.00	-	-	-	-	-	-	-	-	-	-	-	1	6.77
2028	1	-	1,039	30.08	1	-	-	-	-	-	-	-	-	-	-	-	6.89
2028	2	-	1,013	30.17	-	1	-	-	-	-	-	-	-	-	-	-	6.80
2028	3	0	810	30.25	-	-	1	-	-	-	-	-	-	-	-	-	6.74
2028	4	3	575	30.33	-	-	-	1	-	-	-	-	-	-	-	-	6.57
2028	5	15	334	30.42	-	-	-	-	1	-	-	-	-	-	-	-	6.42
2028	6	98	94	30.50	-	-	-	-	-	1	-	-	-	-	-	-	6.36
2028	7	321	4	30.58	-	-	-	-	-	-	1	-	-	-	-	-	6.56
2028	8	418	1	30.67	-	-	-	-	-	-	-	1	-	-	-	-	6.66
2028	9	270	22	30.75	-	-	-	-	-	-	-	-	1	-	-	-	6.49
2028	10	53	211	30.83	-	-	-	-	-	-	-	-	-	1	-	-	6.35
2028	11	5	502	30.92	-	-	-	-	-	-	-	-	-	-	1	-	6.49
2028	12	0	848	31.00	-	-	-	-	-	-	-	-	-	-	-	1	6.76
2029	1	-	1,039	31.08	1	-	-	-	-	-	-	-	-	-	-	-	6.89
2029	2	-	1,013	31.17	-	1	-	-	-	-	-	-	-	-	-	-	6.80
2029	3	0	810	31.25	-	-	1	-	-	-	-	-	-	-	-	-	6.73
2029	4	3	575	31.33	-	-	-	1	-	-	-	-	-	-	-	-	6.56
2029	5	15	334	31.42	-	-	-	-	1	-	-	-	-	-	-	-	6.41
2029	6	98	94	31.50	-	-	-	-	-	1	-	-	-	-	-	-	6.36
2029	7	321	4	31.58	-	-	-	-	-	-	1	-	-	-	-	-	6.56
2029	8	418	1	31.67	-	-	-	-	-	-	-	1	-	-	-	-	6.65
2029	9	270	22	31.75	-	-	-	-	-	-	-	-	1	-	-	-	6.48
2029	10	53	211	31.83	-	-	-	-	-	-	-	-	-	1	-	-	6.34
2029	11	5	502	31.92	-	-	-	-	-	-	-	-	-	-	1	-	6.48
2029	12	0	848	32.00	-	-	-	-	-	-	-	-	-	-	-	1	6.76

2030	1	-	1,039	32.08	1	-	-	-	-	-	-	-	-	-	-	-	6.88
2030	2	-	1,013	32.17	-	1	-	-	-	-	-	-	-	-	-	-	6.79
2030	3	0	810	32.25	-	-	1	-	-	-	-	-	-	-	-	-	6.73
2030	4	3	575	32.33	-	-	-	1	-	-	-	-	-	-	-	-	6.56
2030	5	15	334	32.42	-	-	-	-	1	-	-	-	-	-	-	-	6.41
2030	6	98	94	32.50	-	-	-	-	-	1	-	-	-	-	-	-	6.35
2030	7	321	4	32.58	-	-	-	-	-	-	1	-	-	-	-	-	6.55
2030	8	418	1	32.67	-	-	-	-	-	-	-	1	-	-	-	-	6.65
2030	9	270	22	32.75	-	-	-	-	-	-	-	-	1	-	-	-	6.48
2030	10	53	211	32.83	-	-	-	-	-	-	-	-	-	1	-	-	6.34
2030	11	5	502	32.92	-	-	-	-	-	-	-	-	-	-	1	-	6.48
2030	12	0	848	33.00	-	-	-	-	-	-	-	-	-	-	-	1	6.75
2031	1	-	1,039	33.08	1	-	-	-	-	-	-	-	-	-	-	-	6.88
2031	2	-	1,013	33.17	-	1	-	-	-	-	-	-	-	-	-	-	6.79
2031	3	0	810	33.25	-	-	1	-	-	-	-	-	-	-	-	-	6.72
2031	4	3	575	33.33	-	-	-	1	-	-	-	-	-	-	-	-	6.55
2031	5	15	334	33.42	-	-	-	-	1	-	-	-	-	-	-	-	6.40
2031	6	98	94	33.50	-	-	-	-	-	1	-	-	-	-	-	-	6.35
2031	7	321	4	33.58	-	-	-	-	-	-	1	-	-	-	-	-	6.55
2031	8	418	1	33.67	-	-	-	-	-	-	-	1	-	-	-	-	6.64
2031	9	270	22	33.75	-	-	-	-	-	-	-	-	1	-	-	-	6.47
2031	10	53	211	33.83	-	-	-	-	-	-	-	-	-	1	-	-	6.33
2031	11	5	502	33.92	-	-	-	-	-	-	-	-	-	-	1	-	6.47
2031	12	0	848	34.00	-	-	-	-	-	-	-	-	-	-	-	1	6.75
2032	1	-	1,039	34.08	1	-	-	-	-	-	-	-	-	-	-	-	6.87
2032	2	-	1,013	34.17	-	1	-	-	-	-	-	-	-	-	-	-	6.78
2032	3	0	810	34.25	-	-	1	-	-	-	-	-	-	-	-	-	6.72
2032	4	3	575	34.33	-	-	-	1	-	-	-	-	-	-	-	-	6.54
2032	5	15	334	34.42	-	-	-	-	1	-	-	-	-	-	-	-	6.40
2032	6	98	94	34.50	-	-	-	-	-	1	-	-	-	-	-	-	6.34
2032	7	321	4	34.58	-	-	-	-	-	-	1	-	-	-	-	-	6.54
2032	8	418	1	34.67	-	-	-	-	-	-	-	1	-	-	-	-	6.63
2032	9	270	22	34.75	-	-	-	-	-	-	-	-	1	-	-	-	6.47
2032	10	53	211	34.83	-	-	-	-	-	-	-	-	-	1	-	-	6.32
2032	11	5	502	34.92	-	-	-	-	-	-	-	-	-	-	1	-	6.47

2032	12	0	848	35.00	-	-	-	-	-	-	-	-	-	-	-	1	6.74
2033	1	-	1,039	35.08	1	-	-	-	-	-	-	-	-	-	-	-	6.87
2033	2	-	1,013	35.17	-	1	-	-	-	-	-	-	-	-	-	-	6.78
2033	3	0	810	35.25	-	-	1	-	-	-	-	-	-	-	-	-	6.71
2033	4	3	575	35.33	-	-	-	1	-	-	-	-	-	-	-	-	6.54
2033	5	15	334	35.42	-	-	-	-	1	-	-	-	-	-	-	-	6.39
2033	6	98	94	35.50	-	-	-	-	-	1	-	-	-	-	-	-	6.34
2033	7	321	4	35.58	-	-	-	-	-	-	1	-	-	-	-	-	6.54
2033	8	418	1	35.67	-	-	-	-	-	-	-	1	-	-	-	-	6.63
2033	9	270	22	35.75	-	-	-	-	-	-	-	-	1	-	-	-	6.46
2033	10	53	211	35.83	-	-	-	-	-	-	-	-	-	1	-	-	6.32
2033	11	5	502	35.92	-	-	-	-	-	-	-	-	-	-	1	-	6.46
2033	12	0	848	36.00	-	-	-	-	-	-	-	-	-	-	-	1	6.74
2034	1	-	1,039	36.08	1	-	-	-	-	-	-	-	-	-	-	-	6.86
2034	2	-	1,013	36.17	-	1	-	-	-	-	-	-	-	-	-	-	6.77
2034	3	0	810	36.25	-	-	1	-	-	-	-	-	-	-	-	-	6.71
2034	4	3	575	36.33	-	-	-	1	-	-	-	-	-	-	-	-	6.53
2034	5	15	334	36.42	-	-	-	-	1	-	-	-	-	-	-	-	6.38
2034	6	98	94	36.50	-	-	-	-	-	1	-	-	-	-	-	-	6.33
2034	7	321	4	36.58	-	-	-	-	-	-	1	-	-	-	-	-	6.53
2034	8	418	1	36.67	-	-	-	-	-	-	-	1	-	-	-	-	6.62
2034	9	270	22	36.75	-	-	-	-	-	-	-	-	1	-	-	-	6.45
2034	10	53	211	36.83	-	-	-	-	-	-	-	-	-	1	-	-	6.31
2034	11	5	502	36.92	-	-	-	-	-	-	-	-	-	-	1	-	6.46
2034	12	0	848	37.00	-	-	-	-	-	-	-	-	-	-	-	1	6.73
2035	1	-	1,039	37.08	1	-	-	-	-	-	-	-	-	-	-	-	6.86
2035	2	-	1,013	37.17	-	1	-	-	-	-	-	-	-	-	-	-	6.77
2035	3	0	810	37.25	-	-	1	-	-	-	-	-	-	-	-	-	6.70
2035	4	3	575	37.33	-	-	-	1	-	-	-	-	-	-	-	-	6.53
2035	5	15	334	37.42	-	-	-	-	1	-	-	-	-	-	-	-	6.38
2035	6	98	94	37.50	-	-	-	-	-	1	-	-	-	-	-	-	6.33
2035	7	321	4	37.58	-	-	-	-	-	-	1	-	-	-	-	-	6.52
2035	8	418	1	37.67	-	-	-	-	-	-	-	1	-	-	-	-	6.62
2035	9	270	22	37.75	-	-	-	-	-	-	-	-	1	-	-	-	6.45
2035	10	53	211	37.83	-	-	-	-	-	-	-	-	-	1	-	-	6.31

2035	11	5	502	37.92	-	-	-	-	-	-	-	-	-	-	1	-	6.45
2035	12	0	848	38.00	-	-	-	-	-	-	-	-	-	-	-	1	6.72
2036	1	-	1,039	38.08	1	-	-	-	-	-	-	-	-	-	-	-	6.85
2036	2	-	1,013	38.17	-	1	-	-	-	-	-	-	-	-	-	-	6.76
2036	3	0	810	38.25	-	-	1	-	-	-	-	-	-	-	-	-	6.70
2036	4	3	575	38.33	-	-	-	1	-	-	-	-	-	-	-	-	6.52
2036	5	15	334	38.42	-	-	-	-	1	-	-	-	-	-	-	-	6.37
2036	6	98	94	38.50	-	-	-	-	-	1	-	-	-	-	-	-	6.32
2036	7	321	4	38.58	-	-	-	-	-	-	1	-	-	-	-	-	6.52
2036	8	418	1	38.67	-	-	-	-	-	-	-	1	-	-	-	-	6.61
2036	9	270	22	38.75	-	-	-	-	-	-	-	-	1	-	-	-	6.44
2036	10	53	211	38.83	-	-	-	-	-	-	-	-	-	1	-	-	6.30
2036	11	5	502	38.92	-	-	-	-	-	-	-	-	-	-	1	-	6.44
2036	12	0	848	39.00	-	-	-	-	-	-	-	-	-	-	-	1	6.72
2037	1	-	1,039	39.08	1	-	-	-	-	-	-	-	-	-	-	-	6.85
2037	2	-	1,013	39.17	-	1	-	-	-	-	-	-	-	-	-	-	6.76
2037	3	0	810	39.25	-	-	1	-	-	-	-	-	-	-	-	-	6.69
2037	4	3	575	39.33	-	-	-	1	-	-	-	-	-	-	-	-	6.52
2037	5	15	334	39.42	-	-	-	-	1	-	-	-	-	-	-	-	6.37
2037	6	98	94	39.50	-	-	-	-	-	1	-	-	-	-	-	-	6.31
2037	7	321	4	39.58	-	-	-	-	-	-	1	-	-	-	-	-	6.51
2037	8	418	1	39.67	-	-	-	-	-	-	-	1	-	-	-	-	6.61
2037	9	270	22	39.75	-	-	-	-	-	-	-	-	1	-	-	-	6.44
2037	10	53	211	39.83	-	-	-	-	-	-	-	-	-	1	-	-	6.30
2037	11	5	502	39.92	-	-	-	-	-	-	-	-	-	-	1	-	6.44
2037	12	0	848	40.00	-	-	-	-	-	-	-	-	-	-	-	1	6.71
2038	1	-	1,039	40.08	1	-	-	-	-	-	-	-	-	-	-	-	6.84
2038	2	-	1,013	40.17	-	1	-	-	-	-	-	-	-	-	-	-	6.75
2038	3	0	810	40.25	-	-	1	-	-	-	-	-	-	-	-	-	6.69
2038	4	3	575	40.33	-	-	-	1	-	-	-	-	-	-	-	-	6.51
2038	5	15	334	40.42	-	-	-	-	1	-	-	-	-	-	-	-	6.36
2038	6	98	94	40.50	-	-	-	-	-	1	-	-	-	-	-	-	6.31
2038	7	321	4	40.58	-	-	-	-	-	-	1	-	-	-	-	-	6.51
2038	8	418	1	40.67	-	-	-	-	-	-	-	1	-	-	-	-	6.60
2038	9	270	22	40.75	-	-	-	-	-	-	-	-	1	-	-	-	6.43

2038	10	53	211	40.83	-	-	-	-	-	-	-	-	-	1	-	-	6.29
2038	11	5	502	40.92	-	-	-	-	-	-	-	-	-	-	1	-	6.43
2038	12	0	848	41.00	-	-	-	-	-	-	-	-	-	-	-	1	6.71
2039	1	-	1,039	41.08	1	-	-	-	-	-	-	-	-	-	-	-	6.83
2039	2	-	1,013	41.17	-	1	-	-	-	-	-	-	-	-	-	-	6.74
2039	3	0	810	41.25	-	-	1	-	-	-	-	-	-	-	-	-	6.68
2039	4	3	575	41.33	-	-	-	1	-	-	-	-	-	-	-	-	6.51
2039	5	15	334	41.42	-	-	-	-	1	-	-	-	-	-	-	-	6.36
2039	6	98	94	41.50	-	-	-	-	-	1	-	-	-	-	-	-	6.30
2039	7	321	4	41.58	-	-	-	-	-	-	1	-	-	-	-	-	6.50
2039	8	418	1	41.67	-	-	-	-	-	-	-	1	-	-	-	-	6.60
2039	9	270	22	41.75	-	-	-	-	-	-	-	-	1	-	-	-	6.43
2039	10	53	211	41.83	-	-	-	-	-	-	-	-	-	1	-	-	6.29
2039	11	5	502	41.92	-	-	-	-	-	-	-	-	-	-	1	-	6.43
2039	12	0	848	42.00	-	-	-	-	-	-	-	-	-	-	-	1	6.70
2040	1	-	1,039	42.08	1	-	-	-	-	-	-	-	-	-	-	-	6.83
2040	2	-	1,013	42.17	-	1	-	-	-	-	-	-	-	-	-	-	6.74
2040	3	0	810	42.25	-	-	1	-	-	-	-	-	-	-	-	-	6.68
2040	4	3	575	42.33	-	-	-	1	-	-	-	-	-	-	-	-	6.50
2040	5	15	334	42.42	-	-	-	-	1	-	-	-	-	-	-	-	6.35
2040	6	98	94	42.50	-	-	-	-	-	1	-	-	-	-	-	-	6.30
2040	7	321	4	42.58	-	-	-	-	-	-	1	-	-	-	-	-	6.50
2040	8	418	1	42.67	-	-	-	-	-	-	-	1	-	-	-	-	6.59
2040	9	270	22	42.75	-	-	-	-	-	-	-	-	1	-	-	-	6.42
2040	10	53	211	42.83	-	-	-	-	-	-	-	-	-	1	-	-	6.28
2040	11	5	502	42.92	-	-	-	-	-	-	-	-	-	-	1	-	6.42
2040	12	0	848	43.00	-	-	-	-	-	-	-	-	-	-	-	1	6.70

Schedule C-11. Black Hills Power: Variable Statistical Values for Residential Use Per Customer Model

Black Hills Power **Confidential Appendix C**

Black Hills Power: Variable Statistical Values for Residential Use Per Customer Model **Schedule C-11**

Variable	Coefficient	Standard Error	P Value	R2 = 0.9652
cdd60	0.001	0.000	0.000	
hdd60	0.000	0.000	0.000	
trend	-0.005	0.001	0.000	
m2	-0.081	0.015	0.000	
m3	-0.077	0.018	0.000	
m4	-0.172	0.021	0.000	
m5	-0.249	0.026	0.000	
m6	-0.284	0.032	0.000	
m7	-0.221	0.040	0.000	
m8	-0.198	0.044	0.000	
m9	-0.263	0.038	0.000	
m10	-0.305	0.029	0.000	
m11	-0.225	0.023	0.000	
m12	-0.062	0.016	0.000	
_cons	6.704	0.035	0.000	

Schedule C-12. Black Hills Power: Historical and Forecasted Variable Values for Residential Customer Model

Black Hills Power **Confidential Appendix C**

Black Hills Power: Historical and Forecasted Variable Values for Residential Customer Model **Schedule C-12**

Year	Month	lntotemp12	m1	m2	m3	m4	m5	m6	m7	m8	m9	m10	m11	m12	ln(custs)
2007	1	3.41	1	-	-	-	-	-	-	-	-	-	-	-	10.87
2007	2	3.41	-	1	-	-	-	-	-	-	-	-	-	-	10.87
2007	3	3.41	-	-	1	-	-	-	-	-	-	-	-	-	10.87
2007	4	3.42	-	-	-	1	-	-	-	-	-	-	-	-	10.87
2007	5	3.42	-	-	-	-	1	-	-	-	-	-	-	-	10.87
2007	6	3.42	-	-	-	-	-	1	-	-	-	-	-	-	10.88
2007	7	3.42	-	-	-	-	-	-	1	-	-	-	-	-	10.88
2007	8	3.42	-	-	-	-	-	-	-	1	-	-	-	-	10.88
2007	9	3.43	-	-	-	-	-	-	-	-	1	-	-	-	10.88
2007	10	3.43	-	-	-	-	-	-	-	-	-	1	-	-	10.88
2007	11	3.43	-	-	-	-	-	-	-	-	-	-	1	-	10.88
2007	12	3.43	-	-	-	-	-	-	-	-	-	-	-	1	10.89
2008	1	3.43	1	-	-	-	-	-	-	-	-	-	-	-	10.89
2008	2	3.44	-	1	-	-	-	-	-	-	-	-	-	-	10.89
2008	3	3.44	-	-	1	-	-	-	-	-	-	-	-	-	10.89
2008	4	3.44	-	-	-	1	-	-	-	-	-	-	-	-	10.89
2008	5	3.44	-	-	-	-	1	-	-	-	-	-	-	-	10.89
2008	6	3.44	-	-	-	-	-	1	-	-	-	-	-	-	10.89
2008	7	3.44	-	-	-	-	-	-	1	-	-	-	-	-	10.89
2008	8	3.44	-	-	-	-	-	-	-	1	-	-	-	-	10.90
2008	9	3.45	-	-	-	-	-	-	-	-	1	-	-	-	10.90
2008	10	3.45	-	-	-	-	-	-	-	-	-	1	-	-	10.90
2008	11	3.45	-	-	-	-	-	-	-	-	-	-	1	-	10.90
2008	12	3.45	-	-	-	-	-	-	-	-	-	-	-	1	10.90
2009	1	3.45	1	-	-	-	-	-	-	-	-	-	-	-	10.90
2009	2	3.45	-	1	-	-	-	-	-	-	-	-	-	-	10.90
2009	3	3.45	-	-	1	-	-	-	-	-	-	-	-	-	10.90
2009	4	3.45	-	-	-	1	-	-	-	-	-	-	-	-	10.90
2009	5	3.45	-	-	-	-	1	-	-	-	-	-	-	-	10.90
2009	6	3.45	-	-	-	-	-	1	-	-	-	-	-	-	10.90
2009	7	3.45	-	-	-	-	-	-	1	-	-	-	-	-	10.90

2009	8	3.45	-	-	-	-	-	-	-	1	-	-	-	-	10.90
2009	9	3.45	-	-	-	-	-	-	-	-	1	-	-	-	10.90
2009	10	3.45	-	-	-	-	-	-	-	-	-	1	-	-	10.90
2009	11	3.45	-	-	-	-	-	-	-	-	-	-	1	-	10.90
2009	12	3.45	-	-	-	-	-	-	-	-	-	-	-	1	10.90
2010	1	3.44	1	-	-	-	-	-	-	-	-	-	-	-	10.90
2010	2	3.44	-	1	-	-	-	-	-	-	-	-	-	-	10.90
2010	3	3.44	-	-	1	-	-	-	-	-	-	-	-	-	10.90
2010	4	3.44	-	-	-	1	-	-	-	-	-	-	-	-	10.90
2010	5	3.44	-	-	-	-	1	-	-	-	-	-	-	-	10.90
2010	6	3.44	-	-	-	-	-	1	-	-	-	-	-	-	10.90
2010	7	3.44	-	-	-	-	-	-	1	-	-	-	-	-	10.90
2010	8	3.44	-	-	-	-	-	-	-	1	-	-	-	-	10.90
2010	9	3.44	-	-	-	-	-	-	-	-	1	-	-	-	10.90
2010	10	3.44	-	-	-	-	-	-	-	-	-	1	-	-	10.90
2010	11	3.44	-	-	-	-	-	-	-	-	-	-	1	-	10.90
2010	12	3.44	-	-	-	-	-	-	-	-	-	-	-	1	10.90
2011	1	3.44	1	-	-	-	-	-	-	-	-	-	-	-	10.90
2011	2	3.45	-	1	-	-	-	-	-	-	-	-	-	-	10.90
2011	3	3.45	-	-	1	-	-	-	-	-	-	-	-	-	10.90
2011	4	3.45	-	-	-	1	-	-	-	-	-	-	-	-	10.90
2011	5	3.45	-	-	-	-	1	-	-	-	-	-	-	-	10.90
2011	6	3.45	-	-	-	-	-	1	-	-	-	-	-	-	10.90
2011	7	3.45	-	-	-	-	-	-	1	-	-	-	-	-	10.90
2011	8	3.45	-	-	-	-	-	-	-	1	-	-	-	-	10.90
2011	9	3.45	-	-	-	-	-	-	-	-	1	-	-	-	10.90
2011	10	3.45	-	-	-	-	-	-	-	-	-	1	-	-	10.90
2011	11	3.45	-	-	-	-	-	-	-	-	-	-	1	-	10.90
2011	12	3.45	-	-	-	-	-	-	-	-	-	-	-	1	10.91
2012	1	3.45	1	-	-	-	-	-	-	-	-	-	-	-	10.91
2012	2	3.46	-	1	-	-	-	-	-	-	-	-	-	-	10.91
2012	3	3.46	-	-	1	-	-	-	-	-	-	-	-	-	10.91
2012	4	3.46	-	-	-	1	-	-	-	-	-	-	-	-	10.91
2012	5	3.46	-	-	-	-	1	-	-	-	-	-	-	-	10.91
2012	6	3.46	-	-	-	-	-	1	-	-	-	-	-	-	10.91

2012	7	3.46	-	-	-	-	-	-	1	-	-	-	-	-	10.91
2012	8	3.46	-	-	-	-	-	-	-	1	-	-	-	-	10.91
2012	9	3.46	-	-	-	-	-	-	-	-	1	-	-	-	10.91
2012	10	3.46	-	-	-	-	-	-	-	-	-	1	-	-	10.91
2012	11	3.46	-	-	-	-	-	-	-	-	-	-	1	-	10.91
2012	12	3.46	-	-	-	-	-	-	-	-	-	-	-	1	10.91
2013	1	3.47	1	-	-	-	-	-	-	-	-	-	-	-	10.91
2013	2	3.47	-	1	-	-	-	-	-	-	-	-	-	-	10.92
2013	3	3.47	-	-	1	-	-	-	-	-	-	-	-	-	10.92
2013	4	3.47	-	-	-	1	-	-	-	-	-	-	-	-	10.92
2013	5	3.47	-	-	-	-	1	-	-	-	-	-	-	-	10.92
2013	6	3.47	-	-	-	-	-	1	-	-	-	-	-	-	10.92
2013	7	3.47	-	-	-	-	-	-	1	-	-	-	-	-	10.92
2013	8	3.47	-	-	-	-	-	-	-	1	-	-	-	-	10.92
2013	9	3.47	-	-	-	-	-	-	-	-	1	-	-	-	10.92
2013	10	3.47	-	-	-	-	-	-	-	-	-	1	-	-	10.92
2013	11	3.47	-	-	-	-	-	-	-	-	-	-	1	-	10.92
2013	12	3.48	-	-	-	-	-	-	-	-	-	-	-	1	10.92
2014	1	3.48	1	-	-	-	-	-	-	-	-	-	-	-	10.92
2014	2	3.48	-	1	-	-	-	-	-	-	-	-	-	-	10.93
2014	3	3.48	-	-	1	-	-	-	-	-	-	-	-	-	10.93
2014	4	3.48	-	-	-	1	-	-	-	-	-	-	-	-	10.93
2014	5	3.48	-	-	-	-	1	-	-	-	-	-	-	-	10.93
2014	6	3.48	-	-	-	-	-	1	-	-	-	-	-	-	10.93
2014	7	3.48	-	-	-	-	-	-	1	-	-	-	-	-	10.93
2014	8	3.48	-	-	-	-	-	-	-	1	-	-	-	-	10.93
2014	9	3.49	-	-	-	-	-	-	-	-	1	-	-	-	10.93
2014	10	3.49	-	-	-	-	-	-	-	-	-	1	-	-	10.93
2014	11	3.49	-	-	-	-	-	-	-	-	-	-	1	-	10.93
2014	12	3.49	-	-	-	-	-	-	-	-	-	-	-	1	10.94
2015	1	3.49	1	-	-	-	-	-	-	-	-	-	-	-	10.94
2015	2	3.49	-	1	-	-	-	-	-	-	-	-	-	-	10.94
2015	3	3.49	-	-	1	-	-	-	-	-	-	-	-	-	10.94
2015	4	3.49	-	-	-	1	-	-	-	-	-	-	-	-	10.94
2015	5	3.49	-	-	-	-	1	-	-	-	-	-	-	-	10.94

2015	6	3.49	-	-	-	-	-	1	-	-	-	-	-	-	10.94
2015	7	3.49	-	-	-	-	-	-	1	-	-	-	-	-	10.94
2015	8	3.49	-	-	-	-	-	-	-	1	-	-	-	-	10.94
2015	9	3.49	-	-	-	-	-	-	-	-	1	-	-	-	10.94
2015	10	3.49	-	-	-	-	-	-	-	-	-	1	-	-	10.94
2015	11	3.49	-	-	-	-	-	-	-	-	-	-	1	-	10.94
2015	12	3.49	-	-	-	-	-	-	-	-	-	-	-	1	10.94
2016	1	3.49	1	-	-	-	-	-	-	-	-	-	-	-	10.94
2016	2	3.49	-	1	-	-	-	-	-	-	-	-	-	-	10.94
2016	3	3.49	-	-	1	-	-	-	-	-	-	-	-	-	10.94
2016	4	3.49	-	-	-	1	-	-	-	-	-	-	-	-	10.94
2016	5	3.50	-	-	-	-	1	-	-	-	-	-	-	-	10.94
2016	6	3.50	-	-	-	-	-	1	-	-	-	-	-	-	10.94
2016	7	3.50	-	-	-	-	-	-	1	-	-	-	-	-	10.94
2016	8	3.50	-	-	-	-	-	-	-	1	-	-	-	-	10.94
2016	9	3.50	-	-	-	-	-	-	-	-	1	-	-	-	10.95
2016	10	3.50	-	-	-	-	-	-	-	-	-	1	-	-	10.95
2016	11	3.50	-	-	-	-	-	-	-	-	-	-	1	-	10.95
2016	12	3.50	-	-	-	-	-	-	-	-	-	-	-	1	10.95
2017	1	3.50	1	-	-	-	-	-	-	-	-	-	-	-	10.95
2017	2	3.50	-	1	-	-	-	-	-	-	-	-	-	-	10.95
2017	3	3.50	-	-	1	-	-	-	-	-	-	-	-	-	10.95
2017	4	3.51	-	-	-	1	-	-	-	-	-	-	-	-	10.95
2017	5	3.51	-	-	-	-	1	-	-	-	-	-	-	-	10.95
2017	6	3.51	-	-	-	-	-	1	-	-	-	-	-	-	10.95
2017	7	3.51	-	-	-	-	-	-	1	-	-	-	-	-	10.95
2017	8	3.51	-	-	-	-	-	-	-	1	-	-	-	-	10.95
2017	9	3.51	-	-	-	-	-	-	-	-	1	-	-	-	10.96
2017	10	3.51	-	-	-	-	-	-	-	-	-	1	-	-	10.96
2017	11	3.51	-	-	-	-	-	-	-	-	-	-	1	-	10.96
2017	12	3.51	-	-	-	-	-	-	-	-	-	-	-	1	10.96
2018	1	3.51	1	-	-	-	-	-	-	-	-	-	-	-	10.96
2018	2	3.52	-	1	-	-	-	-	-	-	-	-	-	-	10.96
2018	3	3.52	-	-	1	-	-	-	-	-	-	-	-	-	10.96
2018	4	3.52	-	-	-	1	-	-	-	-	-	-	-	-	10.96

2018	5	3.52	-	-	-	-	1	-	-	-	-	-	-	-	10.96
2018	6	3.52	-	-	-	-	-	1	-	-	-	-	-	-	10.96
2018	7	3.52	-	-	-	-	-	-	1	-	-	-	-	-	10.96
2018	8	3.52	-	-	-	-	-	-	-	1	-	-	-	-	10.97
2018	9	3.52	-	-	-	-	-	-	-	-	1	-	-	-	10.97
2018	10	3.52	-	-	-	-	-	-	-	-	-	1	-	-	10.97
2018	11	3.53	-	-	-	-	-	-	-	-	-	-	1	-	10.97
2018	12	3.53	-	-	-	-	-	-	-	-	-	-	-	1	10.97
2019	1	3.53	1	-	-	-	-	-	-	-	-	-	-	-	10.97
2019	2	3.53	-	1	-	-	-	-	-	-	-	-	-	-	10.97
2019	3	3.53	-	-	1	-	-	-	-	-	-	-	-	-	10.97
2019	4	3.53	-	-	-	1	-	-	-	-	-	-	-	-	10.97
2019	5	3.53	-	-	-	-	1	-	-	-	-	-	-	-	10.97
2019	6	3.53	-	-	-	-	-	1	-	-	-	-	-	-	10.98
2019	7	3.53	-	-	-	-	-	-	1	-	-	-	-	-	10.98
2019	8	3.54	-	-	-	-	-	-	-	1	-	-	-	-	10.98
2019	9	3.54	-	-	-	-	-	-	-	-	1	-	-	-	10.98
2019	10	3.54	-	-	-	-	-	-	-	-	-	1	-	-	10.98
2019	11	3.54	-	-	-	-	-	-	-	-	-	-	1	-	10.98
2019	12	3.54	-	-	-	-	-	-	-	-	-	-	-	1	10.98
2020	1	3.54	1	-	-	-	-	-	-	-	-	-	-	-	10.98
2020	2	3.54	-	1	-	-	-	-	-	-	-	-	-	-	10.98
2020	3	3.54	-	-	1	-	-	-	-	-	-	-	-	-	10.98
2020	4	3.54	-	-	-	1	-	-	-	-	-	-	-	-	10.98
2020	5	3.54	-	-	-	-	1	-	-	-	-	-	-	-	10.98
2020	6	3.55	-	-	-	-	-	1	-	-	-	-	-	-	10.99
2020	7	3.55	-	-	-	-	-	-	1	-	-	-	-	-	10.99
2020	8	3.55	-	-	-	-	-	-	-	1	-	-	-	-	10.99
2020	9	3.55	-	-	-	-	-	-	-	-	1	-	-	-	10.99
2020	10	3.55	-	-	-	-	-	-	-	-	-	1	-	-	10.99
2020	11	3.55	-	-	-	-	-	-	-	-	-	-	1	-	10.99
2020	12	3.55	-	-	-	-	-	-	-	-	-	-	-	1	10.99
2021	1	3.55	1	-	-	-	-	-	-	-	-	-	-	-	10.99
2021	2	3.55	-	1	-	-	-	-	-	-	-	-	-	-	10.99
2021	3	3.55	-	-	1	-	-	-	-	-	-	-	-	-	10.99

2021	4	3.55	-	-	-	1	-	-	-	-	-	-	-	-	10.99
2021	5	3.56	-	-	-	-	1	-	-	-	-	-	-	-	10.99
2021	6	3.56	-	-	-	-	-	1	-	-	-	-	-	-	11.00
2021	7	3.56	-	-	-	-	-	-	1	-	-	-	-	-	11.00
2021	8	3.56	-	-	-	-	-	-	-	1	-	-	-	-	11.00
2021	9	3.56	-	-	-	-	-	-	-	-	1	-	-	-	11.00
2021	10	3.56	-	-	-	-	-	-	-	-	-	1	-	-	11.00
2021	11	3.56	-	-	-	-	-	-	-	-	-	-	1	-	11.00
2021	12	3.56	-	-	-	-	-	-	-	-	-	-	-	1	11.00
2022	1	3.56	1	-	-	-	-	-	-	-	-	-	-	-	11.00
2022	2	3.56	-	1	-	-	-	-	-	-	-	-	-	-	11.00
2022	3	3.57	-	-	1	-	-	-	-	-	-	-	-	-	11.00
2022	4	3.57	-	-	-	1	-	-	-	-	-	-	-	-	11.00
2022	5	3.57	-	-	-	-	1	-	-	-	-	-	-	-	11.00
2022	6	3.57	-	-	-	-	-	1	-	-	-	-	-	-	11.01
2022	7	3.57	-	-	-	-	-	-	1	-	-	-	-	-	11.01
2022	8	3.57	-	-	-	-	-	-	-	1	-	-	-	-	11.01
2022	9	3.57	-	-	-	-	-	-	-	-	1	-	-	-	11.01
2022	10	3.57	-	-	-	-	-	-	-	-	-	1	-	-	11.01
2022	11	3.57	-	-	-	-	-	-	-	-	-	-	1	-	11.01
2022	12	3.57	-	-	-	-	-	-	-	-	-	-	-	1	11.01
2023	1	3.57	1	-	-	-	-	-	-	-	-	-	-	-	11.01
2023	2	3.58	-	1	-	-	-	-	-	-	-	-	-	-	11.01
2023	3	3.58	-	-	1	-	-	-	-	-	-	-	-	-	11.01
2023	4	3.58	-	-	-	1	-	-	-	-	-	-	-	-	11.01
2023	5	3.58	-	-	-	-	1	-	-	-	-	-	-	-	11.01
2023	6	3.58	-	-	-	-	-	1	-	-	-	-	-	-	11.02
2023	7	3.58	-	-	-	-	-	-	1	-	-	-	-	-	11.02
2023	8	3.58	-	-	-	-	-	-	-	1	-	-	-	-	11.02
2023	9	3.58	-	-	-	-	-	-	-	-	1	-	-	-	11.02
2023	10	3.58	-	-	-	-	-	-	-	-	-	1	-	-	11.02
2023	11	3.58	-	-	-	-	-	-	-	-	-	-	1	-	11.02
2023	12	3.58	-	-	-	-	-	-	-	-	-	-	-	1	11.02
2024	1	3.58	1	-	-	-	-	-	-	-	-	-	-	-	11.02
2024	2	3.59	-	1	-	-	-	-	-	-	-	-	-	-	11.02

2024	3	3.59	-	-	1	-	-	-	-	-	-	-	-	-	11.02
2024	4	3.59	-	-	-	1	-	-	-	-	-	-	-	-	11.02
2024	5	3.59	-	-	-	-	1	-	-	-	-	-	-	-	11.02
2024	6	3.59	-	-	-	-	-	1	-	-	-	-	-	-	11.02
2024	7	3.59	-	-	-	-	-	-	1	-	-	-	-	-	11.02
2024	8	3.59	-	-	-	-	-	-	-	1	-	-	-	-	11.03
2024	9	3.59	-	-	-	-	-	-	-	-	1	-	-	-	11.03
2024	10	3.59	-	-	-	-	-	-	-	-	-	1	-	-	11.03
2024	11	3.59	-	-	-	-	-	-	-	-	-	-	1	-	11.03
2024	12	3.59	-	-	-	-	-	-	-	-	-	-	-	1	11.03
2025	1	3.59	1	-	-	-	-	-	-	-	-	-	-	-	11.03
2025	2	3.60	-	1	-	-	-	-	-	-	-	-	-	-	11.03
2025	3	3.60	-	-	1	-	-	-	-	-	-	-	-	-	11.03
2025	4	3.60	-	-	-	1	-	-	-	-	-	-	-	-	11.03
2025	5	3.60	-	-	-	-	1	-	-	-	-	-	-	-	11.03
2025	6	3.60	-	-	-	-	-	1	-	-	-	-	-	-	11.03
2025	7	3.60	-	-	-	-	-	-	1	-	-	-	-	-	11.03
2025	8	3.60	-	-	-	-	-	-	-	1	-	-	-	-	11.04
2025	9	3.60	-	-	-	-	-	-	-	-	1	-	-	-	11.04
2025	10	3.60	-	-	-	-	-	-	-	-	-	1	-	-	11.04
2025	11	3.60	-	-	-	-	-	-	-	-	-	-	1	-	11.04
2025	12	3.60	-	-	-	-	-	-	-	-	-	-	-	1	11.04
2026	1	3.60	1	-	-	-	-	-	-	-	-	-	-	-	11.04
2026	2	3.61	-	1	-	-	-	-	-	-	-	-	-	-	11.04
2026	3	3.61	-	-	1	-	-	-	-	-	-	-	-	-	11.04
2026	4	3.61	-	-	-	1	-	-	-	-	-	-	-	-	11.04
2026	5	3.61	-	-	-	-	1	-	-	-	-	-	-	-	11.04
2026	6	3.61	-	-	-	-	-	1	-	-	-	-	-	-	11.04
2026	7	3.61	-	-	-	-	-	-	1	-	-	-	-	-	11.04
2026	8	3.61	-	-	-	-	-	-	-	1	-	-	-	-	11.04
2026	9	3.61	-	-	-	-	-	-	-	-	1	-	-	-	11.05
2026	10	3.61	-	-	-	-	-	-	-	-	-	1	-	-	11.05
2026	11	3.61	-	-	-	-	-	-	-	-	-	-	1	-	11.05
2026	12	3.61	-	-	-	-	-	-	-	-	-	-	-	1	11.05
2027	1	3.62	1	-	-	-	-	-	-	-	-	-	-	-	11.05

2027	2	3.62	-	1	-	-	-	-	-	-	-	-	-	-	11.05
2027	3	3.62	-	-	1	-	-	-	-	-	-	-	-	-	11.05
2027	4	3.62	-	-	-	1	-	-	-	-	-	-	-	-	11.05
2027	5	3.62	-	-	-	-	1	-	-	-	-	-	-	-	11.05
2027	6	3.62	-	-	-	-	-	1	-	-	-	-	-	-	11.05
2027	7	3.62	-	-	-	-	-	-	1	-	-	-	-	-	11.05
2027	8	3.62	-	-	-	-	-	-	-	1	-	-	-	-	11.05
2027	9	3.62	-	-	-	-	-	-	-	-	1	-	-	-	11.05
2027	10	3.62	-	-	-	-	-	-	-	-	-	1	-	-	11.05
2027	11	3.62	-	-	-	-	-	-	-	-	-	-	1	-	11.05
2027	12	3.62	-	-	-	-	-	-	-	-	-	-	-	1	11.06
2028	1	3.62	1	-	-	-	-	-	-	-	-	-	-	-	11.06
2028	2	3.63	-	1	-	-	-	-	-	-	-	-	-	-	11.06
2028	3	3.63	-	-	1	-	-	-	-	-	-	-	-	-	11.06
2028	4	3.63	-	-	-	1	-	-	-	-	-	-	-	-	11.06
2028	5	3.63	-	-	-	-	1	-	-	-	-	-	-	-	11.06
2028	6	3.63	-	-	-	-	-	1	-	-	-	-	-	-	11.06
2028	7	3.63	-	-	-	-	-	-	1	-	-	-	-	-	11.06
2028	8	3.63	-	-	-	-	-	-	-	1	-	-	-	-	11.06
2028	9	3.63	-	-	-	-	-	-	-	-	1	-	-	-	11.06
2028	10	3.63	-	-	-	-	-	-	-	-	-	1	-	-	11.06
2028	11	3.63	-	-	-	-	-	-	-	-	-	-	1	-	11.06
2028	12	3.63	-	-	-	-	-	-	-	-	-	-	-	1	11.06
2029	1	3.63	1	-	-	-	-	-	-	-	-	-	-	-	11.06
2029	2	3.64	-	1	-	-	-	-	-	-	-	-	-	-	11.06
2029	3	3.64	-	-	1	-	-	-	-	-	-	-	-	-	11.07
2029	4	3.64	-	-	-	1	-	-	-	-	-	-	-	-	11.07
2029	5	3.64	-	-	-	-	1	-	-	-	-	-	-	-	11.07
2029	6	3.64	-	-	-	-	-	1	-	-	-	-	-	-	11.07
2029	7	3.64	-	-	-	-	-	-	1	-	-	-	-	-	11.07
2029	8	3.64	-	-	-	-	-	-	-	1	-	-	-	-	11.07
2029	9	3.64	-	-	-	-	-	-	-	-	1	-	-	-	11.07
2029	10	3.64	-	-	-	-	-	-	-	-	-	1	-	-	11.07
2029	11	3.64	-	-	-	-	-	-	-	-	-	-	1	-	11.07
2029	12	3.64	-	-	-	-	-	-	-	-	-	-	-	1	11.07

2030	1	3.64	1	-	-	-	-	-	-	-	-	-	-	-	11.07
2030	2	3.64	-	1	-	-	-	-	-	-	-	-	-	-	11.07
2030	3	3.65	-	-	1	-	-	-	-	-	-	-	-	-	11.07
2030	4	3.65	-	-	-	1	-	-	-	-	-	-	-	-	11.07
2030	5	3.65	-	-	-	-	1	-	-	-	-	-	-	-	11.07
2030	6	3.65	-	-	-	-	-	1	-	-	-	-	-	-	11.08
2030	7	3.65	-	-	-	-	-	-	1	-	-	-	-	-	11.08
2030	8	3.65	-	-	-	-	-	-	-	1	-	-	-	-	11.08
2030	9	3.65	-	-	-	-	-	-	-	-	1	-	-	-	11.08
2030	10	3.65	-	-	-	-	-	-	-	-	-	1	-	-	11.08
2030	11	3.65	-	-	-	-	-	-	-	-	-	-	1	-	11.08
2030	12	3.65	-	-	-	-	-	-	-	-	-	-	-	1	11.08
2031	1	3.65	1	-	-	-	-	-	-	-	-	-	-	-	11.08
2031	2	3.65	-	1	-	-	-	-	-	-	-	-	-	-	11.08
2031	3	3.65	-	-	1	-	-	-	-	-	-	-	-	-	11.08
2031	4	3.65	-	-	-	1	-	-	-	-	-	-	-	-	11.08
2031	5	3.66	-	-	-	-	1	-	-	-	-	-	-	-	11.08
2031	6	3.66	-	-	-	-	-	1	-	-	-	-	-	-	11.08
2031	7	3.66	-	-	-	-	-	-	1	-	-	-	-	-	11.08
2031	8	3.66	-	-	-	-	-	-	-	1	-	-	-	-	11.09
2031	9	3.66	-	-	-	-	-	-	-	-	1	-	-	-	11.09
2031	10	3.66	-	-	-	-	-	-	-	-	-	1	-	-	11.09
2031	11	3.66	-	-	-	-	-	-	-	-	-	-	1	-	11.09
2031	12	3.66	-	-	-	-	-	-	-	-	-	-	-	1	11.09
2032	1	3.66	1	-	-	-	-	-	-	-	-	-	-	-	11.09
2032	2	3.66	-	1	-	-	-	-	-	-	-	-	-	-	11.09
2032	3	3.66	-	-	1	-	-	-	-	-	-	-	-	-	11.09
2032	4	3.66	-	-	-	1	-	-	-	-	-	-	-	-	11.09
2032	5	3.66	-	-	-	-	1	-	-	-	-	-	-	-	11.09
2032	6	3.66	-	-	-	-	-	1	-	-	-	-	-	-	11.09
2032	7	3.67	-	-	-	-	-	-	1	-	-	-	-	-	11.09
2032	8	3.67	-	-	-	-	-	-	-	1	-	-	-	-	11.09
2032	9	3.67	-	-	-	-	-	-	-	-	1	-	-	-	11.09
2032	10	3.67	-	-	-	-	-	-	-	-	-	1	-	-	11.09
2032	11	3.67	-	-	-	-	-	-	-	-	-	-	1	-	11.09

2032	12	3.67	-	-	-	-	-	-	-	-	-	-	-	1	11.10
2033	1	3.67	1	-	-	-	-	-	-	-	-	-	-	-	11.10
2033	2	3.67	-	1	-	-	-	-	-	-	-	-	-	-	11.10
2033	3	3.67	-	-	1	-	-	-	-	-	-	-	-	-	11.10
2033	4	3.67	-	-	-	1	-	-	-	-	-	-	-	-	11.10
2033	5	3.67	-	-	-	-	1	-	-	-	-	-	-	-	11.10
2033	6	3.67	-	-	-	-	-	1	-	-	-	-	-	-	11.10
2033	7	3.67	-	-	-	-	-	-	1	-	-	-	-	-	11.10
2033	8	3.67	-	-	-	-	-	-	-	1	-	-	-	-	11.10
2033	9	3.67	-	-	-	-	-	-	-	-	1	-	-	-	11.10
2033	10	3.68	-	-	-	-	-	-	-	-	-	1	-	-	11.10
2033	11	3.68	-	-	-	-	-	-	-	-	-	-	1	-	11.10
2033	12	3.68	-	-	-	-	-	-	-	-	-	-	-	1	11.10
2034	1	3.68	1	-	-	-	-	-	-	-	-	-	-	-	11.10
2034	2	3.68	-	1	-	-	-	-	-	-	-	-	-	-	11.10
2034	3	3.68	-	-	1	-	-	-	-	-	-	-	-	-	11.10
2034	4	3.68	-	-	-	1	-	-	-	-	-	-	-	-	11.10
2034	5	3.68	-	-	-	-	1	-	-	-	-	-	-	-	11.10
2034	6	3.68	-	-	-	-	-	1	-	-	-	-	-	-	11.11
2034	7	3.68	-	-	-	-	-	-	1	-	-	-	-	-	11.11
2034	8	3.68	-	-	-	-	-	-	-	1	-	-	-	-	11.11
2034	9	3.68	-	-	-	-	-	-	-	-	1	-	-	-	11.11
2034	10	3.68	-	-	-	-	-	-	-	-	-	1	-	-	11.11
2034	11	3.68	-	-	-	-	-	-	-	-	-	-	1	-	11.11
2034	12	3.68	-	-	-	-	-	-	-	-	-	-	-	1	11.11
2035	1	3.69	1	-	-	-	-	-	-	-	-	-	-	-	11.11
2035	2	3.69	-	1	-	-	-	-	-	-	-	-	-	-	11.11
2035	3	3.69	-	-	1	-	-	-	-	-	-	-	-	-	11.11
2035	4	3.69	-	-	-	1	-	-	-	-	-	-	-	-	11.11
2035	5	3.69	-	-	-	-	1	-	-	-	-	-	-	-	11.11
2035	6	3.69	-	-	-	-	-	1	-	-	-	-	-	-	11.11
2035	7	3.69	-	-	-	-	-	-	1	-	-	-	-	-	11.11
2035	8	3.69	-	-	-	-	-	-	-	1	-	-	-	-	11.11
2035	9	3.69	-	-	-	-	-	-	-	-	1	-	-	-	11.11
2035	10	3.69	-	-	-	-	-	-	-	-	-	1	-	-	11.11

2035	11	3.69	-	-	-	-	-	-	-	-	-	-	1	-	11.11
2035	12	3.69	-	-	-	-	-	-	-	-	-	-	-	1	11.12
2036	1	3.69	1	-	-	-	-	-	-	-	-	-	-	-	11.12
2036	2	3.69	-	1	-	-	-	-	-	-	-	-	-	-	11.12
2036	3	3.69	-	-	1	-	-	-	-	-	-	-	-	-	11.12
2036	4	3.69	-	-	-	1	-	-	-	-	-	-	-	-	11.12
2036	5	3.70	-	-	-	-	1	-	-	-	-	-	-	-	11.12
2036	6	3.70	-	-	-	-	-	1	-	-	-	-	-	-	11.12
2036	7	3.70	-	-	-	-	-	-	1	-	-	-	-	-	11.12
2036	8	3.70	-	-	-	-	-	-	-	1	-	-	-	-	11.12
2036	9	3.70	-	-	-	-	-	-	-	-	1	-	-	-	11.12
2036	10	3.70	-	-	-	-	-	-	-	-	-	1	-	-	11.12
2036	11	3.70	-	-	-	-	-	-	-	-	-	-	1	-	11.12
2036	12	3.70	-	-	-	-	-	-	-	-	-	-	-	1	11.12
2037	1	3.70	1	-	-	-	-	-	-	-	-	-	-	-	11.12
2037	2	3.70	-	1	-	-	-	-	-	-	-	-	-	-	11.12
2037	3	3.70	-	-	1	-	-	-	-	-	-	-	-	-	11.12
2037	4	3.70	-	-	-	1	-	-	-	-	-	-	-	-	11.12
2037	5	3.70	-	-	-	-	1	-	-	-	-	-	-	-	11.12
2037	6	3.70	-	-	-	-	-	1	-	-	-	-	-	-	11.12
2037	7	3.70	-	-	-	-	-	-	1	-	-	-	-	-	11.12
2037	8	3.70	-	-	-	-	-	-	-	1	-	-	-	-	11.13
2037	9	3.70	-	-	-	-	-	-	-	-	1	-	-	-	11.13
2037	10	3.70	-	-	-	-	-	-	-	-	-	1	-	-	11.13
2037	11	3.71	-	-	-	-	-	-	-	-	-	-	1	-	11.13
2037	12	3.71	-	-	-	-	-	-	-	-	-	-	-	1	11.13
2038	1	3.71	1	-	-	-	-	-	-	-	-	-	-	-	11.13
2038	2	3.71	-	1	-	-	-	-	-	-	-	-	-	-	11.13
2038	3	3.71	-	-	1	-	-	-	-	-	-	-	-	-	11.13
2038	4	3.71	-	-	-	1	-	-	-	-	-	-	-	-	11.13
2038	5	3.71	-	-	-	-	1	-	-	-	-	-	-	-	11.13
2038	6	3.71	-	-	-	-	-	1	-	-	-	-	-	-	11.13
2038	7	3.71	-	-	-	-	-	-	1	-	-	-	-	-	11.13
2038	8	3.71	-	-	-	-	-	-	-	1	-	-	-	-	11.13
2038	9	3.71	-	-	-	-	-	-	-	-	1	-	-	-	11.13

2038	10	3.71	-	-	-	-	-	-	-	-	-	1	-	-	11.13
2038	11	3.71	-	-	-	-	-	-	-	-	-	-	1	-	11.13
2038	12	3.71	-	-	-	-	-	-	-	-	-	-	-	1	11.13
2039	1	3.71	1	-	-	-	-	-	-	-	-	-	-	-	11.13
2039	2	3.71	-	1	-	-	-	-	-	-	-	-	-	-	11.13
2039	3	3.71	-	-	1	-	-	-	-	-	-	-	-	-	11.14
2039	4	3.72	-	-	-	1	-	-	-	-	-	-	-	-	11.14
2039	5	3.72	-	-	-	-	1	-	-	-	-	-	-	-	11.14
2039	6	3.72	-	-	-	-	-	1	-	-	-	-	-	-	11.14
2039	7	3.72	-	-	-	-	-	-	1	-	-	-	-	-	11.14
2039	8	3.72	-	-	-	-	-	-	-	1	-	-	-	-	11.14
2039	9	3.72	-	-	-	-	-	-	-	-	1	-	-	-	11.14
2039	10	3.72	-	-	-	-	-	-	-	-	-	1	-	-	11.14
2039	11	3.72	-	-	-	-	-	-	-	-	-	-	1	-	11.14
2039	12	3.72	-	-	-	-	-	-	-	-	-	-	-	1	11.14
2040	1	3.72	1	-	-	-	-	-	-	-	-	-	-	-	11.14
2040	2	3.72	-	1	-	-	-	-	-	-	-	-	-	-	11.14
2040	3	3.72	-	-	1	-	-	-	-	-	-	-	-	-	11.14
2040	4	3.72	-	-	-	1	-	-	-	-	-	-	-	-	11.14
2040	5	3.72	-	-	-	-	1	-	-	-	-	-	-	-	11.14
2040	6	3.72	-	-	-	-	-	1	-	-	-	-	-	-	11.14
2040	7	3.72	-	-	-	-	-	-	1	-	-	-	-	-	11.14
2040	8	3.72	-	-	-	-	-	-	-	1	-	-	-	-	11.14
2040	9	3.72	-	-	-	-	-	-	-	-	1	-	-	-	11.15
2040	10	3.72	-	-	-	-	-	-	-	-	-	1	-	-	11.15
2040	11	3.73	-	-	-	-	-	-	-	-	-	-	1	-	11.15
2040	12	3.73	-	-	-	-	-	-	-	-	-	-	-	1	11.15

Schedule C-13. Black Hills Power: Variable Statistical Values for Residential Customer Model

Black Hills Power **Confidential Appendix C**

Black Hills Power: Variable Statistical Values for Residential Customer Model **Schedule C-13**

Variable	Coefficient	Standard Error	P Value	R2 = 1.0000
lntotemp12	0.883	0.045	0.000	
m2	0.000	0.001	0.752	
m3	0.001	0.001	0.384	
m4	0.000	0.001	0.890	
m5	0.000	0.001	0.836	
m6	0.000	0.001	0.643	
m7	0.000	0.001	0.766	
m8	0.001	0.001	0.229	
m9	0.002	0.001	0.100	
m10	0.001	0.001	0.180	
m11	0.001	0.001	0.381	
m12	0.001	0.001	0.013	
_cons	7.854	0.158	0.000	

Schedule C-14. Black Hills Power: Historical and Forecasted Variable Values for Commercial Use Per Customer Model

Black Hills Power | **Confidential Appendix C**

Black Hills Power: Historical and Forecasted Variable Values for Commercial Use Per Customer Model | **Schedule C-14**

Year	Month	cdd60	hdd60	class_shift	lntotemp12	trend	m1	m2	m3	m4	m5	m6	m7	m8	m9	m10	m11	m12	ln(upc)
1999	1	-	528	-	3.29	1.08	1	-	-	-	-	-	-	-	-	-	-	-	8.45
1999	2	-	856	-	3.29	1.17	-	1	-	-	-	-	-	-	-	-	-	-	8.43
1999	3	-	762	-	3.29	1.25	-	-	1	-	-	-	-	-	-	-	-	-	8.43
1999	4	-	585	-	3.30	1.33	-	-	-	1	-	-	-	-	-	-	-	-	8.37
1999	5	-	358	-	3.30	1.42	-	-	-	-	1	-	-	-	-	-	-	-	8.34
1999	6	49	77	-	3.30	1.50	-	-	-	-	-	1	-	-	-	-	-	-	8.41
1999	7	218	9	-	3.30	1.58	-	-	-	-	-	-	1	-	-	-	-	-	8.50
1999	8	347	-	-	3.30	1.67	-	-	-	-	-	-	-	1	-	-	-	-	8.57
1999	9	207	66	-	3.30	1.75	-	-	-	-	-	-	-	-	1	-	-	-	8.49
1999	10	29	212	-	3.30	1.83	-	-	-	-	-	-	-	-	-	1	-	-	8.39
1999	11	5	264	-	3.31	1.92	-	-	-	-	-	-	-	-	-	-	1	-	8.33
1999	12	-	703	-	3.31	2.00	-	-	-	-	-	-	-	-	-	-	-	1	8.46
2000	1	-	831	-	3.31	2.08	1	-	-	-	-	-	-	-	-	-	-	-	8.48
2000	2	-	971	-	3.31	2.17	-	1	-	-	-	-	-	-	-	-	-	-	8.44
2000	3	-	614	-	3.32	2.25	-	-	1	-	-	-	-	-	-	-	-	-	8.42
2000	4	-	575	-	3.32	2.33	-	-	-	1	-	-	-	-	-	-	-	-	8.37
2000	5	20	264	-	3.32	2.42	-	-	-	-	1	-	-	-	-	-	-	-	8.34
2000	6	112	74	-	3.32	2.50	-	-	-	-	-	1	-	-	-	-	-	-	8.44
2000	7	297	16	-	3.32	2.58	-	-	-	-	-	-	1	-	-	-	-	-	8.54
2000	8	434	-	-	3.33	2.67	-	-	-	-	-	-	-	1	-	-	-	-	8.61
2000	9	328	-	-	3.33	2.75	-	-	-	-	-	-	-	-	1	-	-	-	8.54
2000	10	66	295	-	3.33	2.83	-	-	-	-	-	-	-	-	-	1	-	-	8.42
2000	11	5	632	-	3.33	2.92	-	-	-	-	-	-	-	-	-	-	1	-	8.37
2000	12	-	1,061	-	3.34	3.00	-	-	-	-	-	-	-	-	-	-	-	1	8.50
2001	1	-	1,037	-	3.34	3.08	1	-	-	-	-	-	-	-	-	-	-	-	8.50
2001	2	-	1,147	-	3.34	3.17	-	1	-	-	-	-	-	-	-	-	-	-	8.46
2001	3	-	892	-	3.34	3.25	-	-	1	-	-	-	-	-	-	-	-	-	8.45
2001	4	-	670	-	3.34	3.33	-	-	-	1	-	-	-	-	-	-	-	-	8.39
2001	5	62	231	-	3.34	3.42	-	-	-	-	1	-	-	-	-	-	-	-	8.36
2001	6	44	100	-	3.34	3.50	-	-	-	-	-	1	-	-	-	-	-	-	8.42
2001	7	336	5	-	3.34	3.58	-	-	-	-	-	-	1	-	-	-	-	-	8.56

2001	8	475	-	-	3.34	3.67	-	-	-	-	-	-	-	1	-	-	-	-	8.63
2001	9	306	36	-	3.34	3.75	-	-	-	-	-	-	-	-	1	-	-	-	8.53
2001	10	53	187	-	3.34	3.83	-	-	-	-	-	-	-	-	-	1	-	-	8.40
2001	11	-	324	-	3.35	3.92	-	-	-	-	-	-	-	-	-	-	1	-	8.34
2001	12	-	788	-	3.35	4.00	-	-	-	-	-	-	-	-	-	-	-	1	8.47
2002	1	-	937	-	3.35	4.08	1	-	-	-	-	-	-	-	-	-	-	-	8.49
2002	2	-	915	-	3.35	4.17	-	1	-	-	-	-	-	-	-	-	-	-	8.44
2002	3	-	956	-	3.35	4.25	-	-	1	-	-	-	-	-	-	-	-	-	8.46
2002	4	6	793	-	3.35	4.33	-	-	-	1	-	-	-	-	-	-	-	-	8.40
2002	5	0	450	-	3.35	4.42	-	-	-	-	1	-	-	-	-	-	-	-	8.35
2002	6	80	114	-	3.35	4.50	-	-	-	-	-	1	-	-	-	-	-	-	8.43
2002	7	471	-	-	3.35	4.58	-	-	-	-	-	-	1	-	-	-	-	-	8.61
2002	8	437	-	-	3.36	4.67	-	-	-	-	-	-	-	1	-	-	-	-	8.61
2002	9	298	1	-	3.36	4.75	-	-	-	-	-	-	-	-	1	-	-	-	8.53
2002	10	20	286	-	3.36	4.83	-	-	-	-	-	-	-	-	-	1	-	-	8.40
2002	11	-	720	-	3.36	4.92	-	-	-	-	-	-	-	-	-	-	1	-	8.38
2002	12	-	682	-	3.36	5.00	-	-	-	-	-	-	-	-	-	-	-	1	8.47
2003	1	-	871	-	3.36	5.08	1	-	-	-	-	-	-	-	-	-	-	-	8.49
2003	2	-	1,086	-	3.36	5.17	-	1	-	-	-	-	-	-	-	-	-	-	8.46
2003	3	-	936	-	3.36	5.25	-	-	1	-	-	-	-	-	-	-	-	-	8.46
2003	4	10	475	-	3.36	5.33	-	-	-	1	-	-	-	-	-	-	-	-	8.37
2003	5	-	344	-	3.36	5.42	-	-	-	-	1	-	-	-	-	-	-	-	8.34
2003	6	75	91	-	3.36	5.50	-	-	-	-	-	1	-	-	-	-	-	-	8.43
2003	7	317	16	-	3.36	5.58	-	-	-	-	-	-	1	-	-	-	-	-	8.55
2003	8	568	-	-	3.36	5.67	-	-	-	-	-	-	-	1	-	-	-	-	8.67
2003	9	343	22	-	3.37	5.75	-	-	-	-	-	-	-	-	1	-	-	-	8.54
2003	10	32	184	-	3.37	5.83	-	-	-	-	-	-	-	-	-	1	-	-	8.39
2003	11	32	657	-	3.37	5.92	-	-	-	-	-	-	-	-	-	-	1	-	8.38
2003	12	-	830	-	3.37	6.00	-	-	-	-	-	-	-	-	-	-	-	1	8.48
2004	1	-	910	-	3.37	6.08	1	-	-	-	-	-	-	-	-	-	-	-	8.49
2004	2	-	1,196	-	3.37	6.17	-	1	-	-	-	-	-	-	-	-	-	-	8.46
2004	3	-	694	-	3.37	6.25	-	-	1	-	-	-	-	-	-	-	-	-	8.43
2004	4	-	378	-	3.37	6.33	-	-	-	1	-	-	-	-	-	-	-	-	8.36
2004	5	29	258	-	3.37	6.42	-	-	-	-	1	-	-	-	-	-	-	-	8.35
2004	6	77	100	-	3.37	6.50	-	-	-	-	-	1	-	-	-	-	-	-	8.43

2004	7	207	33	-	3.37	6.58	-	-	-	-	-	-	1	-	-	-	-	-	8.50
2004	8	335	3	-	3.37	6.67	-	-	-	-	-	-	-	1	-	-	-	-	8.57
2004	9	231	13	-	3.38	6.75	-	-	-	-	-	-	-	-	1	-	-	-	8.50
2004	10	50	136	-	3.38	6.83	-	-	-	-	-	-	-	-	-	1	-	-	8.39
2004	11	-	463	-	3.38	6.92	-	-	-	-	-	-	-	-	-	-	1	-	8.35
2004	12	-	736	-	3.38	7.00	-	-	-	-	-	-	-	-	-	-	-	1	8.47
2005	1	-	1,252	-	3.38	7.08	1	-	-	-	-	-	-	-	-	-	-	-	8.52
2005	2	-	743	-	3.38	7.17	-	1	-	-	-	-	-	-	-	-	-	-	8.42
2005	3	-	649	-	3.38	7.25	-	-	1	-	-	-	-	-	-	-	-	-	8.43
2005	4	4	510	-	3.38	7.33	-	-	-	1	-	-	-	-	-	-	-	-	8.37
2005	5	10	435	-	3.38	7.42	-	-	-	-	1	-	-	-	-	-	-	-	8.35
2005	6	58	79	-	3.39	7.50	-	-	-	-	-	1	-	-	-	-	-	-	8.42
2005	7	422	-	-	3.39	7.58	-	-	-	-	-	-	1	-	-	-	-	-	8.59
2005	8	433	8	-	3.39	7.67	-	-	-	-	-	-	-	1	-	-	-	-	8.61
2005	9	293	6	-	3.39	7.75	-	-	-	-	-	-	-	-	1	-	-	-	8.52
2005	10	59	195	-	3.39	7.83	-	-	-	-	-	-	-	-	-	1	-	-	8.40
2005	11	4	405	-	3.39	7.92	-	-	-	-	-	-	-	-	-	-	1	-	8.35
2005	12	-	943	-	3.39	8.00	-	-	-	-	-	-	-	-	-	-	-	1	8.49
2006	1	-	734	-	3.39	8.08	1	-	-	-	-	-	-	-	-	-	-	-	8.47
2006	2	-	811	-	3.40	8.17	-	1	-	-	-	-	-	-	-	-	-	-	8.43
2006	3	-	852	-	3.40	8.25	-	-	1	-	-	-	-	-	-	-	-	-	8.45
2006	4	10	555	-	3.40	8.33	-	-	-	1	-	-	-	-	-	-	-	-	8.38
2006	5	0	345	-	3.40	8.42	-	-	-	-	1	-	-	-	-	-	-	-	8.34
2006	6	228	12	-	3.40	8.50	-	-	-	-	-	1	-	-	-	-	-	-	8.48
2006	7	384	-	-	3.40	8.58	-	-	-	-	-	-	1	-	-	-	-	-	8.57
2006	8	532	-	-	3.40	8.67	-	-	-	-	-	-	-	1	-	-	-	-	8.65
2006	9	224	21	-	3.40	8.75	-	-	-	-	-	-	-	-	1	-	-	-	8.50
2006	10	31	294	-	3.41	8.83	-	-	-	-	-	-	-	-	-	1	-	-	8.40
2006	11	4	610	-	3.41	8.92	-	-	-	-	-	-	-	-	-	-	1	-	8.36
2006	12	-	788	-	3.41	9.00	-	-	-	-	-	-	-	-	-	-	-	1	8.47
2007	1	-	992	-	3.41	9.08	1	-	-	-	-	-	-	-	-	-	-	-	8.50
2007	2	-	1,200	-	3.41	9.17	-	1	-	-	-	-	-	-	-	-	-	-	8.46
2007	3	1	623	-	3.41	9.25	-	-	1	-	-	-	-	-	-	-	-	-	8.43
2007	4	-	587	-	3.42	9.33	-	-	-	1	-	-	-	-	-	-	-	-	8.38
2007	5	38	163	-	3.42	9.42	-	-	-	-	1	-	-	-	-	-	-	-	8.34

2007	6	111	76	-	3.42	9.50	-	-	-	-	-	1	-	-	-	-	-	-	8.44
2007	7	434	-	-	3.42	9.58	-	-	-	-	-	-	1	-	-	-	-	-	8.60
2007	8	582	-	-	3.42	9.67	-	-	-	-	-	-	-	1	-	-	-	-	8.68
2007	9	234	42	-	3.43	9.75	-	-	-	-	-	-	-	-	1	-	-	-	8.51
2007	10	72	138	-	3.43	9.83	-	-	-	-	-	-	-	-	-	1	-	-	8.41
2007	11	3	402	-	3.43	9.92	-	-	-	-	-	-	-	-	-	-	1	-	8.35
2007	12	-	951	-	3.43	10.00	-	-	-	-	-	-	-	-	-	-	-	1	8.49
2008	1	-	949	-	3.43	10.08	1	-	-	-	-	-	-	-	-	-	-	-	8.50
2008	2	-	1,269	-	3.44	10.17	-	1	-	-	-	-	-	-	-	-	-	-	8.48
2008	3	-	776	-	3.44	10.25	-	-	1	-	-	-	-	-	-	-	-	-	8.45
2008	4	3	690	-	3.44	10.33	-	-	-	1	-	-	-	-	-	-	-	-	8.39
2008	5	-	403	-	3.44	10.42	-	-	-	-	1	-	-	-	-	-	-	-	8.35
2008	6	28	137	-	3.44	10.50	-	-	-	-	-	1	-	-	-	-	-	-	8.42
2008	7	264	1	-	3.44	10.58	-	-	-	-	-	-	1	-	-	-	-	-	8.53
2008	8	407	0	-	3.44	10.67	-	-	-	-	-	-	-	1	-	-	-	-	8.61
2008	9	207	57	-	3.45	10.75	-	-	-	-	-	-	-	-	1	-	-	-	8.50
2008	10	91	175	-	3.45	10.83	-	-	-	-	-	-	-	-	-	1	-	-	8.42
2008	11	4	488	-	3.45	10.92	-	-	-	-	-	-	-	-	-	-	1	-	8.36
2008	12	-	869	-	3.45	11.00	-	-	-	-	-	-	-	-	-	-	-	1	8.49
2009	1	-	1,216	-	3.45	11.08	1	-	-	-	-	-	-	-	-	-	-	-	8.52
2009	2	-	876	-	3.45	11.17	-	1	-	-	-	-	-	-	-	-	-	-	8.44
2009	3	-	888	-	3.45	11.25	-	-	1	-	-	-	-	-	-	-	-	-	8.46
2009	4	3	683	-	3.45	11.33	-	-	-	1	-	-	-	-	-	-	-	-	8.39
2009	5	7	346	-	3.45	11.42	-	-	-	-	1	-	-	-	-	-	-	-	8.35
2009	6	64	147	-	3.45	11.50	-	-	-	-	-	1	-	-	-	-	-	-	8.43
2009	7	269	-	-	3.45	11.58	-	-	-	-	-	-	1	-	-	-	-	-	8.53
2009	8	287	0	-	3.45	11.67	-	-	-	-	-	-	-	1	-	-	-	-	8.55
2009	9	216	5	-	3.45	11.75	-	-	-	-	-	-	-	-	1	-	-	-	8.49
2009	10	44	396	-	3.45	11.83	-	-	-	-	-	-	-	-	-	1	-	-	8.42
2009	11	2	499	-	3.45	11.92	-	-	-	-	-	-	-	-	-	-	1	-	8.35
2009	12	-	971	-	3.45	12.00	-	-	-	-	-	-	-	-	-	-	-	1	8.49
2010	1	-	1,133	-	3.44	12.08	1	-	-	-	-	-	-	-	-	-	-	-	8.51
2010	2	-	1,151	-	3.44	12.17	-	1	-	-	-	-	-	-	-	-	-	-	8.46
2010	3	-	832	-	3.44	12.25	-	-	1	-	-	-	-	-	-	-	-	-	8.44
2010	4	-	472	-	3.44	12.33	-	-	-	1	-	-	-	-	-	-	-	-	8.36

2010	5	-	412	-	3.44	12.42	-	-	-	-	1	-	-	-	-	-	-	-	8.34
2010	6	53	69	-	3.44	12.50	-	-	-	-	-	1	-	-	-	-	-	-	8.41
2010	7	267	0	-	3.44	12.58	-	-	-	-	-	-	1	-	-	-	-	-	8.52
2010	8	410	-	-	3.44	12.67	-	-	-	-	-	-	-	1	-	-	-	-	8.60
2010	9	261	3	-	3.44	12.75	-	-	-	-	-	-	-	-	1	-	-	-	8.50
2010	10	66	80	-	3.44	12.83	-	-	-	-	-	-	-	-	-	1	-	-	8.39
2010	11	3	384	-	3.44	12.92	-	-	-	-	-	-	-	-	-	-	1	-	8.34
2010	12	-	1,016	-	3.44	13.00	-	-	-	-	-	-	-	-	-	-	-	1	8.49
2011	1	-	1,196	-	3.44	13.08	1	-	-	-	-	-	-	-	-	-	-	-	8.51
2011	2	-	1,072	-	3.45	13.17	-	1	-	-	-	-	-	-	-	-	-	-	8.44
2011	3	-	1,027	-	3.45	13.25	-	-	1	-	-	-	-	-	-	-	-	-	8.45
2011	4	-	561	-	3.45	13.33	-	-	-	1	-	-	-	-	-	-	-	-	8.37
2011	5	0	419	-	3.45	13.42	-	-	-	-	1	-	-	-	-	-	-	-	8.34
2011	6	53	156	-	3.45	13.50	-	-	-	-	-	1	-	-	-	-	-	-	8.41
2011	7	256	1	-	3.45	13.58	-	-	-	-	-	-	1	-	-	-	-	-	8.51
2011	8	470	-	-	3.45	13.67	-	-	-	-	-	-	-	1	-	-	-	-	8.62
2011	9	308	32	-	3.45	13.75	-	-	-	-	-	-	-	-	1	-	-	-	8.52
2011	10	109	123	-	3.45	13.83	-	-	-	-	-	-	-	-	-	1	-	-	8.41
2011	11	-	533	-	3.45	13.92	-	-	-	-	-	-	-	-	-	-	1	-	8.35
2011	12	-	913	-	3.45	14.00	-	-	-	-	-	-	-	-	-	-	-	1	8.48
2012	1	-	746	-	3.45	14.08	1	-	-	-	-	-	-	-	-	-	-	-	8.47
2012	2	-	1,025	-	3.46	14.17	-	1	-	-	-	-	-	-	-	-	-	-	8.44
2012	3	-	674	-	3.46	14.25	-	-	1	-	-	-	-	-	-	-	-	-	8.42
2012	4	16	263	-	3.46	14.33	-	-	-	1	-	-	-	-	-	-	-	-	8.35
2012	5	36	179	-	3.46	14.42	-	-	-	-	1	-	-	-	-	-	-	-	8.33
2012	6	168	80	-	3.46	14.50	-	-	-	-	-	1	-	-	-	-	-	-	8.45
2012	7	467	-	-	3.46	14.58	-	-	-	-	-	-	1	-	-	-	-	-	8.60
2012	8	500	-	-	3.46	14.67	-	-	-	-	-	-	-	1	-	-	-	-	8.63
2012	9	350	1	-	3.46	14.75	-	-	-	-	-	-	-	-	1	-	-	-	8.54
2012	10	34	184	-	3.46	14.83	-	-	-	-	-	-	-	-	-	1	-	-	8.38
2012	11	2	559	-	3.46	14.92	-	-	-	-	-	-	-	-	-	-	1	-	8.35
2012	12	-	678	-	3.46	15.00	-	-	-	-	-	-	-	-	-	-	-	1	8.45
2013	1	-	1,127	-	3.47	15.08	1	-	-	-	-	-	-	-	-	-	-	-	8.50
2013	2	-	912	-	3.47	15.17	-	1	-	-	-	-	-	-	-	-	-	-	8.43
2013	3	-	740	-	3.47	15.25	-	-	1	-	-	-	-	-	-	-	-	-	8.43

2013	4	-	807	-	3.47	15.33	-	-	-	1	-	-	-	-	-	-	-	-	8.39
2013	5	27	409	-	3.47	15.42	-	-	-	-	1	-	-	-	-	-	-	-	8.35
2013	6	74	86	-	3.47	15.50	-	-	-	-	-	1	-	-	-	-	-	-	8.41
2013	7	354	-	-	3.47	15.58	-	-	-	-	-	-	1	-	-	-	-	-	8.55
2013	8	320	-	-	3.47	15.67	-	-	-	-	-	-	-	1	-	-	-	-	8.55
2013	9	448	-	-	3.47	15.75	-	-	-	-	-	-	-	-	1	-	-	-	8.57
2013	10	52	239	-	3.47	15.83	-	-	-	-	-	-	-	-	-	1	-	-	8.39
2013	11	-	603	-	3.47	15.92	-	-	-	-	-	-	-	-	-	-	1	-	8.35
2013	12	-	1,053	-	3.48	16.00	-	-	-	-	-	-	-	-	-	-	-	1	8.49
2014	1	-	1,047	-	3.48	16.08	1	-	-	-	-	-	-	-	-	-	-	-	8.49
2014	2	-	1,187	-	3.48	16.17	-	1	-	-	-	-	-	-	-	-	-	-	8.45
2014	3	-	900	-	3.48	16.25	-	-	1	-	-	-	-	-	-	-	-	-	8.44
2014	4	-	720	-	3.48	16.33	-	-	-	1	-	-	-	-	-	-	-	-	8.38
2014	5	-	374	-	3.48	16.42	-	-	-	-	1	-	-	-	-	-	-	-	8.33
2014	6	72	65	1	3.48	16.50	-	-	-	-	-	1	-	-	-	-	-	-	8.47
2014	7	232	-	1	3.48	16.58	-	-	-	-	-	-	1	-	-	-	-	-	8.56
2014	8	373	-	1	3.48	16.67	-	-	-	-	-	-	-	1	-	-	-	-	8.64
2014	9	169	100	1	3.49	16.75	-	-	-	-	-	-	-	-	1	-	-	-	8.53
2014	10	100	124	1	3.49	16.83	-	-	-	-	-	-	-	-	-	1	-	-	8.46
2014	11	5	545	1	3.49	16.92	-	-	-	-	-	-	-	-	-	-	1	-	8.41
2014	12	-	803	1	3.49	17.00	-	-	-	-	-	-	-	-	-	-	-	1	8.52
2015	1	-	1,170	1	3.49	17.08	1	-	-	-	-	-	-	-	-	-	-	-	8.56
2015	2	-	668	1	3.49	17.17	-	1	-	-	-	-	-	-	-	-	-	-	8.47
2015	3	8	786	1	3.49	17.25	-	-	1	-	-	-	-	-	-	-	-	-	8.49
2015	4	-	400	1	3.49	17.33	-	-	-	1	-	-	-	-	-	-	-	-	8.41
2015	5	5	326	1	3.49	17.42	-	-	-	-	1	-	-	-	-	-	-	-	8.39
2015	6	84	128	1	3.49	17.50	-	-	-	-	-	1	-	-	-	-	-	-	8.48
2015	7	296	-	1	3.49	17.58	-	-	-	-	-	-	1	-	-	-	-	-	8.58
2015	8	406	-	1	3.49	17.67	-	-	-	-	-	-	-	1	-	-	-	-	8.65
2015	9	277	8	1	3.49	17.75	-	-	-	-	-	-	-	-	1	-	-	-	8.56
2015	10	84	76	1	3.49	17.83	-	-	-	-	-	-	-	-	-	1	-	-	8.45
2015	11	4	402	1	3.49	17.92	-	-	-	-	-	-	-	-	-	-	1	-	8.39
2015	12	-	814	1	3.49	18.00	-	-	-	-	-	-	-	-	-	-	-	1	8.52
2016	1	-	1,128	1	3.49	18.08	1	-	-	-	-	-	-	-	-	-	-	-	8.55
2016	2	-	848	1	3.49	18.17	-	1	-	-	-	-	-	-	-	-	-	-	8.48

2016	3	-	456	1	3.49	18.25	-	-	1	-	-	-	-	-	-	-	-	-	8.46
2016	4	2	495	1	3.49	18.33	-	-	-	1	-	-	-	-	-	-	-	-	8.41
2016	5	15	368	1	3.50	18.42	-	-	-	-	1	-	-	-	-	-	-	-	8.39
2016	6	176	33	1	3.50	18.50	-	-	-	-	-	1	-	-	-	-	-	-	8.50
2016	7	386	-	1	3.50	18.58	-	-	-	-	-	-	1	-	-	-	-	-	8.62
2016	8	448	-	1	3.50	18.67	-	-	-	-	-	-	-	1	-	-	-	-	8.66
2016	9	201	23	1	3.50	18.75	-	-	-	-	-	-	-	-	1	-	-	-	8.53
2016	10	51	130	1	3.50	18.83	-	-	-	-	-	-	-	-	-	1	-	-	8.44
2016	11	11	208	1	3.50	18.92	-	-	-	-	-	-	-	-	-	-	1	-	8.38
2016	12	-	1,012	1	3.50	19.00	-	-	-	-	-	-	-	-	-	-	-	1	8.54
2017	1	-	1,317	1	3.50	19.08	1	-	-	-	-	-	-	-	-	-	-	-	8.57
2017	2	-	928	1	3.50	19.17	-	1	-	-	-	-	-	-	-	-	-	-	8.48
2017	3	-	665	1	3.50	19.25	-	-	1	-	-	-	-	-	-	-	-	-	8.47
2017	4	0	390	1	3.51	19.33	-	-	-	1	-	-	-	-	-	-	-	-	8.40
2017	5	34	289	1	3.51	19.42	-	-	-	-	1	-	-	-	-	-	-	-	8.39
2017	6	152	107	1	3.51	19.50	-	-	-	-	-	1	-	-	-	-	-	-	8.50
2017	7	357	0	1	3.51	19.58	-	-	-	-	-	-	1	-	-	-	-	-	8.60
2017	8	374	-	1	3.51	19.67	-	-	-	-	-	-	-	1	-	-	-	-	8.63
2017	9	342	11	1	3.51	19.75	-	-	-	-	-	-	-	-	1	-	-	-	8.59
2017	10	9	263	1	3.51	19.83	-	-	-	-	-	-	-	-	-	1	-	-	8.43
2017	11	11	546	1	3.51	19.92	-	-	-	-	-	-	-	-	-	-	1	-	8.41
2017	12	2	552	1	3.51	20.00	-	-	-	-	-	-	-	-	-	-	-	1	8.50
2018	1	-	1,294	1	3.51	20.08	1	-	-	-	-	-	-	-	-	-	-	-	8.57
2018	2	-	1,120	1	3.52	20.17	-	1	-	-	-	-	-	-	-	-	-	-	8.50
2018	3	-	986	1	3.52	20.25	-	-	1	-	-	-	-	-	-	-	-	-	8.50
2018	4	-	836	1	3.52	20.33	-	-	-	1	-	-	-	-	-	-	-	-	8.44
2018	5	24	259	1	3.52	20.42	-	-	-	-	1	-	-	-	-	-	-	-	8.39
2018	6	242	29	1	3.52	20.50	-	-	-	-	-	1	-	-	-	-	-	-	8.53
2018	7	281	12	1	3.52	20.58	-	-	-	-	-	-	1	-	-	-	-	-	8.57
2018	8	330	-	1	3.52	20.67	-	-	-	-	-	-	-	1	-	-	-	-	8.61
2018	9	228	6	1	3.52	20.75	-	-	-	-	-	-	-	-	1	-	-	-	8.54
2018	10	18	408	1	3.52	20.83	-	-	-	-	-	-	-	-	-	1	-	-	8.45
2018	11	-	553	1	3.53	20.92	-	-	-	-	-	-	-	-	-	-	1	-	8.40
2018	12	-	822	1	3.53	21.00	-	-	-	-	-	-	-	-	-	-	-	1	8.52
2019	1	-	892	1	3.53	21.08	1	-	-	-	-	-	-	-	-	-	-	-	8.53

2019	2	-	1,302	1	3.53	21.17	-	1	-	-	-	-	-	-	-	-	-	-	8.52
2019	3	-	1,303	1	3.53	21.25	-	-	1	-	-	-	-	-	-	-	-	-	8.53
2019	4	-	621	1	3.53	21.33	-	-	-	1	-	-	-	-	-	-	-	-	8.42
2019	5	11	382	1	3.53	21.42	-	-	-	-	1	-	-	-	-	-	-	-	8.39
2019	6	70	205	1	3.53	21.50	-	-	-	-	-	1	-	-	-	-	-	-	8.48
2019	7	217	2	1	3.53	21.58	-	-	-	-	-	-	1	-	-	-	-	-	8.55
2019	8	318	-	1	3.54	21.67	-	-	-	-	-	-	-	1	-	-	-	-	8.61
2019	9	196	14	1	3.54	21.75	-	-	-	-	-	-	-	-	1	-	-	-	8.53
2019	10	50	308	1	3.54	21.83	-	-	-	-	-	-	-	-	-	1	-	-	8.45
2019	11	-	749	1	3.54	21.92	-	-	-	-	-	-	-	-	-	-	1	-	8.42
2019	12	-	829	1	3.54	22.00	-	-	-	-	-	-	-	-	-	-	-	1	8.52
2020	1	-	1,039	1	3.54	22.08	1	-	-	-	-	-	-	-	-	-	-	-	8.54
2020	2	-	1,013	1	3.54	22.17	-	1	-	-	-	-	-	-	-	-	-	-	8.49
2020	3	0	810	1	3.54	22.25	-	-	1	-	-	-	-	-	-	-	-	-	8.49
2020	4	3	575	1	3.54	22.33	-	-	-	1	-	-	-	-	-	-	-	-	8.42
2020	5	15	334	1	3.54	22.42	-	-	-	-	1	-	-	-	-	-	-	-	8.39
2020	6	98	94	1	3.55	22.50	-	-	-	-	-	1	-	-	-	-	-	-	8.48
2020	7	321	4	1	3.55	22.58	-	-	-	-	-	-	1	-	-	-	-	-	8.59
2020	8	418	1	1	3.55	22.67	-	-	-	-	-	-	-	1	-	-	-	-	8.65
2020	9	270	22	1	3.55	22.75	-	-	-	-	-	-	-	-	1	-	-	-	8.56
2020	10	53	211	1	3.55	22.83	-	-	-	-	-	-	-	-	-	1	-	-	8.44
2020	11	5	502	1	3.55	22.92	-	-	-	-	-	-	-	-	-	-	1	-	8.40
2020	12	0	848	1	3.55	23.00	-	-	-	-	-	-	-	-	-	-	-	1	8.52
2021	1	-	1,039	1	3.55	23.08	1	-	-	-	-	-	-	-	-	-	-	-	8.54
2021	2	-	1,013	1	3.55	23.17	-	1	-	-	-	-	-	-	-	-	-	-	8.49
2021	3	0	810	1	3.55	23.25	-	-	1	-	-	-	-	-	-	-	-	-	8.48
2021	4	3	575	1	3.55	23.33	-	-	-	1	-	-	-	-	-	-	-	-	8.42
2021	5	15	334	1	3.56	23.42	-	-	-	-	1	-	-	-	-	-	-	-	8.39
2021	6	98	94	1	3.56	23.50	-	-	-	-	-	1	-	-	-	-	-	-	8.48
2021	7	321	4	1	3.56	23.58	-	-	-	-	-	-	1	-	-	-	-	-	8.59
2021	8	418	1	1	3.56	23.67	-	-	-	-	-	-	-	1	-	-	-	-	8.65
2021	9	270	22	1	3.56	23.75	-	-	-	-	-	-	-	-	1	-	-	-	8.56
2021	10	53	211	1	3.56	23.83	-	-	-	-	-	-	-	-	-	1	-	-	8.44
2021	11	5	502	1	3.56	23.92	-	-	-	-	-	-	-	-	-	-	1	-	8.40
2021	12	0	848	1	3.56	24.00	-	-	-	-	-	-	-	-	-	-	-	1	8.52

2022	1	-	1,039	1	3.56	24.08	1	-	-	-	-	-	-	-	-	-	-	-	8.54
2022	2	-	1,013	1	3.56	24.17	-	1	-	-	-	-	-	-	-	-	-	-	8.49
2022	3	0	810	1	3.57	24.25	-	-	1	-	-	-	-	-	-	-	-	-	8.48
2022	4	3	575	1	3.57	24.33	-	-	-	1	-	-	-	-	-	-	-	-	8.42
2022	5	15	334	1	3.57	24.42	-	-	-	-	1	-	-	-	-	-	-	-	8.39
2022	6	98	94	1	3.57	24.50	-	-	-	-	-	1	-	-	-	-	-	-	8.48
2022	7	321	4	1	3.57	24.58	-	-	-	-	-	-	1	-	-	-	-	-	8.59
2022	8	418	1	1	3.57	24.67	-	-	-	-	-	-	-	1	-	-	-	-	8.65
2022	9	270	22	1	3.57	24.75	-	-	-	-	-	-	-	-	1	-	-	-	8.56
2022	10	53	211	1	3.57	24.83	-	-	-	-	-	-	-	-	-	1	-	-	8.44
2022	11	5	502	1	3.57	24.92	-	-	-	-	-	-	-	-	-	-	1	-	8.40
2022	12	0	848	1	3.57	25.00	-	-	-	-	-	-	-	-	-	-	-	1	8.52
2023	1	-	1,039	1	3.57	25.08	1	-	-	-	-	-	-	-	-	-	-	-	8.54
2023	2	-	1,013	1	3.58	25.17	-	1	-	-	-	-	-	-	-	-	-	-	8.49
2023	3	0	810	1	3.58	25.25	-	-	1	-	-	-	-	-	-	-	-	-	8.48
2023	4	3	575	1	3.58	25.33	-	-	-	1	-	-	-	-	-	-	-	-	8.42
2023	5	15	334	1	3.58	25.42	-	-	-	-	1	-	-	-	-	-	-	-	8.39
2023	6	98	94	1	3.58	25.50	-	-	-	-	-	1	-	-	-	-	-	-	8.47
2023	7	321	4	1	3.58	25.58	-	-	-	-	-	-	1	-	-	-	-	-	8.59
2023	8	418	1	1	3.58	25.67	-	-	-	-	-	-	-	1	-	-	-	-	8.64
2023	9	270	22	1	3.58	25.75	-	-	-	-	-	-	-	-	1	-	-	-	8.55
2023	10	53	211	1	3.58	25.83	-	-	-	-	-	-	-	-	-	1	-	-	8.44
2023	11	5	502	1	3.58	25.92	-	-	-	-	-	-	-	-	-	-	1	-	8.40
2023	12	0	848	1	3.58	26.00	-	-	-	-	-	-	-	-	-	-	-	1	8.52
2024	1	-	1,039	1	3.58	26.08	1	-	-	-	-	-	-	-	-	-	-	-	8.54
2024	2	-	1,013	1	3.59	26.17	-	1	-	-	-	-	-	-	-	-	-	-	8.49
2024	3	0	810	1	3.59	26.25	-	-	1	-	-	-	-	-	-	-	-	-	8.48
2024	4	3	575	1	3.59	26.33	-	-	-	1	-	-	-	-	-	-	-	-	8.42
2024	5	15	334	1	3.59	26.42	-	-	-	-	1	-	-	-	-	-	-	-	8.39
2024	6	98	94	1	3.59	26.50	-	-	-	-	-	1	-	-	-	-	-	-	8.47
2024	7	321	4	1	3.59	26.58	-	-	-	-	-	-	1	-	-	-	-	-	8.59
2024	8	418	1	1	3.59	26.67	-	-	-	-	-	-	-	1	-	-	-	-	8.64
2024	9	270	22	1	3.59	26.75	-	-	-	-	-	-	-	-	1	-	-	-	8.55
2024	10	53	211	1	3.59	26.83	-	-	-	-	-	-	-	-	-	1	-	-	8.44
2024	11	5	502	1	3.59	26.92	-	-	-	-	-	-	-	-	-	-	1	-	8.39

2024	12	0	848	1	3.59	27.00	-	-	-	-	-	-	-	-	-	-	-	1	8.52
2025	1	-	1,039	1	3.59	27.08	1	-	-	-	-	-	-	-	-	-	-	-	8.54
2025	2	-	1,013	1	3.60	27.17	-	1	-	-	-	-	-	-	-	-	-	-	8.48
2025	3	0	810	1	3.60	27.25	-	-	1	-	-	-	-	-	-	-	-	-	8.48
2025	4	3	575	1	3.60	27.33	-	-	-	1	-	-	-	-	-	-	-	-	8.41
2025	5	15	334	1	3.60	27.42	-	-	-	-	1	-	-	-	-	-	-	-	8.39
2025	6	98	94	1	3.60	27.50	-	-	-	-	-	1	-	-	-	-	-	-	8.47
2025	7	321	4	1	3.60	27.58	-	-	-	-	-	-	1	-	-	-	-	-	8.58
2025	8	418	1	1	3.60	27.67	-	-	-	-	-	-	-	1	-	-	-	-	8.64
2025	9	270	22	1	3.60	27.75	-	-	-	-	-	-	-	-	1	-	-	-	8.55
2025	10	53	211	1	3.60	27.83	-	-	-	-	-	-	-	-	-	1	-	-	8.44
2025	11	5	502	1	3.60	27.92	-	-	-	-	-	-	-	-	-	-	1	-	8.39
2025	12	0	848	1	3.60	28.00	-	-	-	-	-	-	-	-	-	-	-	1	8.52
2026	1	-	1,039	1	3.60	28.08	1	-	-	-	-	-	-	-	-	-	-	-	8.54
2026	2	-	1,013	1	3.61	28.17	-	1	-	-	-	-	-	-	-	-	-	-	8.48
2026	3	0	810	1	3.61	28.25	-	-	1	-	-	-	-	-	-	-	-	-	8.48
2026	4	3	575	1	3.61	28.33	-	-	-	1	-	-	-	-	-	-	-	-	8.41
2026	5	15	334	1	3.61	28.42	-	-	-	-	1	-	-	-	-	-	-	-	8.38
2026	6	98	94	1	3.61	28.50	-	-	-	-	-	1	-	-	-	-	-	-	8.47
2026	7	321	4	1	3.61	28.58	-	-	-	-	-	-	1	-	-	-	-	-	8.58
2026	8	418	1	1	3.61	28.67	-	-	-	-	-	-	-	1	-	-	-	-	8.64
2026	9	270	22	1	3.61	28.75	-	-	-	-	-	-	-	-	1	-	-	-	8.55
2026	10	53	211	1	3.61	28.83	-	-	-	-	-	-	-	-	-	1	-	-	8.44
2026	11	5	502	1	3.61	28.92	-	-	-	-	-	-	-	-	-	-	1	-	8.39
2026	12	0	848	1	3.61	29.00	-	-	-	-	-	-	-	-	-	-	-	1	8.51
2027	1	-	1,039	1	3.62	29.08	1	-	-	-	-	-	-	-	-	-	-	-	8.54
2027	2	-	1,013	1	3.62	29.17	-	1	-	-	-	-	-	-	-	-	-	-	8.48
2027	3	0	810	1	3.62	29.25	-	-	1	-	-	-	-	-	-	-	-	-	8.48
2027	4	3	575	1	3.62	29.33	-	-	-	1	-	-	-	-	-	-	-	-	8.41
2027	5	15	334	1	3.62	29.42	-	-	-	-	1	-	-	-	-	-	-	-	8.38
2027	6	98	94	1	3.62	29.50	-	-	-	-	-	1	-	-	-	-	-	-	8.47
2027	7	321	4	1	3.62	29.58	-	-	-	-	-	-	1	-	-	-	-	-	8.58
2027	8	418	1	1	3.62	29.67	-	-	-	-	-	-	-	1	-	-	-	-	8.64
2027	9	270	22	1	3.62	29.75	-	-	-	-	-	-	-	-	1	-	-	-	8.55
2027	10	53	211	1	3.62	29.83	-	-	-	-	-	-	-	-	-	1	-	-	8.44

2027	11	5	502	1	3.62	29.92	-	-	-	-	-	-	-	-	-	-	1	-	8.39
2027	12	0	848	1	3.62	30.00	-	-	-	-	-	-	-	-	-	-	-	1	8.51
2028	1	-	1,039	1	3.62	30.08	1	-	-	-	-	-	-	-	-	-	-	-	8.54
2028	2	-	1,013	1	3.63	30.17	-	1	-	-	-	-	-	-	-	-	-	-	8.48
2028	3	0	810	1	3.63	30.25	-	-	1	-	-	-	-	-	-	-	-	-	8.48
2028	4	3	575	1	3.63	30.33	-	-	-	1	-	-	-	-	-	-	-	-	8.41
2028	5	15	334	1	3.63	30.42	-	-	-	-	1	-	-	-	-	-	-	-	8.38
2028	6	98	94	1	3.63	30.50	-	-	-	-	-	1	-	-	-	-	-	-	8.47
2028	7	321	4	1	3.63	30.58	-	-	-	-	-	-	1	-	-	-	-	-	8.58
2028	8	418	1	1	3.63	30.67	-	-	-	-	-	-	-	1	-	-	-	-	8.64
2028	9	270	22	1	3.63	30.75	-	-	-	-	-	-	-	-	1	-	-	-	8.55
2028	10	53	211	1	3.63	30.83	-	-	-	-	-	-	-	-	-	1	-	-	8.43
2028	11	5	502	1	3.63	30.92	-	-	-	-	-	-	-	-	-	-	1	-	8.39
2028	12	0	848	1	3.63	31.00	-	-	-	-	-	-	-	-	-	-	-	1	8.51
2029	1	-	1,039	1	3.63	31.08	1	-	-	-	-	-	-	-	-	-	-	-	8.53
2029	2	-	1,013	1	3.64	31.17	-	1	-	-	-	-	-	-	-	-	-	-	8.48
2029	3	0	810	1	3.64	31.25	-	-	1	-	-	-	-	-	-	-	-	-	8.47
2029	4	3	575	1	3.64	31.33	-	-	-	1	-	-	-	-	-	-	-	-	8.41
2029	5	15	334	1	3.64	31.42	-	-	-	-	1	-	-	-	-	-	-	-	8.38
2029	6	98	94	1	3.64	31.50	-	-	-	-	-	1	-	-	-	-	-	-	8.47
2029	7	321	4	1	3.64	31.58	-	-	-	-	-	-	1	-	-	-	-	-	8.58
2029	8	418	1	1	3.64	31.67	-	-	-	-	-	-	-	1	-	-	-	-	8.64
2029	9	270	22	1	3.64	31.75	-	-	-	-	-	-	-	-	1	-	-	-	8.55
2029	10	53	211	1	3.64	31.83	-	-	-	-	-	-	-	-	-	1	-	-	8.43
2029	11	5	502	1	3.64	31.92	-	-	-	-	-	-	-	-	-	-	1	-	8.39
2029	12	0	848	1	3.64	32.00	-	-	-	-	-	-	-	-	-	-	-	1	8.51
2030	1	-	1,039	1	3.64	32.08	1	-	-	-	-	-	-	-	-	-	-	-	8.53
2030	2	-	1,013	1	3.64	32.17	-	1	-	-	-	-	-	-	-	-	-	-	8.48
2030	3	0	810	1	3.65	32.25	-	-	1	-	-	-	-	-	-	-	-	-	8.47
2030	4	3	575	1	3.65	32.33	-	-	-	1	-	-	-	-	-	-	-	-	8.41
2030	5	15	334	1	3.65	32.42	-	-	-	-	1	-	-	-	-	-	-	-	8.38
2030	6	98	94	1	3.65	32.50	-	-	-	-	-	1	-	-	-	-	-	-	8.46
2030	7	321	4	1	3.65	32.58	-	-	-	-	-	-	1	-	-	-	-	-	8.58
2030	8	418	1	1	3.65	32.67	-	-	-	-	-	-	-	1	-	-	-	-	8.63
2030	9	270	22	1	3.65	32.75	-	-	-	-	-	-	-	-	1	-	-	-	8.54

2030	10	53	211	1	3.65	32.83	-	-	-	-	-	-	-	-	-	1	-	-	8.43
2030	11	5	502	1	3.65	32.92	-	-	-	-	-	-	-	-	-	-	1	-	8.38
2030	12	0	848	1	3.65	33.00	-	-	-	-	-	-	-	-	-	-	-	1	8.51
2031	1	-	1,039	1	3.65	33.08	1	-	-	-	-	-	-	-	-	-	-	-	8.53
2031	2	-	1,013	1	3.65	33.17	-	1	-	-	-	-	-	-	-	-	-	-	8.48
2031	3	0	810	1	3.65	33.25	-	-	1	-	-	-	-	-	-	-	-	-	8.47
2031	4	3	575	1	3.65	33.33	-	-	-	1	-	-	-	-	-	-	-	-	8.40
2031	5	15	334	1	3.66	33.42	-	-	-	-	1	-	-	-	-	-	-	-	8.38
2031	6	98	94	1	3.66	33.50	-	-	-	-	-	1	-	-	-	-	-	-	8.46
2031	7	321	4	1	3.66	33.58	-	-	-	-	-	-	1	-	-	-	-	-	8.57
2031	8	418	1	1	3.66	33.67	-	-	-	-	-	-	-	1	-	-	-	-	8.63
2031	9	270	22	1	3.66	33.75	-	-	-	-	-	-	-	-	1	-	-	-	8.54
2031	10	53	211	1	3.66	33.83	-	-	-	-	-	-	-	-	-	1	-	-	8.43
2031	11	5	502	1	3.66	33.92	-	-	-	-	-	-	-	-	-	-	1	-	8.38
2031	12	0	848	1	3.66	34.00	-	-	-	-	-	-	-	-	-	-	-	1	8.51
2032	1	-	1,039	1	3.66	34.08	1	-	-	-	-	-	-	-	-	-	-	-	8.53
2032	2	-	1,013	1	3.66	34.17	-	1	-	-	-	-	-	-	-	-	-	-	8.47
2032	3	0	810	1	3.66	34.25	-	-	1	-	-	-	-	-	-	-	-	-	8.47
2032	4	3	575	1	3.66	34.33	-	-	-	1	-	-	-	-	-	-	-	-	8.40
2032	5	15	334	1	3.66	34.42	-	-	-	-	1	-	-	-	-	-	-	-	8.37
2032	6	98	94	1	3.66	34.50	-	-	-	-	-	1	-	-	-	-	-	-	8.46
2032	7	321	4	1	3.67	34.58	-	-	-	-	-	-	1	-	-	-	-	-	8.57
2032	8	418	1	1	3.67	34.67	-	-	-	-	-	-	-	1	-	-	-	-	8.63
2032	9	270	22	1	3.67	34.75	-	-	-	-	-	-	-	-	1	-	-	-	8.54
2032	10	53	211	1	3.67	34.83	-	-	-	-	-	-	-	-	-	1	-	-	8.43
2032	11	5	502	1	3.67	34.92	-	-	-	-	-	-	-	-	-	-	1	-	8.38
2032	12	0	848	1	3.67	35.00	-	-	-	-	-	-	-	-	-	-	-	1	8.50
2033	1	-	1,039	1	3.67	35.08	1	-	-	-	-	-	-	-	-	-	-	-	8.53
2033	2	-	1,013	1	3.67	35.17	-	1	-	-	-	-	-	-	-	-	-	-	8.47
2033	3	0	810	1	3.67	35.25	-	-	1	-	-	-	-	-	-	-	-	-	8.47
2033	4	3	575	1	3.67	35.33	-	-	-	1	-	-	-	-	-	-	-	-	8.40
2033	5	15	334	1	3.67	35.42	-	-	-	-	1	-	-	-	-	-	-	-	8.37
2033	6	98	94	1	3.67	35.50	-	-	-	-	-	1	-	-	-	-	-	-	8.46
2033	7	321	4	1	3.67	35.58	-	-	-	-	-	-	1	-	-	-	-	-	8.57
2033	8	418	1	1	3.67	35.67	-	-	-	-	-	-	-	1	-	-	-	-	8.63

2033	9	270	22	1	3.67	35.75	-	-	-	-	-	-	-	-	1	-	-	-	8.54
2033	10	53	211	1	3.68	35.83	-	-	-	-	-	-	-	-	-	1	-	-	8.42
2033	11	5	502	1	3.68	35.92	-	-	-	-	-	-	-	-	-	-	1	-	8.38
2033	12	0	848	1	3.68	36.00	-	-	-	-	-	-	-	-	-	-	-	1	8.50
2034	1	-	1,039	1	3.68	36.08	1	-	-	-	-	-	-	-	-	-	-	-	8.52
2034	2	-	1,013	1	3.68	36.17	-	1	-	-	-	-	-	-	-	-	-	-	8.47
2034	3	0	810	1	3.68	36.25	-	-	1	-	-	-	-	-	-	-	-	-	8.46
2034	4	3	575	1	3.68	36.33	-	-	-	1	-	-	-	-	-	-	-	-	8.40
2034	5	15	334	1	3.68	36.42	-	-	-	-	1	-	-	-	-	-	-	-	8.37
2034	6	98	94	1	3.68	36.50	-	-	-	-	-	1	-	-	-	-	-	-	8.46
2034	7	321	4	1	3.68	36.58	-	-	-	-	-	-	1	-	-	-	-	-	8.57
2034	8	418	1	1	3.68	36.67	-	-	-	-	-	-	-	1	-	-	-	-	8.63
2034	9	270	22	1	3.68	36.75	-	-	-	-	-	-	-	-	1	-	-	-	8.53
2034	10	53	211	1	3.68	36.83	-	-	-	-	-	-	-	-	-	1	-	-	8.42
2034	11	5	502	1	3.68	36.92	-	-	-	-	-	-	-	-	-	-	1	-	8.38
2034	12	0	848	1	3.68	37.00	-	-	-	-	-	-	-	-	-	-	-	1	8.50
2035	1	-	1,039	1	3.69	37.08	1	-	-	-	-	-	-	-	-	-	-	-	8.52
2035	2	-	1,013	1	3.69	37.17	-	1	-	-	-	-	-	-	-	-	-	-	8.47
2035	3	0	810	1	3.69	37.25	-	-	1	-	-	-	-	-	-	-	-	-	8.46
2035	4	3	575	1	3.69	37.33	-	-	-	1	-	-	-	-	-	-	-	-	8.40
2035	5	15	334	1	3.69	37.42	-	-	-	-	1	-	-	-	-	-	-	-	8.37
2035	6	98	94	1	3.69	37.50	-	-	-	-	-	1	-	-	-	-	-	-	8.45
2035	7	321	4	1	3.69	37.58	-	-	-	-	-	-	1	-	-	-	-	-	8.56
2035	8	418	1	1	3.69	37.67	-	-	-	-	-	-	-	1	-	-	-	-	8.62
2035	9	270	22	1	3.69	37.75	-	-	-	-	-	-	-	-	1	-	-	-	8.53
2035	10	53	211	1	3.69	37.83	-	-	-	-	-	-	-	-	-	1	-	-	8.42
2035	11	5	502	1	3.69	37.92	-	-	-	-	-	-	-	-	-	-	1	-	8.37
2035	12	0	848	1	3.69	38.00	-	-	-	-	-	-	-	-	-	-	-	1	8.50
2036	1	-	1,039	1	3.69	38.08	1	-	-	-	-	-	-	-	-	-	-	-	8.52
2036	2	-	1,013	1	3.69	38.17	-	1	-	-	-	-	-	-	-	-	-	-	8.46
2036	3	0	810	1	3.69	38.25	-	-	1	-	-	-	-	-	-	-	-	-	8.46
2036	4	3	575	1	3.69	38.33	-	-	-	1	-	-	-	-	-	-	-	-	8.39
2036	5	15	334	1	3.70	38.42	-	-	-	-	1	-	-	-	-	-	-	-	8.36
2036	6	98	94	1	3.70	38.50	-	-	-	-	-	1	-	-	-	-	-	-	8.45
2036	7	321	4	1	3.70	38.58	-	-	-	-	-	-	1	-	-	-	-	-	8.56

2036	8	418	1	1	3.70	38.67	-	-	-	-	-	-	-	1	-	-	-	-	8.62
2036	9	270	22	1	3.70	38.75	-	-	-	-	-	-	-	-	1	-	-	-	8.53
2036	10	53	211	1	3.70	38.83	-	-	-	-	-	-	-	-	-	1	-	-	8.42
2036	11	5	502	1	3.70	38.92	-	-	-	-	-	-	-	-	-	-	1	-	8.37
2036	12	0	848	1	3.70	39.00	-	-	-	-	-	-	-	-	-	-	-	1	8.49
2037	1	-	1,039	1	3.70	39.08	1	-	-	-	-	-	-	-	-	-	-	-	8.52
2037	2	-	1,013	1	3.70	39.17	-	1	-	-	-	-	-	-	-	-	-	-	8.46
2037	3	0	810	1	3.70	39.25	-	-	1	-	-	-	-	-	-	-	-	-	8.46
2037	4	3	575	1	3.70	39.33	-	-	-	1	-	-	-	-	-	-	-	-	8.39
2037	5	15	334	1	3.70	39.42	-	-	-	-	1	-	-	-	-	-	-	-	8.36
2037	6	98	94	1	3.70	39.50	-	-	-	-	-	1	-	-	-	-	-	-	8.45
2037	7	321	4	1	3.70	39.58	-	-	-	-	-	-	1	-	-	-	-	-	8.56
2037	8	418	1	1	3.70	39.67	-	-	-	-	-	-	-	1	-	-	-	-	8.62
2037	9	270	22	1	3.70	39.75	-	-	-	-	-	-	-	-	1	-	-	-	8.53
2037	10	53	211	1	3.70	39.83	-	-	-	-	-	-	-	-	-	1	-	-	8.41
2037	11	5	502	1	3.71	39.92	-	-	-	-	-	-	-	-	-	-	1	-	8.37
2037	12	0	848	1	3.71	40.00	-	-	-	-	-	-	-	-	-	-	-	1	8.49
2038	1	-	1,039	1	3.71	40.08	1	-	-	-	-	-	-	-	-	-	-	-	8.51
2038	2	-	1,013	1	3.71	40.17	-	1	-	-	-	-	-	-	-	-	-	-	8.46
2038	3	0	810	1	3.71	40.25	-	-	1	-	-	-	-	-	-	-	-	-	8.45
2038	4	3	575	1	3.71	40.33	-	-	-	1	-	-	-	-	-	-	-	-	8.39
2038	5	15	334	1	3.71	40.42	-	-	-	-	1	-	-	-	-	-	-	-	8.36
2038	6	98	94	1	3.71	40.50	-	-	-	-	-	1	-	-	-	-	-	-	8.44
2038	7	321	4	1	3.71	40.58	-	-	-	-	-	-	1	-	-	-	-	-	8.56
2038	8	418	1	1	3.71	40.67	-	-	-	-	-	-	-	1	-	-	-	-	8.61
2038	9	270	22	1	3.71	40.75	-	-	-	-	-	-	-	-	1	-	-	-	8.52
2038	10	53	211	1	3.71	40.83	-	-	-	-	-	-	-	-	-	1	-	-	8.41
2038	11	5	502	1	3.71	40.92	-	-	-	-	-	-	-	-	-	-	1	-	8.36
2038	12	0	848	1	3.71	41.00	-	-	-	-	-	-	-	-	-	-	-	1	8.49
2039	1	-	1,039	1	3.71	41.08	1	-	-	-	-	-	-	-	-	-	-	-	8.51
2039	2	-	1,013	1	3.71	41.17	-	1	-	-	-	-	-	-	-	-	-	-	8.45
2039	3	0	810	1	3.71	41.25	-	-	1	-	-	-	-	-	-	-	-	-	8.45
2039	4	3	575	1	3.72	41.33	-	-	-	1	-	-	-	-	-	-	-	-	8.38
2039	5	15	334	1	3.72	41.42	-	-	-	-	1	-	-	-	-	-	-	-	8.35
2039	6	98	94	1	3.72	41.50	-	-	-	-	-	1	-	-	-	-	-	-	8.44

2039	7	321	4	1	3.72	41.58	-	-	-	-	-	-	1	-	-	-	-	-	8.55
2039	8	418	1	1	3.72	41.67	-	-	-	-	-	-	-	1	-	-	-	-	8.61
2039	9	270	22	1	3.72	41.75	-	-	-	-	-	-	-	-	1	-	-	-	8.52
2039	10	53	211	1	3.72	41.83	-	-	-	-	-	-	-	-	-	1	-	-	8.41
2039	11	5	502	1	3.72	41.92	-	-	-	-	-	-	-	-	-	-	1	-	8.36
2039	12	0	848	1	3.72	42.00	-	-	-	-	-	-	-	-	-	-	-	1	8.48
2040	1	-	1,039	1	3.72	42.08	1	-	-	-	-	-	-	-	-	-	-	-	8.51
2040	2	-	1,013	1	3.72	42.17	-	1	-	-	-	-	-	-	-	-	-	-	8.45
2040	3	0	810	1	3.72	42.25	-	-	1	-	-	-	-	-	-	-	-	-	8.45
2040	4	3	575	1	3.72	42.33	-	-	-	1	-	-	-	-	-	-	-	-	8.38
2040	5	15	334	1	3.72	42.42	-	-	-	-	1	-	-	-	-	-	-	-	8.35
2040	6	98	94	1	3.72	42.50	-	-	-	-	-	1	-	-	-	-	-	-	8.44
2040	7	321	4	1	3.72	42.58	-	-	-	-	-	-	1	-	-	-	-	-	8.55
2040	8	418	1	1	3.72	42.67	-	-	-	-	-	-	-	1	-	-	-	-	8.61
2040	9	270	22	1	3.72	42.75	-	-	-	-	-	-	-	-	1	-	-	-	8.52
2040	10	53	211	1	3.72	42.83	-	-	-	-	-	-	-	-	-	1	-	-	8.40
2040	11	5	502	1	3.73	42.92	-	-	-	-	-	-	-	-	-	-	1	-	8.36
2040	12	0	848	1	3.73	43.00	-	-	-	-	-	-	-	-	-	-	-	1	8.48

Schedule C-15. Black Hills Power: Variable Statistical Values for Commercial Use Per Customer Model

Black Hills Power **Confidential Appendix C**

Black Hills Power: Variable Statistical Values for Commercial Use Per Customer Model **Schedule C-15**

Variable	Coefficient	Standard Error	P Value	R2 = 0.9122
cdd60	0.000	0.000	0.000	
hdd60	0.000	0.000	0.000	
class_shift	0.061	0.008	0.000	
lntotemp12	0.476	0.236	0.045	
trend	-0.006	0.003	0.029	
m2	-0.052	0.012	0.001	
m3	-0.039	0.012	0.000	
m4	-0.085	0.014	0.000	
m5	-0.098	0.017	0.257	
m6	-0.024	0.021	0.837	
m7	0.005	0.027	0.408	
m8	0.025	0.030	0.769	
m9	-0.007	0.025	0.011	
m10	-0.048	0.019	0.000	
m11	-0.100	0.015	0.651	
m12	-0.006	0.012	0.111	
_cons	6.844	0.778	0.000	

Schedule C-16. Black Hills Power: Historical and Forecasted Variable Values for Commercial Customer Model

Black Hills Power **Confidential Appendix C**

Black Hills Power: Historical and Forecasted Variable Values for Commercial Customer Model **Schedule C-16**

Year	Month	lntotemp12	lntotemp_shift	class_shift	m1	m2	m3	m4	m5	m6	m7	m8	m9	m10	m11	m12	ln(custs)
1999	1	3.29	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.20
1999	2	3.29	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.19
1999	3	3.29	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.20
1999	4	3.30	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.21
1999	5	3.30	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.22
1999	6	3.30	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.23
1999	7	3.30	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.23
1999	8	3.30	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.24
1999	9	3.30	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.23
1999	10	3.30	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.23
1999	11	3.31	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.23
1999	12	3.31	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.22
2000	1	3.31	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.23
2000	2	3.31	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.22
2000	3	3.32	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.23
2000	4	3.32	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.24
2000	5	3.32	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.25
2000	6	3.32	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.26
2000	7	3.32	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.27
2000	8	3.33	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.28
2000	9	3.33	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.27
2000	10	3.33	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.27
2000	11	3.33	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.27
2000	12	3.34	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.26
2001	1	3.34	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.27
2001	2	3.34	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.26
2001	3	3.34	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.27
2001	4	3.34	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.27
2001	5	3.34	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.28
2001	6	3.34	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.29
2001	7	3.34	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.29

2001	8	3.34	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.30
2001	9	3.34	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.30
2001	10	3.34	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.29
2001	11	3.35	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.28
2001	12	3.35	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.28
2002	1	3.35	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.28
2002	2	3.35	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.28
2002	3	3.35	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.28
2002	4	3.35	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.29
2002	5	3.35	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.30
2002	6	3.35	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.31
2002	7	3.35	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.31
2002	8	3.36	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.32
2002	9	3.36	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.31
2002	10	3.36	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.31
2002	11	3.36	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.31
2002	12	3.36	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.30
2003	1	3.36	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.30
2003	2	3.36	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.30
2003	3	3.36	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.30
2003	4	3.36	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.31
2003	5	3.36	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.32
2003	6	3.36	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.32
2003	7	3.36	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.33
2003	8	3.36	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.33
2003	9	3.37	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.33
2003	10	3.37	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.32
2003	11	3.37	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.32
2003	12	3.37	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.31
2004	1	3.37	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.31
2004	2	3.37	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.31
2004	3	3.37	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.31
2004	4	3.37	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.32
2004	5	3.37	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.33
2004	6	3.37	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.33

2004	7	3.37	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.34
2004	8	3.37	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.35
2004	9	3.38	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.34
2004	10	3.38	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.34
2004	11	3.38	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.33
2004	12	3.38	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.33
2005	1	3.38	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.33
2005	2	3.38	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.33
2005	3	3.38	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.33
2005	4	3.38	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.34
2005	5	3.38	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.35
2005	6	3.39	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.35
2005	7	3.39	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.36
2005	8	3.39	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.37
2005	9	3.39	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.36
2005	10	3.39	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.36
2005	11	3.39	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.35
2005	12	3.39	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.35
2006	1	3.39	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.35
2006	2	3.40	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.35
2006	3	3.40	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.35
2006	4	3.40	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.36
2006	5	3.40	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.37
2006	6	3.40	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.38
2006	7	3.40	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.38
2006	8	3.40	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.39
2006	9	3.40	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.39
2006	10	3.41	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.38
2006	11	3.41	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.38
2006	12	3.41	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.37
2007	1	3.41	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.37
2007	2	3.41	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.37
2007	3	3.41	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.38
2007	4	3.42	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.39
2007	5	3.42	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.40

2007	6	3.42	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.41
2007	7	3.42	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.41
2007	8	3.42	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.42
2007	9	3.43	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.42
2007	10	3.43	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.41
2007	11	3.43	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.41
2007	12	3.43	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.40
2008	1	3.43	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.41
2008	2	3.44	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.41
2008	3	3.44	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.41
2008	4	3.44	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.42
2008	5	3.44	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.43
2008	6	3.44	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.44
2008	7	3.44	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.44
2008	8	3.44	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.45
2008	9	3.45	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.45
2008	10	3.45	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.44
2008	11	3.45	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.44
2008	12	3.45	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.43
2009	1	3.45	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.43
2009	2	3.45	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.43
2009	3	3.45	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.43
2009	4	3.45	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.44
2009	5	3.45	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.44
2009	6	3.45	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.45
2009	7	3.45	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.45
2009	8	3.45	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.46
2009	9	3.45	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.45
2009	10	3.45	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.44
2009	11	3.45	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.44
2009	12	3.45	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.43
2010	1	3.44	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.42
2010	2	3.44	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.42
2010	3	3.44	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.42
2010	4	3.44	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.43

2010	5	3.44	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.44
2010	6	3.44	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.44
2010	7	3.44	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.44
2010	8	3.44	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.45
2010	9	3.44	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.44
2010	10	3.44	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.44
2010	11	3.44	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.43
2010	12	3.44	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.42
2011	1	3.44	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.42
2011	2	3.45	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.42
2011	3	3.45	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.42
2011	4	3.45	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.43
2011	5	3.45	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.44
2011	6	3.45	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.45
2011	7	3.45	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.45
2011	8	3.45	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.46
2011	9	3.45	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.45
2011	10	3.45	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.45
2011	11	3.45	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.44
2011	12	3.45	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.44
2012	1	3.45	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.44
2012	2	3.46	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.44
2012	3	3.46	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.44
2012	4	3.46	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.45
2012	5	3.46	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.46
2012	6	3.46	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.46
2012	7	3.46	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.47
2012	8	3.46	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.48
2012	9	3.46	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.47
2012	10	3.46	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.46
2012	11	3.46	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.46
2012	12	3.46	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.45
2013	1	3.47	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.45
2013	2	3.47	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.45
2013	3	3.47	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.46

2013	4	3.47	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.46
2013	5	3.47	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.47
2013	6	3.47	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	9.48
2013	7	3.47	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	9.48
2013	8	3.47	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	9.49
2013	9	3.47	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	9.49
2013	10	3.47	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	9.48
2013	11	3.47	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	9.48
2013	12	3.48	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	9.47
2014	1	3.48	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	9.47
2014	2	3.48	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	9.47
2014	3	3.48	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	9.47
2014	4	3.48	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	9.48
2014	5	3.48	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	9.49
2014	6	3.48	3.48	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.49
2014	7	3.48	3.48	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.49
2014	8	3.48	3.48	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.50
2014	9	3.49	3.49	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.49
2014	10	3.49	3.49	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.49
2014	11	3.49	3.49	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.48
2014	12	3.49	3.49	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.47
2015	1	3.49	3.49	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.47
2015	2	3.49	3.49	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.47
2015	3	3.49	3.49	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.47
2015	4	3.49	3.49	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.48
2015	5	3.49	3.49	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.49
2015	6	3.49	3.49	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.49
2015	7	3.49	3.49	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.50
2015	8	3.49	3.49	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.50
2015	9	3.49	3.49	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.50
2015	10	3.49	3.49	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.49
2015	11	3.49	3.49	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.48
2015	12	3.49	3.49	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.47
2016	1	3.49	3.49	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.47
2016	2	3.49	3.49	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.47

2016	3	3.49	3.49	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.47
2016	4	3.49	3.49	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.48
2016	5	3.50	3.50	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.49
2016	6	3.50	3.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.49
2016	7	3.50	3.50	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.50
2016	8	3.50	3.50	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.50
2016	9	3.50	3.50	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.50
2016	10	3.50	3.50	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.49
2016	11	3.50	3.50	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.48
2016	12	3.50	3.50	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.48
2017	1	3.50	3.50	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.48
2017	2	3.50	3.50	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.47
2017	3	3.50	3.50	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.48
2017	4	3.51	3.51	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.48
2017	5	3.51	3.51	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.49
2017	6	3.51	3.51	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.50
2017	7	3.51	3.51	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.50
2017	8	3.51	3.51	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.51
2017	9	3.51	3.51	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.50
2017	10	3.51	3.51	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.49
2017	11	3.51	3.51	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.49
2017	12	3.51	3.51	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.48
2018	1	3.51	3.51	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.48
2018	2	3.52	3.52	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.47
2018	3	3.52	3.52	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.48
2018	4	3.52	3.52	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.48
2018	5	3.52	3.52	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.49
2018	6	3.52	3.52	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.50
2018	7	3.52	3.52	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.50
2018	8	3.52	3.52	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.51
2018	9	3.52	3.52	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.50
2018	10	3.52	3.52	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.50
2018	11	3.53	3.53	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.49
2018	12	3.53	3.53	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.48
2019	1	3.53	3.53	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.48

2019	2	3.53	3.53	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.48
2019	3	3.53	3.53	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.48
2019	4	3.53	3.53	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.49
2019	5	3.53	3.53	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.49
2019	6	3.53	3.53	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.50
2019	7	3.53	3.53	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.50
2019	8	3.54	3.54	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.51
2019	9	3.54	3.54	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.50
2019	10	3.54	3.54	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.50
2019	11	3.54	3.54	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.49
2019	12	3.54	3.54	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.48
2020	1	3.54	3.54	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.48
2020	2	3.54	3.54	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.48
2020	3	3.54	3.54	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.48
2020	4	3.54	3.54	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.49
2020	5	3.54	3.54	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.50
2020	6	3.55	3.55	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.50
2020	7	3.55	3.55	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.51
2020	8	3.55	3.55	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.51
2020	9	3.55	3.55	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.51
2020	10	3.55	3.55	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.50
2020	11	3.55	3.55	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.49
2020	12	3.55	3.55	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.49
2021	1	3.55	3.55	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.49
2021	2	3.55	3.55	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.48
2021	3	3.55	3.55	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.48
2021	4	3.55	3.55	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.49
2021	5	3.56	3.56	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.50
2021	6	3.56	3.56	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.51
2021	7	3.56	3.56	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.51
2021	8	3.56	3.56	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.51
2021	9	3.56	3.56	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.51
2021	10	3.56	3.56	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.50
2021	11	3.56	3.56	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.50
2021	12	3.56	3.56	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.49

2022	1	3.56	3.56	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.49
2022	2	3.56	3.56	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.48
2022	3	3.57	3.57	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.49
2022	4	3.57	3.57	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.49
2022	5	3.57	3.57	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.50
2022	6	3.57	3.57	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.51
2022	7	3.57	3.57	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.51
2022	8	3.57	3.57	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.52
2022	9	3.57	3.57	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.51
2022	10	3.57	3.57	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.50
2022	11	3.57	3.57	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.50
2022	12	3.57	3.57	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.49
2023	1	3.57	3.57	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.49
2023	2	3.58	3.58	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.49
2023	3	3.58	3.58	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.49
2023	4	3.58	3.58	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.49
2023	5	3.58	3.58	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.50
2023	6	3.58	3.58	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.51
2023	7	3.58	3.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.51
2023	8	3.58	3.58	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.52
2023	9	3.58	3.58	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.51
2023	10	3.58	3.58	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.51
2023	11	3.58	3.58	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.50
2023	12	3.58	3.58	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.49
2024	1	3.58	3.58	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.49
2024	2	3.59	3.59	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.49
2024	3	3.59	3.59	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.49
2024	4	3.59	3.59	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.50
2024	5	3.59	3.59	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.51
2024	6	3.59	3.59	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.51
2024	7	3.59	3.59	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.51
2024	8	3.59	3.59	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.52
2024	9	3.59	3.59	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.51
2024	10	3.59	3.59	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.51
2024	11	3.59	3.59	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.50

2024	12	3.59	3.59	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.49
2025	1	3.59	3.59	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.49
2025	2	3.60	3.60	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.49
2025	3	3.60	3.60	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.49
2025	4	3.60	3.60	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.50
2025	5	3.60	3.60	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.51
2025	6	3.60	3.60	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.51
2025	7	3.60	3.60	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.52
2025	8	3.60	3.60	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.52
2025	9	3.60	3.60	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.52
2025	10	3.60	3.60	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.51
2025	11	3.60	3.60	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.50
2025	12	3.60	3.60	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.50
2026	1	3.60	3.60	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.50
2026	2	3.61	3.61	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.49
2026	3	3.61	3.61	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.50
2026	4	3.61	3.61	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.50
2026	5	3.61	3.61	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.51
2026	6	3.61	3.61	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.52
2026	7	3.61	3.61	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.52
2026	8	3.61	3.61	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.53
2026	9	3.61	3.61	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.52
2026	10	3.61	3.61	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.51
2026	11	3.61	3.61	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.51
2026	12	3.61	3.61	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.50
2027	1	3.62	3.62	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.50
2027	2	3.62	3.62	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.49
2027	3	3.62	3.62	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.50
2027	4	3.62	3.62	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.50
2027	5	3.62	3.62	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.51
2027	6	3.62	3.62	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.52
2027	7	3.62	3.62	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.52
2027	8	3.62	3.62	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.53
2027	9	3.62	3.62	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.52
2027	10	3.62	3.62	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.51

2027	11	3.62	3.62	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.51
2027	12	3.62	3.62	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.50
2028	1	3.62	3.62	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.50
2028	2	3.63	3.63	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.50
2028	3	3.63	3.63	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.50
2028	4	3.63	3.63	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.50
2028	5	3.63	3.63	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.51
2028	6	3.63	3.63	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.52
2028	7	3.63	3.63	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.52
2028	8	3.63	3.63	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.53
2028	9	3.63	3.63	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.52
2028	10	3.63	3.63	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.52
2028	11	3.63	3.63	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.51
2028	12	3.63	3.63	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.50
2029	1	3.63	3.63	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.50
2029	2	3.64	3.64	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.50
2029	3	3.64	3.64	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.50
2029	4	3.64	3.64	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.51
2029	5	3.64	3.64	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.52
2029	6	3.64	3.64	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.52
2029	7	3.64	3.64	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.52
2029	8	3.64	3.64	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.53
2029	9	3.64	3.64	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.52
2029	10	3.64	3.64	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.52
2029	11	3.64	3.64	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.51
2029	12	3.64	3.64	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.50
2030	1	3.64	3.64	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.50
2030	2	3.64	3.64	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.50
2030	3	3.65	3.65	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.50
2030	4	3.65	3.65	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.51
2030	5	3.65	3.65	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.52
2030	6	3.65	3.65	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.52
2030	7	3.65	3.65	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.53
2030	8	3.65	3.65	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.53
2030	9	3.65	3.65	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.53

2030	10	3.65	3.65	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.52
2030	11	3.65	3.65	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.51
2030	12	3.65	3.65	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.51
2031	1	3.65	3.65	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.51
2031	2	3.65	3.65	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.50
2031	3	3.65	3.65	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.50
2031	4	3.65	3.65	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.51
2031	5	3.66	3.66	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.52
2031	6	3.66	3.66	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.53
2031	7	3.66	3.66	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.53
2031	8	3.66	3.66	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.53
2031	9	3.66	3.66	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.53
2031	10	3.66	3.66	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.52
2031	11	3.66	3.66	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.52
2031	12	3.66	3.66	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.51
2032	1	3.66	3.66	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.51
2032	2	3.66	3.66	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.50
2032	3	3.66	3.66	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.51
2032	4	3.66	3.66	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.51
2032	5	3.66	3.66	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.52
2032	6	3.66	3.66	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.53
2032	7	3.67	3.67	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.53
2032	8	3.67	3.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.54
2032	9	3.67	3.67	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.53
2032	10	3.67	3.67	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.52
2032	11	3.67	3.67	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.52
2032	12	3.67	3.67	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.51
2033	1	3.67	3.67	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.51
2033	2	3.67	3.67	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.51
2033	3	3.67	3.67	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.51
2033	4	3.67	3.67	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.51
2033	5	3.67	3.67	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.52
2033	6	3.67	3.67	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.53
2033	7	3.67	3.67	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.53
2033	8	3.67	3.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.54

2033	9	3.67	3.67	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.53
2033	10	3.68	3.68	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.53
2033	11	3.68	3.68	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.52
2033	12	3.68	3.68	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.51
2034	1	3.68	3.68	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.51
2034	2	3.68	3.68	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.51
2034	3	3.68	3.68	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.51
2034	4	3.68	3.68	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.51
2034	5	3.68	3.68	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.52
2034	6	3.68	3.68	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.53
2034	7	3.68	3.68	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.53
2034	8	3.68	3.68	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.54
2034	9	3.68	3.68	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.53
2034	10	3.68	3.68	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.53
2034	11	3.68	3.68	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.52
2034	12	3.68	3.68	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.51
2035	1	3.69	3.69	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.51
2035	2	3.69	3.69	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.51
2035	3	3.69	3.69	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.51
2035	4	3.69	3.69	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.52
2035	5	3.69	3.69	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.53
2035	6	3.69	3.69	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.53
2035	7	3.69	3.69	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.53
2035	8	3.69	3.69	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.54
2035	9	3.69	3.69	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.53
2035	10	3.69	3.69	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.53
2035	11	3.69	3.69	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.52
2035	12	3.69	3.69	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.51
2036	1	3.69	3.69	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.51
2036	2	3.69	3.69	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.51
2036	3	3.69	3.69	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.51
2036	4	3.69	3.69	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.52
2036	5	3.70	3.70	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.53
2036	6	3.70	3.70	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.53
2036	7	3.70	3.70	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.54

2036	8	3.70	3.70	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.54
2036	9	3.70	3.70	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.54
2036	10	3.70	3.70	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.53
2036	11	3.70	3.70	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.52
2036	12	3.70	3.70	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.52
2037	1	3.70	3.70	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.52
2037	2	3.70	3.70	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.51
2037	3	3.70	3.70	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.51
2037	4	3.70	3.70	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.52
2037	5	3.70	3.70	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.53
2037	6	3.70	3.70	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.53
2037	7	3.70	3.70	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.54
2037	8	3.70	3.70	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.54
2037	9	3.70	3.70	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.54
2037	10	3.70	3.70	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.53
2037	11	3.71	3.71	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.53
2037	12	3.71	3.71	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.52
2038	1	3.71	3.71	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.52
2038	2	3.71	3.71	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.51
2038	3	3.71	3.71	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.52
2038	4	3.71	3.71	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.52
2038	5	3.71	3.71	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.53
2038	6	3.71	3.71	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.54
2038	7	3.71	3.71	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.54
2038	8	3.71	3.71	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.55
2038	9	3.71	3.71	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.54
2038	10	3.71	3.71	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.53
2038	11	3.71	3.71	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.53
2038	12	3.71	3.71	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.52
2039	1	3.71	3.71	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.52
2039	2	3.71	3.71	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.51
2039	3	3.71	3.71	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.52
2039	4	3.72	3.72	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.52
2039	5	3.72	3.72	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.53
2039	6	3.72	3.72	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.54

2039	7	3.72	3.72	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.54
2039	8	3.72	3.72	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.55
2039	9	3.72	3.72	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.54
2039	10	3.72	3.72	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.53
2039	11	3.72	3.72	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.53
2039	12	3.72	3.72	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.52
2040	1	3.72	3.72	1.00	1	-	-	-	-	-	-	-	-	-	-	-	9.52
2040	2	3.72	3.72	1.00	-	1	-	-	-	-	-	-	-	-	-	-	9.52
2040	3	3.72	3.72	1.00	-	-	1	-	-	-	-	-	-	-	-	-	9.52
2040	4	3.72	3.72	1.00	-	-	-	1	-	-	-	-	-	-	-	-	9.52
2040	5	3.72	3.72	1.00	-	-	-	-	1	-	-	-	-	-	-	-	9.53
2040	6	3.72	3.72	1.00	-	-	-	-	-	1	-	-	-	-	-	-	9.54
2040	7	3.72	3.72	1.00	-	-	-	-	-	-	1	-	-	-	-	-	9.54
2040	8	3.72	3.72	1.00	-	-	-	-	-	-	-	1	-	-	-	-	9.55
2040	9	3.72	3.72	1.00	-	-	-	-	-	-	-	-	1	-	-	-	9.54
2040	10	3.72	3.72	1.00	-	-	-	-	-	-	-	-	-	1	-	-	9.54
2040	11	3.73	3.73	1.00	-	-	-	-	-	-	-	-	-	-	1	-	9.53
2040	12	3.73	3.73	1.00	-	-	-	-	-	-	-	-	-	-	-	1	9.52

Schedule C-17. Black Hills Power: Variable Statistical Values for Commercial Customer Model

Black Hills Power **Confidential Appendix C**

Black Hills Power: Variable Statistical Values for Commercial Customer Model **Schedule C-17**

Variable	Coefficient	Standard Error	P Value	R2 = 0.9987
class_shift	4.492	0.715	0.000	
lntotemp12	1.490	0.042	0.000	
lntotemp_shift	-1.292	0.205	0.000	
m2	-0.004	0.002	0.062	
m3	-0.002	0.003	0.567	
m4	0.004	0.003	0.231	
m5	0.013	0.003	0.000	
m6	0.019	0.003	0.000	
m7	0.021	0.003	0.000	
m8	0.028	0.003	0.000	
m9	0.021	0.003	0.000	
m10	0.015	0.003	0.000	
m11	0.009	0.003	0.001	
m12	0.000	0.002	0.913	
_cons	4.291	0.142	0.000	

Schedule C-18. Black Hills Power: Historical and Forecasted Variable Values for Municipal Sales Model

Black Hills Power **Confidential Appendix C**

Black Hills Power: Historical and Forecasted Variable Values for Municipal Sales Model **Schedule C-18**

Year	Month	cdd60	trend	trend_d2007	d2007	m1	m2	m3	m4	m5	m6	m7	m8	m9	m10	m11	m12	ln(sales)
1999	1	0.00	1.08	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	6.93
1999	2	0.00	1.17	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	6.83
1999	3	0.00	1.25	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	6.86
1999	4	0.00	1.33	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	6.86
1999	5	0.00	1.42	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	6.93
1999	6	48.74	1.50	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	7.12
1999	7	218.47	1.58	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	7.31
1999	8	347.16	1.67	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	7.38
1999	9	207.17	1.75	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	7.27
1999	10	28.79	1.83	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	7.06
1999	11	5.02	1.92	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	6.84
1999	12	0.00	2.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	6.94
2000	1	0.00	2.08	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	6.99
2000	2	0.00	2.17	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	6.88
2000	3	0.00	2.25	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	6.91
2000	4	0.00	2.33	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	6.91
2000	5	20.18	2.42	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	7.00
2000	6	111.60	2.50	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	7.24
2000	7	297.28	2.58	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	7.44
2000	8	434.14	2.67	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	7.52
2000	9	327.61	2.75	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	7.44
2000	10	65.69	2.83	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	7.15
2000	11	5.48	2.92	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	6.89
2000	12	0.00	3.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	6.99
2001	1	0.00	3.08	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	7.04
2001	2	0.00	3.17	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	6.94
2001	3	0.00	3.25	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	6.97
2001	4	0.00	3.33	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	6.97
2001	5	61.56	3.42	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	7.10
2001	6	44.17	3.50	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	7.23
2001	7	336.43	3.58	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	7.53

2001	8	474.68	3.67	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	7.62
2001	9	305.55	3.75	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	7.47
2001	10	53.27	3.83	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	7.19
2001	11	0.00	3.92	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	6.94
2001	12	0.00	4.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	7.05
2002	1	0.00	4.08	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	7.09
2002	2	0.00	4.17	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	6.99
2002	3	0.00	4.25	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	7.02
2002	4	5.76	4.33	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	7.03
2002	5	0.17	4.42	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	7.09
2002	6	79.68	4.50	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	7.32
2002	7	470.99	4.58	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	7.72
2002	8	437.21	4.67	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	7.63
2002	9	298.29	4.75	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	7.52
2002	10	20.39	4.83	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	7.21
2002	11	0.00	4.92	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	6.99
2002	12	0.00	5.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	7.10
2003	1	0.00	5.08	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	7.15
2003	2	0.00	5.17	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	7.04
2003	3	0.00	5.25	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	7.07
2003	4	9.56	5.33	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	7.08
2003	5	0.00	5.42	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	7.14
2003	6	74.53	5.50	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	7.36
2003	7	317.23	5.58	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	7.62
2003	8	567.83	5.67	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	7.82
2003	9	342.84	5.75	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	7.62
2003	10	32.09	5.83	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	7.28
2003	11	32.49	5.92	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	7.08
2003	12	0.00	6.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	7.15
2004	1	0.00	6.08	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	7.20
2004	2	0.00	6.17	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	7.10
2004	3	0.00	6.25	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	7.13
2004	4	0.00	6.33	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	7.13
2004	5	29.36	6.42	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	7.22
2004	6	77.39	6.50	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	7.42

2004	7	207.04	6.58	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	7.56
2004	8	334.73	6.67	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	7.63
2004	9	230.53	6.75	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	7.56
2004	10	50.46	6.83	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	7.35
2004	11	0.00	6.92	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	7.10
2004	12	0.00	7.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	7.21
2005	1	0.00	7.08	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	7.25
2005	2	0.00	7.17	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	7.15
2005	3	0.00	7.25	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	7.18
2005	4	3.87	7.33	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	7.19
2005	5	10.19	7.42	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	7.26
2005	6	58.36	7.50	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	7.45
2005	7	421.89	7.58	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	7.83
2005	8	433.00	7.67	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	7.79
2005	9	292.74	7.75	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	7.67
2005	10	59.34	7.83	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	7.41
2005	11	3.76	7.92	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	7.16
2005	12	0.00	8.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	7.26
2006	1	0.00	8.08	0.00	0.00	1	-	-	-	-	-	-	-	-	-	-	-	7.31
2006	2	0.00	8.17	0.00	0.00	-	1	-	-	-	-	-	-	-	-	-	-	7.20
2006	3	0.00	8.25	0.00	0.00	-	-	1	-	-	-	-	-	-	-	-	-	7.23
2006	4	10.13	8.33	0.00	0.00	-	-	-	1	-	-	-	-	-	-	-	-	7.24
2006	5	0.17	8.42	0.00	0.00	-	-	-	-	1	-	-	-	-	-	-	-	7.30
2006	6	227.93	8.50	0.00	0.00	-	-	-	-	-	1	-	-	-	-	-	-	7.68
2006	7	384.33	8.58	0.00	0.00	-	-	-	-	-	-	1	-	-	-	-	-	7.85
2006	8	532.33	8.67	0.00	0.00	-	-	-	-	-	-	-	1	-	-	-	-	7.94
2006	9	223.90	8.75	0.00	0.00	-	-	-	-	-	-	-	-	1	-	-	-	7.66
2006	10	31.03	8.83	0.00	0.00	-	-	-	-	-	-	-	-	-	1	-	-	7.44
2006	11	3.58	8.92	0.00	0.00	-	-	-	-	-	-	-	-	-	-	1	-	7.21
2006	12	0.00	9.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	1	7.31
2007	1	0.00	9.08	9.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.51
2007	2	0.00	9.17	9.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.40
2007	3	1.41	9.25	9.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.43
2007	4	0.00	9.33	9.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.42
2007	5	37.77	9.42	9.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.52

2007	6	111.09	9.50	9.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.74
2007	7	433.51	9.58	9.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	8.07
2007	8	581.74	9.67	9.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	8.16
2007	9	233.55	9.75	9.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.83
2007	10	71.56	9.83	9.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.63
2007	11	2.57	9.92	9.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.36
2007	12	0.00	10.00	10.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.46
2008	1	0.00	10.08	10.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.50
2008	2	0.00	10.17	10.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.39
2008	3	0.00	10.25	10.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.42
2008	4	2.90	10.33	10.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.41
2008	5	0.00	10.42	10.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.47
2008	6	27.85	10.50	10.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.64
2008	7	263.73	10.58	10.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.88
2008	8	407.08	10.67	10.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.97
2008	9	207.10	10.75	10.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.79
2008	10	90.87	10.83	10.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.64
2008	11	3.95	10.92	10.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.35
2008	12	0.00	11.00	11.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.44
2009	1	0.00	11.08	11.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.49
2009	2	0.00	11.17	11.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.38
2009	3	0.00	11.25	11.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.40
2009	4	2.59	11.33	11.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.40
2009	5	7.12	11.42	11.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.47
2009	6	63.71	11.50	11.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.66
2009	7	269.27	11.58	11.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.88
2009	8	287.01	11.67	11.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.83
2009	9	215.55	11.75	11.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.78
2009	10	43.57	11.83	11.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.58
2009	11	1.86	11.92	11.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.33
2009	12	0.00	12.00	12.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.43
2010	1	0.00	12.08	12.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.47
2010	2	0.00	12.17	12.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.37
2010	3	0.00	12.25	12.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.39
2010	4	0.00	12.33	12.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.38

2010	5	0.00	12.42	12.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.45
2010	6	52.60	12.50	12.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.64
2010	7	267.11	12.58	12.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.86
2010	8	409.78	12.67	12.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.95
2010	9	260.52	12.75	12.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.82
2010	10	65.67	12.83	12.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.59
2010	11	3.10	12.92	12.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.32
2010	12	0.00	13.00	13.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.42
2011	1	0.00	13.08	13.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.46
2011	2	0.00	13.17	13.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.35
2011	3	0.00	13.25	13.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.38
2011	4	0.00	13.33	13.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.37
2011	5	0.36	13.42	13.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.43
2011	6	53.04	13.50	13.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.63
2011	7	255.64	13.58	13.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.84
2011	8	469.64	13.67	13.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.99
2011	9	307.72	13.75	13.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.85
2011	10	108.73	13.83	13.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.62
2011	11	0.00	13.92	13.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.30
2011	12	0.00	14.00	14.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.41
2012	1	0.00	14.08	14.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.45
2012	2	0.00	14.17	14.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.34
2012	3	0.00	14.25	14.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.36
2012	4	16.33	14.33	14.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.38
2012	5	35.70	14.42	14.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.46
2012	6	168.46	14.50	14.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.73
2012	7	467.16	14.58	14.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	8.04
2012	8	500.17	14.67	14.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	8.01
2012	9	349.58	14.75	14.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.88
2012	10	33.83	14.83	14.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.53
2012	11	1.98	14.92	14.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.29
2012	12	0.00	15.00	15.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.39
2013	1	0.00	15.08	15.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.43
2013	2	0.00	15.17	15.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.33
2013	3	0.00	15.25	15.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.35

2013	4	0.00	15.33	15.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.35
2013	5	26.75	15.42	15.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.43
2013	6	73.84	15.50	15.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.62
2013	7	353.98	15.58	15.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.91
2013	8	319.51	15.67	15.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.82
2013	9	447.95	15.75	15.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.97
2013	10	51.90	15.83	15.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.54
2013	11	0.00	15.92	15.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.28
2013	12	0.00	16.00	16.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.38
2014	1	0.00	16.08	16.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.42
2014	2	0.00	16.17	16.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.31
2014	3	0.00	16.25	16.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.34
2014	4	0.00	16.33	16.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.33
2014	5	0.00	16.42	16.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.39
2014	6	71.54	16.50	16.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.61
2014	7	231.94	16.58	16.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.77
2014	8	373.24	16.67	16.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.86
2014	9	168.71	16.75	16.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.67
2014	10	100.48	16.83	16.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.57
2014	11	4.85	16.92	16.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.27
2014	12	0.00	17.00	17.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.37
2015	1	0.00	17.08	17.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.41
2015	2	0.00	17.17	17.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.30
2015	3	7.67	17.25	17.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.33
2015	4	0.00	17.33	17.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.32
2015	5	4.95	17.42	17.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.39
2015	6	84.30	17.50	17.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.61
2015	7	296.16	17.58	17.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.83
2015	8	405.69	17.67	17.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.88
2015	9	276.69	17.75	17.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.77
2015	10	83.99	17.83	17.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.54
2015	11	4.32	17.92	17.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.26
2015	12	0.00	18.00	18.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.36
2016	1	0.00	18.08	18.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.40
2016	2	0.00	18.17	18.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.29

2016	3	0.00	18.25	18.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.31
2016	4	2.19	18.33	18.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.31
2016	5	15.33	18.42	18.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.38
2016	6	175.51	18.50	18.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.69
2016	7	385.76	18.58	18.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.91
2016	8	448.44	18.67	18.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.91
2016	9	201.42	18.75	18.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.68
2016	10	50.74	18.83	18.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.50
2016	11	10.63	18.92	18.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.25
2016	12	0.00	19.00	19.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.34
2017	1	0.00	19.08	19.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.38
2017	2	0.00	19.17	19.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.28
2017	3	0.00	19.25	19.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.30
2017	4	0.34	19.33	19.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.30
2017	5	34.21	19.42	19.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.39
2017	6	151.74	19.50	19.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.65
2017	7	356.84	19.58	19.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.86
2017	8	373.98	19.67	19.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.82
2017	9	341.63	19.75	19.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.81
2017	10	8.67	19.83	19.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.44
2017	11	11.42	19.92	19.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.24
2017	12	1.72	20.00	20.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.33
2018	1	0.00	20.08	20.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.37
2018	2	0.00	20.17	20.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.26
2018	3	0.00	20.25	20.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.29
2018	4	0.00	20.33	20.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.28
2018	5	23.56	20.42	20.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.37
2018	6	241.83	20.50	20.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.73
2018	7	280.84	20.58	20.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.77
2018	8	330.30	20.67	20.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.76
2018	9	227.71	20.75	20.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.68
2018	10	18.46	20.83	20.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.44
2018	11	0.00	20.92	20.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.21
2018	12	0.00	21.00	21.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.32
2019	1	0.00	21.08	21.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.36

2019	2	0.00	21.17	21.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.25
2019	3	0.00	21.25	21.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.28
2019	4	0.00	21.33	21.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.27
2019	5	11.09	21.42	21.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.34
2019	6	69.61	21.50	21.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.54
2019	7	216.99	21.58	21.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.70
2019	8	318.42	21.67	21.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.74
2019	9	195.88	21.75	21.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.64
2019	10	50.03	21.83	21.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.46
2019	11	0.00	21.92	21.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.20
2019	12	0.00	22.00	22.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.30
2020	1	0.00	22.08	22.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.34
2020	2	0.00	22.17	22.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.24
2020	3	0.43	22.25	22.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.26
2020	4	2.56	22.33	22.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.26
2020	5	15.17	22.42	22.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.33
2020	6	98.45	22.50	22.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.56
2020	7	320.60	22.58	22.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.79
2020	8	418.38	22.67	22.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.83
2020	9	269.65	22.75	22.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.70
2020	10	53.31	22.83	22.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.45
2020	11	4.52	22.92	22.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.19
2020	12	0.08	23.00	23.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.29
2021	1	0.00	23.08	23.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.33
2021	2	0.00	23.17	23.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.22
2021	3	0.43	23.25	23.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.25
2021	4	2.56	23.33	23.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.25
2021	5	15.17	23.42	23.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.32
2021	6	98.45	23.50	23.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.55
2021	7	320.60	23.58	23.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.78
2021	8	418.38	23.67	23.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.81
2021	9	269.65	23.75	23.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.69
2021	10	53.31	23.83	23.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.43
2021	11	4.52	23.92	23.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.18
2021	12	0.08	24.00	24.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.28

2022	1	0.00	24.08	24.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.32
2022	2	0.00	24.17	24.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.21
2022	3	0.43	24.25	24.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.24
2022	4	2.56	24.33	24.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.23
2022	5	15.17	24.42	24.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.31
2022	6	98.45	24.50	24.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.53
2022	7	320.60	24.58	24.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.76
2022	8	418.38	24.67	24.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.80
2022	9	269.65	24.75	24.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.67
2022	10	53.31	24.83	24.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.42
2022	11	4.52	24.92	24.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.17
2022	12	0.08	25.00	25.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.27
2023	1	0.00	25.08	25.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.31
2023	2	0.00	25.17	25.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.20
2023	3	0.43	25.25	25.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.22
2023	4	2.56	25.33	25.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.22
2023	5	15.17	25.42	25.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.29
2023	6	98.45	25.50	25.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.52
2023	7	320.60	25.58	25.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.75
2023	8	418.38	25.67	25.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.79
2023	9	269.65	25.75	25.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.66
2023	10	53.31	25.83	25.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.41
2023	11	4.52	25.92	25.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.15
2023	12	0.08	26.00	26.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.25
2024	1	0.00	26.08	26.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.29
2024	2	0.00	26.17	26.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.19
2024	3	0.43	26.25	26.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.21
2024	4	2.56	26.33	26.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.21
2024	5	15.17	26.42	26.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.28
2024	6	98.45	26.50	26.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.51
2024	7	320.60	26.58	26.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.74
2024	8	418.38	26.67	26.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.77
2024	9	269.65	26.75	26.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.65
2024	10	53.31	26.83	26.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.40
2024	11	4.52	26.92	26.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.14

2024	12	0.08	27.00	27.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.24
2025	1	0.00	27.08	27.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.28
2025	2	0.00	27.17	27.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.17
2025	3	0.43	27.25	27.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.20
2025	4	2.56	27.33	27.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.20
2025	5	15.17	27.42	27.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.27
2025	6	98.45	27.50	27.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.50
2025	7	320.60	27.58	27.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.72
2025	8	418.38	27.67	27.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.76
2025	9	269.65	27.75	27.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.63
2025	10	53.31	27.83	27.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.38
2025	11	4.52	27.92	27.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.13
2025	12	0.08	28.00	28.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.23
2026	1	0.00	28.08	28.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.27
2026	2	0.00	28.17	28.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.16
2026	3	0.43	28.25	28.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.19
2026	4	2.56	28.33	28.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.18
2026	5	15.17	28.42	28.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.26
2026	6	98.45	28.50	28.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.48
2026	7	320.60	28.58	28.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.71
2026	8	418.38	28.67	28.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.75
2026	9	269.65	28.75	28.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.62
2026	10	53.31	28.83	28.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.37
2026	11	4.52	28.92	28.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.12
2026	12	0.08	29.00	29.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.21
2027	1	0.00	29.08	29.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.26
2027	2	0.00	29.17	29.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.15
2027	3	0.43	29.25	29.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.17
2027	4	2.56	29.33	29.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.17
2027	5	15.17	29.42	29.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.24
2027	6	98.45	29.50	29.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.47
2027	7	320.60	29.58	29.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.70
2027	8	418.38	29.67	29.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.74
2027	9	269.65	29.75	29.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.61
2027	10	53.31	29.83	29.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.36

2027	11	4.52	29.92	29.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.10
2027	12	0.08	30.00	30.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.20
2028	1	0.00	30.08	30.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.24
2028	2	0.00	30.17	30.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.14
2028	3	0.43	30.25	30.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.16
2028	4	2.56	30.33	30.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.16
2028	5	15.17	30.42	30.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.23
2028	6	98.45	30.50	30.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.46
2028	7	320.60	30.58	30.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.69
2028	8	418.38	30.67	30.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.72
2028	9	269.65	30.75	30.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.60
2028	10	53.31	30.83	30.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.35
2028	11	4.52	30.92	30.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.09
2028	12	0.08	31.00	31.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.19
2029	1	0.00	31.08	31.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.23
2029	2	0.00	31.17	31.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.12
2029	3	0.43	31.25	31.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.15
2029	4	2.56	31.33	31.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.14
2029	5	15.17	31.42	31.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.22
2029	6	98.45	31.50	31.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.44
2029	7	320.60	31.58	31.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.67
2029	8	418.38	31.67	31.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.71
2029	9	269.65	31.75	31.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.58
2029	10	53.31	31.83	31.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.33
2029	11	4.52	31.92	31.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.08
2029	12	0.08	32.00	32.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.18
2030	1	0.00	32.08	32.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.22
2030	2	0.00	32.17	32.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.11
2030	3	0.43	32.25	32.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.13
2030	4	2.56	32.33	32.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.13
2030	5	15.17	32.42	32.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.20
2030	6	98.45	32.50	32.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.43
2030	7	320.60	32.58	32.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.66
2030	8	418.38	32.67	32.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.70
2030	9	269.65	32.75	32.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.57

2030	10	53.31	32.83	32.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.32
2030	11	4.52	32.92	32.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.06
2030	12	0.08	33.00	33.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.16
2031	1	0.00	33.08	33.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.20
2031	2	0.00	33.17	33.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.10
2031	3	0.43	33.25	33.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.12
2031	4	2.56	33.33	33.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.12
2031	5	15.17	33.42	33.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.19
2031	6	98.45	33.50	33.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.42
2031	7	320.60	33.58	33.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.65
2031	8	418.38	33.67	33.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.69
2031	9	269.65	33.75	33.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.56
2031	10	53.31	33.83	33.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.31
2031	11	4.52	33.92	33.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.05
2031	12	0.08	34.00	34.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.15
2032	1	0.00	34.08	34.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.19
2032	2	0.00	34.17	34.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.08
2032	3	0.43	34.25	34.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.11
2032	4	2.56	34.33	34.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.11
2032	5	15.17	34.42	34.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.18
2032	6	98.45	34.50	34.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.41
2032	7	320.60	34.58	34.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.63
2032	8	418.38	34.67	34.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.67
2032	9	269.65	34.75	34.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.54
2032	10	53.31	34.83	34.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.29
2032	11	4.52	34.92	34.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.04
2032	12	0.08	35.00	35.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.14
2033	1	0.00	35.08	35.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.18
2033	2	0.00	35.17	35.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.07
2033	3	0.43	35.25	35.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.10
2033	4	2.56	35.33	35.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.09
2033	5	15.17	35.42	35.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.17
2033	6	98.45	35.50	35.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.39
2033	7	320.60	35.58	35.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.62
2033	8	418.38	35.67	35.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.66

2033	9	269.65	35.75	35.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.53
2033	10	53.31	35.83	35.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.28
2033	11	4.52	35.92	35.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.03
2033	12	0.08	36.00	36.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.12
2034	1	0.00	36.08	36.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.17
2034	2	0.00	36.17	36.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.06
2034	3	0.43	36.25	36.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.08
2034	4	2.56	36.33	36.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.08
2034	5	15.17	36.42	36.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.15
2034	6	98.45	36.50	36.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.38
2034	7	320.60	36.58	36.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.61
2034	8	418.38	36.67	36.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.65
2034	9	269.65	36.75	36.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.52
2034	10	53.31	36.83	36.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.27
2034	11	4.52	36.92	36.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.01
2034	12	0.08	37.00	37.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.11
2035	1	0.00	37.08	37.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.15
2035	2	0.00	37.17	37.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.05
2035	3	0.43	37.25	37.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.07
2035	4	2.56	37.33	37.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.07
2035	5	15.17	37.42	37.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.14
2035	6	98.45	37.50	37.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.37
2035	7	320.60	37.58	37.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.60
2035	8	418.38	37.67	37.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.63
2035	9	269.65	37.75	37.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.51
2035	10	53.31	37.83	37.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.26
2035	11	4.52	37.92	37.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	7.00
2035	12	0.08	38.00	38.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.10
2036	1	0.00	38.08	38.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.14
2036	2	0.00	38.17	38.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.03
2036	3	0.43	38.25	38.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.06
2036	4	2.56	38.33	38.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.05
2036	5	15.17	38.42	38.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.13
2036	6	98.45	38.50	38.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.35
2036	7	320.60	38.58	38.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.58

2036	8	418.38	38.67	38.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.62
2036	9	269.65	38.75	38.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.49
2036	10	53.31	38.83	38.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.24
2036	11	4.52	38.92	38.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	6.99
2036	12	0.08	39.00	39.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.09
2037	1	0.00	39.08	39.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.13
2037	2	0.00	39.17	39.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.02
2037	3	0.43	39.25	39.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.05
2037	4	2.56	39.33	39.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.04
2037	5	15.17	39.42	39.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.11
2037	6	98.45	39.50	39.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.34
2037	7	320.60	39.58	39.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.57
2037	8	418.38	39.67	39.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.61
2037	9	269.65	39.75	39.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.48
2037	10	53.31	39.83	39.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.23
2037	11	4.52	39.92	39.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	6.98
2037	12	0.08	40.00	40.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.07
2038	1	0.00	40.08	40.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.11
2038	2	0.00	40.17	40.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	7.01
2038	3	0.43	40.25	40.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.03
2038	4	2.56	40.33	40.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.03
2038	5	15.17	40.42	40.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.10
2038	6	98.45	40.50	40.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.33
2038	7	320.60	40.58	40.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.56
2038	8	418.38	40.67	40.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.60
2038	9	269.65	40.75	40.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.47
2038	10	53.31	40.83	40.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.22
2038	11	4.52	40.92	40.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	6.96
2038	12	0.08	41.00	41.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.06
2039	1	0.00	41.08	41.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.10
2039	2	0.00	41.17	41.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	6.99
2039	3	0.43	41.25	41.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.02
2039	4	2.56	41.33	41.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.02
2039	5	15.17	41.42	41.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.09
2039	6	98.45	41.50	41.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.32

2039	7	320.60	41.58	41.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.55
2039	8	418.38	41.67	41.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.58
2039	9	269.65	41.75	41.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.46
2039	10	53.31	41.83	41.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.20
2039	11	4.52	41.92	41.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	6.95
2039	12	0.08	42.00	42.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.05
2040	1	0.00	42.08	42.08	1.00	1	-	-	-	-	-	-	-	-	-	-	-	7.09
2040	2	0.00	42.17	42.17	1.00	-	1	-	-	-	-	-	-	-	-	-	-	6.98
2040	3	0.43	42.25	42.25	1.00	-	-	1	-	-	-	-	-	-	-	-	-	7.01
2040	4	2.56	42.33	42.33	1.00	-	-	-	1	-	-	-	-	-	-	-	-	7.00
2040	5	15.17	42.42	42.42	1.00	-	-	-	-	1	-	-	-	-	-	-	-	7.08
2040	6	98.45	42.50	42.50	1.00	-	-	-	-	-	1	-	-	-	-	-	-	7.30
2040	7	320.60	42.58	42.58	1.00	-	-	-	-	-	-	1	-	-	-	-	-	7.53
2040	8	418.38	42.67	42.67	1.00	-	-	-	-	-	-	-	1	-	-	-	-	7.57
2040	9	269.65	42.75	42.75	1.00	-	-	-	-	-	-	-	-	1	-	-	-	7.44
2040	10	53.31	42.83	42.83	1.00	-	-	-	-	-	-	-	-	-	1	-	-	7.19
2040	11	4.52	42.92	42.92	1.00	-	-	-	-	-	-	-	-	-	-	1	-	6.94
2040	12	0.08	43.00	43.00	1.00	-	-	-	-	-	-	-	-	-	-	-	1	7.04

Schedule C-19. Black Hills Power: Variable Statistical Values for Municipal Sales Model

Black Hills Power **Confidential Appendix C**

Black Hills Power: Variable Statistical Values for Municipal Sales Model **Schedule C-19**

Variable	Coefficient	Standard Error	P Value	R2 = 0.8391
cdd60	0.001	0.000	0.000	
trend	0.053	0.006	0.000	
trend_d2007	-0.066	0.007	0.000	
d2007	0.753	0.059	0.000	
m2	-0.106	0.029	0.000	
m3	-0.080	0.032	0.014	
m4	-0.085	0.033	0.011	
m5	-0.023	0.033	0.487	
m6	0.120	0.037	0.001	
m7	0.124	0.062	0.045	
m8	0.064	0.075	0.400	
m9	0.088	0.055	0.109	
m10	0.059	0.034	0.090	
m11	-0.146	0.032	0.000	
m12	-0.042	0.029	0.154	
_cons	6.874	0.040	0.000	

Schedule C-20. Black Hills Power: Historical and Forecasted Values for Industrial Sales Model

Black Hills Power **Confidential Appendix C**

Black Hills Power: Historical and Forcasted Values for Industrial Sales **Schedule C-20**

Year	Month	Sales
1999	1	41,218.43
1999	2	37,275.32
1999	3	40,588.91
1999	4	41,026.47
1999	5	43,757.67
1999	6	45,742.55
1999	7	46,120.25
1999	8	46,553.34
1999	9	46,399.03
1999	10	46,795.32
1999	11	43,307.23
1999	12	42,288.18
2000	1	40,208.91
2000	2	39,588.19
2000	3	43,474.63
2000	4	37,714.97
2000	5	46,109.26
2000	6	44,351.10
2000	7	42,192.43
2000	8	45,951.34
2000	9	43,328.29
2000	10	42,587.86
2000	11	42,788.99
2000	12	41,757.20
2001	1	43,452.02
2001	2	39,861.78
2001	3	38,381.74
2001	4	40,342.90
2001	5	41,963.78
2001	6	45,023.28
2001	7	46,189.08
2001	8	44,714.34
2001	9	44,508.61
2001	10	40,802.96
2001	11	44,162.79
2001	12	39,452.56
2002	1	38,508.11
2002	2	31,687.23
2002	3	34,500.93
2002	4	31,917.90
2002	5	37,741.79
2002	6	34,315.25
2002	7	34,733.84

2002	8	36,249.71
2002	9	31,511.55
2002	10	34,650.14
2002	11	35,170.60
2002	12	32,943.43
2003	1	33,309.92
2003	2	31,290.40
2003	3	30,890.94
2003	4	30,823.92
2003	5	33,349.74
2003	6	34,074.50
2003	7	36,414.91
2003	8	35,374.56
2003	9	35,652.02
2003	10	34,466.26
2003	11	34,135.48
2003	12	34,557.88
2004	1	30,239.86
2004	2	33,017.32
2004	3	35,263.90
2004	4	30,389.59
2004	5	32,751.52
2004	6	35,604.09
2004	7	37,892.38
2004	8	36,670.68
2004	9	36,047.49
2004	10	35,031.32
2004	11	34,350.33
2004	12	28,951.03
2005	1	31,059.60
2005	2	33,542.49
2005	3	33,796.01
2005	4	31,726.75
2005	5	35,640.61
2005	6	36,327.14
2005	7	35,807.14
2005	8	37,503.83
2005	9	35,134.80
2005	10	35,845.84
2005	11	34,736.40
2005	12	36,507.28
2006	1	35,519.68
2006	2	32,984.10
2006	3	34,523.30
2006	4	33,745.93
2006	5	37,345.62
2006	6	37,241.50
2006	7	37,034.08

2006	8	37,579.79
2006	9	36,259.38
2006	10	37,942.99
2006	11	38,676.66
2006	12	34,166.13
2007	1	33,852.03
2007	2	31,703.26
2007	3	33,698.72
2007	4	35,934.45
2007	5	36,872.91
2007	6	37,196.73
2007	7	39,040.63
2007	8	37,753.20
2007	9	35,746.52
2007	10	36,463.38
2007	11	40,140.48
2007	12	36,224.57
2008	1	35,202.32
2008	2	33,797.51
2008	3	33,669.11
2008	4	33,850.52
2008	5	36,733.71
2008	6	38,443.63
2008	7	35,197.21
2008	8	36,597.50
2008	9	35,585.41
2008	10	31,163.93
2008	11	33,289.78
2008	12	30,889.96
2009	1	30,045.24
2009	2	28,408.09
2009	3	27,530.50
2009	4	28,284.61
2009	5	32,686.97
2009	6	33,012.42
2009	7	32,576.67
2009	8	35,696.73
2009	9	32,253.64
2009	10	31,923.21
2009	11	31,456.29
2009	12	29,472.21
2010	1	33,265.82
2010	2	31,865.23
2010	3	35,109.50
2010	4	37,554.50
2010	5	35,760.59
2010	6	39,215.10
2010	7	40,097.35

2010	8	33,789.34
2010	9	33,277.37
2010	10	34,740.26
2010	11	30,696.69
2010	12	35,749.59
2011	1	30,125.30
2011	2	27,541.75
2011	3	32,636.12
2011	4	35,988.78
2011	5	32,357.62
2011	6	35,333.11
2011	7	34,372.41
2011	8	35,415.50
2011	9	36,720.86
2011	10	35,113.94
2011	11	34,773.61
2011	12	35,380.86
2012	1	35,096.41
2012	2	31,060.49
2012	3	34,087.47
2012	4	36,199.60
2012	5	33,022.69
2012	6	35,486.36
2012	7	34,350.08
2012	8	34,358.66
2012	9	35,090.33
2012	10	31,536.92
2012	11	32,437.63
2012	12	33,309.95
2013	1	32,661.49
2013	2	29,950.74
2013	3	32,563.56
2013	4	30,251.71
2013	5	37,482.97
2013	6	33,944.10
2013	7	34,285.37
2013	8	33,614.76
2013	9	34,969.98
2013	10	34,460.76
2013	11	33,536.64
2013	12	36,808.83
2014	1	33,626.07
2014	2	35,548.47
2014	3	34,492.29
2014	4	35,648.40
2014	5	33,623.44
2014	6	32,993.49
2014	7	32,304.73

2014	8	33,193.58
2014	9	31,725.83
2014	10	33,438.15
2014	11	33,504.87
2014	12	35,282.59
2015	1	33,909.60
2015	2	34,578.80
2015	3	29,372.62
2015	4	32,487.43
2015	5	33,282.04
2015	6	34,589.14
2015	7	36,024.48
2015	8	36,854.85
2015	9	36,902.05
2015	10	35,445.44
2015	11	35,433.93
2015	12	34,133.74
2016	1	35,664.89
2016	2	35,322.76
2016	3	35,045.78
2016	4	38,045.85
2016	5	32,104.57
2016	6	35,876.17
2016	7	36,688.28
2016	8	33,732.76
2016	9	37,959.14
2016	10	36,455.61
2016	11	35,638.10
2016	12	37,486.74
2017	1	36,716.91
2017	2	37,230.74
2017	3	36,368.69
2017	4	35,170.10
2017	5	33,856.11
2017	6	34,551.71
2017	7	35,254.92
2017	8	37,050.98
2017	9	38,232.54
2017	10	33,899.64
2017	11	34,250.79
2017	12	36,851.08
2018	1	36,093.96
2018	2	35,160.89
2018	3	32,988.69
2018	4	36,653.07
2018	5	36,595.14
2018	6	35,487.13
2018	7	34,261.38

2018	8	35,271.26
2018	9	32,491.88
2018	10	27,610.08
2018	11	29,192.47
2018	12	33,177.24
2019	1	39,867.48
2019	2	36,121.81
2019	3	35,702.44
2019	4	36,027.70
2019	5	36,719.93
2019	6	38,438.75
2019	7	36,376.63
2019	8	40,674.51
2019	9	40,409.74
2019	10	40,256.46
2019	11	40,598.25
2019	12	41,879.30
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2025	12	41,879.30
2026	1	39,867.48
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2040	4	36,027.70
2040	5	36,719.93
2040	6	38,438.75
2040	7	36,376.63
2040	8	40,674.51
2040	9	40,409.74
2040	10	40,256.46
2040	11	40,598.25
2040	12	41,879.30

D. BUSBAR COST STUDY

The Busbar Cost Study presented cost and performance characteristics for 35 resource options for consideration in this IRP. The study recommended that the IRP consider modelling only 26 of these resource options, and eliminate the other nine from consideration. These 26, some with multiple location possibilities, are the options most likely to be cost-effective additions to the Cheyenne Light and Black Hills Power resource portfolios.

These 26 resource options, where possible, are based on a busbar model that states all unit costs—capital costs, fuel, and operating and maintenance (O&M) costs—on a levelized cents per kWh. The BESS resource option was evaluated over a 20-year period; all other resource options were evaluated for a 25-year period.

REV 2 – FINAL COMMENTS INCORPORATED

BLACK HILLS CORPORATION BUSBAR COST STUDY

B&V PROJECT NO. 407186
B&V FILE NO. 40.3000

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PREPARED FOR

Black Hills Corporation

26 MARCH 2021

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1.0 Executive Summary

The purpose of this busbar cost study is to develop cost and performance characteristics for approximately three dozen technologies that are being considered for the BHP and CLFP integrated resource plan (IRP) studies, and to recommend an initial screening of options not likely to be part of the final IRP plan. This initial screening will help reduce the time required for the detailed IRP production costing and expansion planning modeling.

Where possible, the initial screening recommendations in this report are based on the development of a busbar model for the selected options. A busbar model states all unit costs—capital costs, fuel, and operating and maintenance (O&M) costs—on a levelized cents/kWh basis, with a levelization period of 25 years in the analysis (except for the battery energy storage system (BESS) technology which was evaluated over a 20-year period).

In the main report, Section 2 provides several assumptions required for the busbar analysis performed. Section 3 lists the cost and performance information developed by Black & Veatch for the study options. Section 4 presents the busbar cost results for the selected technologies and Section 5 provides a discussion supporting the recommended screening of options from further consideration in the detailed IRP modeling.

Table 1-1 lists the 35 options studied (some options involve multiple location options) and indicates whether the technology is recommended for consideration as a candidate option in the full IRP modeling. Table 1-2 lists the complete busbar results that drive the recommendations in the study. This table is a comprehensive results list compiled from the individual busbar result tables in Section 4, where busbar curves are also presented according to specific locational and technology groups. Appendix A provides a sample busbar sheet for the technologies evaluated with the busbar cost method.

In total, it is recommended that nine of the 35 options be screened from further consideration in the full IRP modeling studies. This screening will help reduce model run time and focus on the options most likely to be cost-effective additions to BHP and CLFP expansion plans.

Table 1-1 Option Recommendations

OPTION NUMBER AND DESCRIPTION	BUSBAR PERFORMED (Y/N)	OTHER TYPE OF ANALYSIS	CARRY FORWARD?
Option 1: A 100 MW carbon capture addition to an existing 100 MW unit in Gillette (NS2).	Yes		Yes, initially
Option 2: A new 500 MW supercritical coal plant with carbon capture.	Yes		No
Option 3: A conversion of LM6000 CT to burn 30 percent - 50 percent hydrogen blend.	Yes		Yes
Option 4: An 80-100 MW coal to gas conversion unit.	Yes		Yes
Option 5: An 80-100 MW coal plant life extension.	Yes		Yes

OPTION NUMBER AND DESCRIPTION	BUSBAR PERFORMED (Y/N)	OTHER TYPE OF ANALYSIS	CARRY FORWARD?
Option 6: An 80-100 MW cold reserve unit.	No	Cold Reserve Cost Estimate	Yes, initially
Option 7: Convert CT1 (LM6000 PD) to 2x1 wet cooled combined cycle resource.	Yes		No
Option 8: Convert CT1 (LM6000 PD) to 2x1 dry cooled combined cycle resource.	Yes		No
Option 9: Convert CT2 (LM6000 PF) to 2x1 wet cooled combined cycle resource.	Yes		Yes
Option 10: Convert CT2 (LM6000 PF) to 2x1 dry cooled combined cycle resource.	Yes		Yes
Option 11: Convert 10 MW Ben French diesel unit to fire natural gas.	Yes		Yes
Option 12: A 10 MW battery – 4-hour lithium ion battery storage to replace diesels.	Yes		Yes
Option 13: A 1x1 7HA.02 combined cycle plant without duct-firing.	Yes		Yes
Option 14: A 3x1 LM6000 PF+ combined cycle plant without duct-firing.	Yes		Yes
Option 15: A 2x1 LM6000 PF+ combined cycle plant without duct-firing.	Yes		Yes
Option 16: A 2x1 LM6000 PF+ combined cycle plant without duct-firing at CPGS.	Yes		Yes
Option 17: A 1x1 LM6000 PF+ combined cycle plant with duct-firing.	Yes		No
Option 18: A 1x0 LMS100 simple cycle combustion turbine peaking unit.	Yes		Yes
Option 19: A 1x0 LM6000 PF+ simple cycle combustion turbine peaking unit.	Yes		Yes
Option 20: A 1x0 7EA simple cycle combustion turbine peaking unit.	Yes		No
Option 21: A 200 MW solar photovoltaic single axis tracking resource.	Yes		Yes
Option 22: A 100 MW solar photovoltaic single axis tracking resource.	Yes		Yes
Option 23: A 50 MW solar photovoltaic single axis tracking resource.	Yes		Yes
Option 24: A 200 MW wind resource.	Yes		Yes, 2 of 3 locations
Option 25: A 100 MW wind resource.	Yes		Yes, 2 of 3 locations

OPTION NUMBER AND DESCRIPTION	BUSBAR PERFORMED (Y/N)	OTHER TYPE OF ANALYSIS	CARRY FORWARD?
Option 26: A 50 MW wind resource.	Yes		Yes, 2 of 3 locations
Option 27: A 10 MW 4-hour lithium ion battery storage unit.	Yes		No
Option 28: A 30 MW 4-hour lithium ion battery storage unit.	Yes		Yes
Option 29: A 100 MW 4-hour lithium ion battery storage unit.	Yes		Yes
Option 30: A 200 MW 4-hour lithium ion battery storage unit.	Yes		Yes
Option 31: A 100 MW biofuels plant.	Yes		No
Option 32: A 40 MW geothermal plant.	Yes		No
Option 33: A 120 MW small scale modular reactor assumed to be available no sooner than 2030.	Yes		No
Option 34A-E: Cost to add 30-minute battery to each LM6000.	Yes		Yes, except 34C
Option 35: NS2 Retirement.	No	Retirement Cost Estimate	Yes

Table 1-2 Comprehensive Busbar Costs by Technology Group and Location

UNIT	BUSBAR COST					
Base Load Options	**CAPACITY FACTOR**					
Rapid City, South Dakota	40%	50%	60%	70%	80%	90%
Option 13SD: 444 MW - 1x1 7HA.02 CC w/o DF	8.22	7.39	6.83	6.43	6.14	5.90
Option 14SD: 167 MW - 3x1 LM6000 PF+ CC w/o DF	12.19	10.67	9.65	8.92	8.38	7.95
Option 15SD: 111 MW - 2x1 LM6000 PF+ CC w/o DF	12.96	11.30	10.20	9.41	8.82	8.36
Option 17SD: 73 MW - 1x1 LM6000 PF+ CC with DF	13.35	11.74	10.67	9.90	9.33	8.88
Gillette, Wyoming	40%	50%	60%	70%	80%	90%
Option 7: 102 MW – NSC CT1 (LM6000 PD) Convert to 2x1 Wet CC	10.52	9.32	8.52	7.95	7.53	7.19
Option 8: 101 MW – NSC CT1 (LM6000 PD) Convert to 2x1 Dry CC	10.84	9.59	8.76	8.17	7.72	7.37

UNIT	BUSBAR COST					
Option 1: 100 MW (90%) Carbon Capture System Installed at Existing 100 MW Unit in Gillette	22.27	18.25	15.57	13.66	12.22	11.11
Option 2: New 500 MW Supercritical Coal Plant with CO2 Capture	42.65	34.50	29.07	25.20	22.29	20.02
Option 4: 80-100 MW Coal to Gas Conversion Unit	8.98	8.61	8.36	8.19	8.05	7.95
Option 5: 80-100 MW Coal Plant Life Extension	12.16	10.09	8.71	7.73	6.99	6.41
Cheyenne, Wyoming	40%	50%	60%	70%	80%	90%
Option 9: 97 MW – CPGS CT2 (LM6000 PF) Convert to 2x1 Wet CC	10.03	8.79	7.96	7.36	6.92	6.57
Option 10: 96 MW – CPGS CT2 (LM6000 PF) Convert to 2x1 Dry CC	10.33	9.03	8.17	7.55	7.08	6.72
Option 13W: 444 MW - 1x1 7HA.02 CC w/o DF at CPGS	7.38	6.55	5.99	5.59	5.29	5.06
Option 14W: 167 MW - 3x1 LM6000 PF+ CC w/o DF at CPGS	11.25	9.72	8.71	7.98	7.43	7.01
Option 15W: 111 MW - 2x1 LM6000 PF+ CC w/o DF at CPGS	12.02	10.36	9.25	8.47	7.87	7.41
Option 16: 112 MW - 2x1 LM6000 PF+ CC w/o DF at CPGS	11.95	10.31	9.21	8.43	7.84	7.39
Option 17W: 73 MW - 1x1 LM6000 PF+ CC with DF at CPGS	12.30	10.69	9.62	8.86	8.28	7.83
Wyoming (City Unspecified)	40%	50%	60%	70%	80%	90%
Option 31: 100 MW Biofuel Plant	27.32	22.94	20.02	17.93	16.37	15.15
Option 32: 40MW Geothermal	34.65	27.72	23.10	19.80	17.32	15.40
Option 33: 100 MW SMR	22.90	18.52	15.61	13.52	11.96	10.75
Peaking Options	**CAPACITY FACTOR**					
Rapid City, South Dakota	5%	15%	25%	35%		
Option 11: Convert 10 MW Diesel to Natural Gas	19.78	11.19	9.47	8.73		
Option 18SD: 91 MW - 1x0 LMS100 CT	50.18	20.51	14.57	12.03		
Option 19SD: 42 MW - 1x0 LM6000 PF+ CT	63.49	25.38	17.76	14.50		
Option 20SD: 75 MW - 1x0 7EA CT	64.53	26.43	18.81	15.54		
Cheyenne, Wyoming	5%	15%	25%	35%		

UNIT	BUSBAR COST					
Option 3: Conversion of LM6000 CT to Burn 35% Hydrogen Blend	27.17	17.47	15.53	14.70		
Option 18W: 91 MW - 1x0 LMS100 CT	49.01	19.34	13.4	10.86		
Option 19W: 42 MW - 1x0 LM6000 PF+ CT	62.23	24.13	16.51	13.24		
Option 20W: 75 MW - 1x0 7EA CT	63.04	24.93	17.31	14.04		
Solar Options	**CAPACITY FACTOR**					
Gillette, Wyoming	**15.7%**	**18.7%**	**21.7%**			
Option 21GW: 200 MW Solar PV SAT	11.63	9.76	8.41			
Option 22GW: 100 MW Solar PV SAT	11.86	9.96	8.58			
Option 23GW: 50 MW Solar PV SAT	12.26	10.30	8.87			
Hot Springs, South Dakota	**18.6%**	**21.6%**	**24.6%**			
Option 21SD: 200 MW Solar PV SAT	9.81	8.45	7.42			
Option 22SD: 100 MW Solar PV SAT	10.01	8.62	7.57			
Option 23SD: 50 MW Solar PV SAT	10.35	8.91	7.83			
Cheyenne, Wyoming	**17.1%**	**20.1%**	**23.1%**			
Option 21CW: 200 MW Solar PV SAT	10.68	9.08	7.90			
Option 22CW: 100 MW Solar PV SAT	10.89	9.27	8.06			
Option 23CW: 50 MW Solar PV SAT	11.26	9.58	8.33			
Wind Options	**CAPACITY FACTOR**					
Cheyenne, Wyoming	**42.06%**	**45.06%**	**48.06%**			
Option 24CW: 200 MW Wind	5.14	4.80	4.50			
Option 25CW: 100 MW Wind	5.27	4.92	4.61			
Option 26CW: 50 MW Wind	5.34	4.98	4.67			
Gillette, Wyoming	**36.66%**	**39.66%**	**42.66%**			
Option 24GW: 200 MW Wind	5.90	5.46	5.07			
Option 25GW: 100 MW Wind	6.04	5.59	5.19			
Option 26GW: 50 MW Wind	6.12	5.66	5.26			
Douglas, Wyoming	**39.42%**	**42.42%**	**45.42%**			
Option 24DW: 200 MW Wind	5.49	5.10	4.76			
Option 25DW: 100 MW Wind	5.62	5.22	4.88			
Option 26DW: 50 MW Wind	5.69	5.29	4.94			

UNIT	BUSBAR COST					
BESS Options	(Cycles Per Day)					
Wyoming (City Unspecified)	0.5	1	2	(Cycles Per Day)		
Option 12: 10 MW 4-hr BESS as Diesel Replacement	47.60	25.07	13.81			
Option 27W: Stand Alone 4-hr BESS - 10 MW	47.60	25.07	13.81			
Option 28W: Stand Alone 4-hr BESS - 30 MW	44.44	23.49	13.02			
Option 29W: Stand Alone 4-hr BESS - 100 MW	41.26	21.90	12.22			
Option 30W: Stand Alone 4-hr BESS - 200 MW	39.55	21.05	11.79			
Option 34A: Add 30 min BESS to LM6000 - 137 MW	53.11	27.82	15.18			
Option 34B: Add 30 min BESS to LM6000 - 100 MW	54.19	28.37	15.45			
Option 34C: Add 30 min BESS to LM6000* - 100 MW	54.19	28.37	15.45			
Option 34D: Add 30 min BESS to LM6000 - 56 MW	56.25	29.40	15.97			
Option 34E-W: Add 30 min BESS to LM6000 - 40 MW	57.49	30.02	16.28			
South Dakota (City Unspecified)	0.5	1	2	(Cycles Per Day)		
Option 27SD: Stand Alone 4-hr BESS - 10 MW	48.46	25.93	14.66			
Option 28SD: Stand Alone 4-hr BESS - 30 MW	45.30	24.35	13.87			
Option 29SD: Stand Alone 4-hr BESS - 100 MW	42.12	22.76	13.08			
Option 30SD: Stand Alone 4-hr BESS - 200 MW	40.41	21.90	12.65			
Option 34E-SD: Add 30 min BESS to LM6000 - 40 MW	58.35	30.87	17.14			

Note* Option 34B is the 100MW LM6000 and Option 34C is the 100 MW LM6000 PF+.

2.0 Study Background and Economic Assumptions Required for the Busbar Evaluation

Black Hills Power, Inc. (BHP) and Cheyenne Light Fuel and Power Company (CLFP) are in the process of developing integrated resource plans (IRPs). The IRPs will evaluate the two service areas independently and on a combined basis. An IRP has as the objective the delivery of a safe and reliable power supply at the lowest reasonable cost, consistent with environmental and other objectives. An IRP involves a long-term planning horizon covering the next 15 to 30 years and requires a long-term demand forecast. To meet future demand, IRPs select capacity resources from a list of candidate supply side options and demand side options that could be part of the preferred expansion plan.

IRP studies and the identification of the preferred expansion plan normally involve detailed production costing and expansion planning models that model system operation on an hourly basis during the planning period. Commercial models such as PLEXOS, PROMOD, and Hitachi ABB Power Grids Capacity Expansion and Portfolio Optimization are well known examples of planning models used in the industry. These models identify when additional capacity is required to meet peak demand plus planning reserve requirements, and which supply side or demand side options are preferred from a cost, reliability, and environmental perspective.

The hourly simulation aspect of most planning models means it is very time consuming to evaluate an extensive list of candidate units directly in the model. Adding one or two options to an existing list of candidate units can exponentially increase computer simulation run times and optimization. To help eliminate candidate options that have little chance of being cost-effective and to reduce computer simulation time requirements, it is common to undertake a preliminary screening of candidate options. This is often in the form of a busbar cost evaluation screening tool.

A busbar model develops an all-in, levelized busbar cost of a candidate resource option over a period of time. The "all-in" refers to the presentation of both fixed (capital costs and fixed operating and maintenance (O&M) costs) and variable (fuel and variable O&M) costs on a $/MWh or cent/kWh basis. "Levelization" refers to the development of a single $/MWh or cent/kWh cost from the year-by-year busbar costs and can be thought of as a present value, average cost over the evaluation period. The term "busbar" refers to the inclusion of all costs incurred to deliver a kWh or MWh of electricity to the grid, measured at the high side of the step-up transformer. A more detailed explanation of the busbar model used in this study is presented in Section 3.0.

The busbar screening analysis can be performed using a spreadsheet tool such as Excel. The busbar model is much simpler that an expansion planning model because the busbar tool evaluates a single resource option across a range of capacity factors rather than dispatching all utility resources to serve load as is done in a production costing and expansion planning model. Nevertheless, the busbar model requires several economic and technical input assumptions. The economic assumptions used for the busbar analysis are described in the remainder of this section. The technical cost and performance inputs are described in Section 3.

2.1 BUSBAR EVALUATION PERIOD

A busbar evaluation period of 25 years is used for the analysis. The period of evaluation is 2021 through 2045. This period was selected because the cost estimates developed were 2021 cost estimates. This evaluation assumes the same commercial operation period to allow for an equal busbar comparison at the screening stage. (The more detailed IRP modeling to follow will evaluate the optimal timing of resource additions and will reflect the future cost impacts arising from inflation and allowance for funds used during construction (AFUDC) impacts).

2.2 INFLATION AND ESCALATION RATES

The general inflation rate, construction cost escalation rate, fixed O&M escalation rate, and nonfuel variable O&M escalation rate are all assumed to be 1.5 percent. This annual rate is applied to initial costs for use in deriving estimates of future year costs.

2.3 DEBT FINANCING ASSUMPTIONS

The analysis assumes that new unit additions will be financed with 47 percent debt. The debt is assumed to have an associated interest rate cost of 6.08 percent per year.

2.4 EQUITY FINANCING ASSUMPTIONS

The analysis assumes that new unit additions will be financed with 53 percent equity. The equity is assumed to have an associated rate of return of 9.25 percent.

2.5 WEIGHTED COST OF CAPITAL AND PRESENT WORTH DISCOUNT RATE

The present worth discount rate is assumed to equal 7.76 percent. The present worth discount rate is used to state all annual costs in the busbar analysis on a present value basis, which then allows the costs to be levelized.

2.6 LEVELIZED FIXED CHARGE RATE

The fixed charge rate, or FCR, represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year fixed charge rate because the levelized FCR is easier to apply than is a series of annual fixed charge rates.

Black & Veatch has a levelized fixed charge rate program that calculates the rate based on inputs that include debt and equity costs and ratios, book and tax life, income tax rate, and other optional cost components such as plant insurance and property taxes. For the busbar analysis, the cost of debt and equity plus the debt to equity ratio described in Section 2.3 through 2.5 were used along with the MACRS tax depreciation period shown in Table 2-1 for the various technologies listed. There is also an assumed tax rate of 21 percent and an additional charge of 0.38 percent for plant insurance. The resulting levelized fixed charge rates are shown in Table 2-1. For all options except the steam units and combined cycles options, which are assumed to recover capital costs over a 25-year period, the levelized fixed charge rates are applied over a 20-year period in the analysis.

Table 2-1 Levelized Fixed Charge Rate by Asset Type

ASSET TYPE	MACRS TAX DEPRECIATION PERIOD	LEVELIZED FIXED CHARGE RATE, PERCENT
Electric Utility Steam Unit (coal and combined cycle)	20	13.65
Electric Utility Nuclear Unit	15	14.41
Electric Utility Combustion Turbine and Diesel Units	15	14.41
Solar Facility	5	12.54
Wind Facility	5	12.54
Geothermal	5	12.54
Biofuel	7	13.92
BESS	7	13.92

2.7 FUEL PRICE FORECAST

Table 2-2 and

Table 2-3 list the fuel price forecast for the busbar analysis. Fuel prices are presented for natural gas at three locations (Cheyenne, Gillette, and Rapid City) and the forecasted coal price for Gillette is listed. There is also a column listing the assumed biomass fuel price to be used in the study.

Table 2-2 Busbar Fuel Price Forecasts, 2021-2045

YEAR	DELIVERED NG PRICE, CHEYENNE $/MMBTU	DELIVERED NG PRICE, GILLETTE $/MMBTU	DELIVERED NG PRICE, RAPID CITY $/MMBTU	DELIVERED COAL PRICE $/MMBTU[1]	DELIVERED BIOMASS PRICE $/MMBTU[2]
2021	3.21	4.08	4.34	0.87	3.13
2022	3.07	3.96	4.21	0.95	3.17
2023	3.43	4.33	4.61	0.96	3.22
2024	3.78	4.69	5.00	0.99	3.27
2025	4.04	4.96	5.28	1.07	3.32
2026	4.12	5.05	5.38	1.04	3.37
2027	4.11	5.06	5.39	1.04	3.42
2028	4.23	5.19	5.53	1.05	3.47
2029	4.27	5.25	5.59	1.07	3.52
2030	4.31	5.29	5.64	1.11	3.57
2031	4.47	5.47	5.82	1.10	3.63
2032	4.56	5.57	5.94	1.12	3.68
2033	4.64	5.67	6.04	1.13	3.74
2034	4.79	5.83	6.21	1.17	3.79
2035	5.09	6.14	6.54	1.17	3.85
2036	5.36	6.43	6.84	1.18	3.91
2037	5.66	6.74	7.18	1.20	3.97
2038	5.95	7.05	7.51	1.25	4.03
2039	6.15	7.27	7.74	1.24	4.09
2040	6.42	7.56	8.06	1.26	4.15
2041	6.67	7.82	8.33	1.28	4.21
2042	6.80	7.97	8.49	1.32	4.27
2043	6.99	8.18	8.71	1.31	4.34
2044	7.37	8.58	9.14	1.33	4.40
2045	7.77	9.00	9.59	1.35	4.47

1. Based on the $/ton fuel prices provided by BHP and an assumed heat content of 8,030 Btu per pound of coal, as received.
2. Based on the average of the range provided by the Department of Energy. This can vary widely based on the actual type of biomass.

Table 2-3 Busbar Fuel Price Forecasts, 2021-2045

YEAR	DELIVERED NUCLEAR PRICE $/MMBTU	DELIVERED BLENDED HYDROGEN AND NG PRICE, GILLETTE $/MMBTU[1]
2021	0.68	10.97
2022	0.69	11.13
2023	0.70	11.30
2024	0.71	11.47
2025	0.72	11.64
2026	0.73	11.82
2027	0.74	12.00
2028	0.75	12.17
2029	0.77	12.36
2030	0.78	12.54
2031	0.79	12.73
2032	0.80	12.92
2033	0.81	13.12
2034	0.83	13.31
2035	0.84	13.51
2036	0.85	13.72
2037	0.86	13.92
2038	0.88	14.13
2039	0.89	14.34
2040	0.90	14.56
2041	0.92	14.77
2042	0.93	15.00
2043	0.94	15.22
2044	0.96	15.45
2045	0.97	15.68

1. Assumption of $7/kg for the price of hydrogen.

2.8 OWNER'S COST

Black & Veatch assumed Owner's Costs to be 10 to 25 percent of capital costs depending upon the technology and plant configurations. Black & Veatch assumed a 10 percent Owner's Cost adder for coal plant and battery storage options, a 20 percent Owner's Cost adder for solar, wind, geothermal, biofuel, and the small modular reactor options, 22 percent for simple cycle options (including the Ben French units), and 25 percent for combined cycle options. Additional details regarding a list of possible Owner's Cost components are provided in Section 3.1.

3.0 Initial Candidate Technologies and Related Inputs

The busbar analysis requires a list of candidate technologies that are screened on an economic basis to determine if they should be carried forward to the detailed IRP modeling process. Based on input from BHP, the following list of candidate technologies was selected for analysis. To assist tracking the large number of options, the candidate options listed are given an option number that is used in the remainder of this report.

The initial technologies selected for this study include conventional technology options using natural gas or coal for fuel, the conversion of existing units to another fuel source or technology (for example, coal unit conversion to burn natural gas, or combustion turbine (CT) unit conversion to combined cycle (CC) operation), plus solar, wind, biofuel, and geothermal renewable energy options. The natural gas fired plants include distinctions such as PD, PF, or PF+.[1]

In addition, cost estimates were developed for selected battery energy storage system (BESS) options, carbon capture options, life extension and retirement options for the Neil Simpson 2 (NS2) coal plant, and advanced technologies such as small-scale nuclear reactor and the use of hydrogen blend fuel. For Option 1, the carbon capture technology addition to NS2, a 90 percent carbon capture reduction is achieved (from 2,800 lbs/MWh of CO2 to 362 lbs/MWh of CO2 with the carbon capture system). For Option 2, the carbon emissions rate is 2,187 lbs/MWh.

Following the general order of technologies in the scope of work, the options considered include:

Fossil Generation Carbon Capture Resource Options

- Option 1: A 100 MW carbon capture addition to an existing 100 MW unit in Gillette (NS2).
- Option 2: A new 500 MW supercritical coal plant with carbon capture.
- Option 3: A conversion of an LM6000 CT to burn a 30 percent to 50 percent hydrogen blend.

NS2 Coal Plant Options

- Option 4: Conversion of an 80-100 MW coal plant to burn natural gas.
- Option 5: Life extension projects for an 80-100 MW coal plant (recommended to reach a 2039 end of life date).
- Option 6: Placing an 80-100 MW coal unit into cold reserve.

LM6000 Unit Conversion to Combined Cycle Operation at Neil Simpson Complex (NSC) and Cheyenne Prairie Generating Station (CPGS)

- Option 7: Convert CT1 (LM6000 PD) to 2x1 wet cooled combined cycle resource.
- Option 8: Convert CT1 (LM6000 PD) to 2x1 dry cooled combined cycle resource.
- Option 9: Convert CT2 (LM6000 PF) to 2x1 wet cooled combined cycle resource.
- Option 10: Convert CT2 (LM6000 PF) to 2x1 dry cooled combined cycle resource.

[1] The PD, PF, and PF+ designations reflect advances in GE's LM6000 product line. The PD is an earlier version of the PF. The PD and the PF utilize dry-low emissions combustion systems, but the PF has slightly better performance as a newer, improved product. The PF+ is a further refined version of the PF. The PF+ includes an increase change in output because the machine rotates at a higher speed and can push more mass through the unit. The PD and PF operate at 3,600 rpm and the PF+ operates at 3,910 rpm.

Black Hills Energy Ready

Existing Ben French Diesel Generators Conversion Resource Options

- Option 11: Convert the 10 MW Ben French diesel unit to fire natural gas.
- Option 12: A 10 MW battery – 4-hour lithium ion battery storage to replace diesels.

Other Resource Options (wind, solar, battery storage, modular nuclear, biofuel, NG fired)

- Option 13: A 1x1 7HA.02 combined cycle plant without duct-firing.
- Option 14: A 3x1 LM6000 PF+ combined cycle plant without duct-firing.
- Option 15: A 2x1 LM6000 PF+ combined cycle plant without duct-firing.
- Option 16: A 2x1 LM6000 PF+ combined cycle plant without duct-firing at CPGS.
- Option 17: A 1x1 LM6000 PF+ combined cycle plant with duct-firing.
- Option 18: A 1x0 LMS100 simple cycle combustion turbine peaking unit.
- Option 19: A 1x0 LM6000 PF+ simple cycle combustion turbine peaking unit.
- Option 20: A 1x0 7EA simple cycle combustion turbine peaking unit.
- Option 21: A 200 MW solar photovoltaic single axis tracking resource.
- Option 22: A 100 MW solar photovoltaic single axis tracking resource.
- Option 23: A 50 MW solar photovoltaic single axis tracking resource.
- Option 24: A 200 MW wind resource.
- Option 25: A 100 MW wind resource.
- Option 26: A 50 MW wind resource.
- Option 27: A 10 MW 4-hour lithium ion battery storage unit.
- Option 28: A 30 MW 4-hour lithium ion battery storage unit.
- Option 29: A 100 MW 4-hour lithium ion battery storage unit.
- Option 30: A 200 MW 4-hour lithium ion battery storage unit.
- Option 31: A 100 MW biofuels plant.
- Option 32: A 40 MW geothermal plant.
- Option 33: A 120 MW small scale modular reactor assumed to be available no sooner than 2030

Ancillary Service Support Resource Option

- Option 34A-E: Cost to add 30-minute battery to each LM6000

Other

- Option 35: NS2 Retirement

3.1 OPTION CAPITAL COST AND CAPACITY ESTIMATES

Capital cost estimates were developed for each candidate option. Capital costs refer to the initial investment cost to engineer, procure, and construct a facility, commonly referred to as a facility's EPC cost, plus other costs that are not typically included in an EPC cost that must be accounted for by the facility owner (Owner's Cost).

There are many potential cost items that can be included as an Owner's Cost, depending on whether the project is an independent power producer (IPP) project or utility-owned. Table 3-1 provides a listing of costs that can be part of the Owner's Cost category.

Table 3-1 List of Possible Owner's Cost Components

POSSIBLE OWNER'S COST	COMPONENT BREAKDOWN
Project Development	• Site selection study • Land purchase/options/rezoning • Landscaping • Transmission/gas pipeline rights-of-way • Off-site road modifications/upgrades • Demolition (if applicable) • Air quality & other environmental permitting/offsets • Public relations/community development • Legal assistance
Utility Interconnections	• Natural gas service (if applicable) • Gas system upgrades (if applicable) • Electrical transmission • Water supply • Wastewater/sewer (if applicable) • Water service extensions
Spare Parts and Plant Equipment	• Air quality control systems (AQCS) materials, supplies, and parts • Turbine and reciprocating engine materials, supplies, and parts • BOP equipment materials, supplies, and parts • Rolling stock • Plant furnishings and supplies • Operating spares
Owner's Project Management	• Preparation of bid documents and selection of contractors and suppliers • Provision of project management • Performance of engineering due diligence • Provision of Owner's personnel for site construction management
Plant Startup/Construction Support	• Owner's site mobilization • O&M staff training • Supply of trained operators to support equipment testing and commissioning • Initial test fluids and lubricants • Initial inventory of chemicals/reagents • Consumables/startup spares • Cost of fuel not recovered in power sales • Construction power • Construction all-risk insurance • Acceptance testing

POSSIBLE OWNER'S COST	COMPONENT BREAKDOWN
Taxes/Advisory Fees/Legal	• Taxes • Market and environmental consultants • Operating insurance • Owner's legal expenses: o Power Purchase Agreement (PPA) o Interconnect agreements o Contracts--procurement and construction o Property transfer
Owner's Contingency	• Owner's uncertainty and costs pending final negotiation: o Unidentified project scope increases o Unidentified project requirements o Costs pending final agreement (e.g., interconnection contract costs) • Construction claims
Financing	• Development of financing sufficient to meet project obligations or obtaining alternate sources of funding • Allowance for Funds Used During Construction (AFUDC) • Financial advisor, lender's legal, market analyst, and engineer • IDC • Loan administration and commitment fees • Debt service reserve fund
Miscellaneous	• All costs for above-mentioned contractor-excluded items, if applicable

For many projects, the largest single Owner's Cost component is the interest during construction (IDC); for regulated utilities utilizing debt and equity as sources of funds, the term used is allowance for funds used during construction (AFUDC). The IDC and AFUDC costs account for the time value of money on debt and equity funds that accrue between the drawdown of funds during construction, which are used to pay the EPC contractor and various Owner's Costs, and the commercial operation date. Thus, other things being equal, a project having a longer construction period will have higher IDC or AFUDC costs.

For projects in advanced planning stage, a month-by-month drawdown amount during construction is estimated and the IDC or AFUDC amount is calculated from the month of drawdown to the commercial operation date. For planning studies in which a monthly drawdown calculation does not occur for each option, it is common to use a more simplified process. One approach commonly used to calculate IDC or AFUDC in planning studies is referred to as the mid-point, overnight construction process. In this process, the EPC and other Owner's Costs are escalated at the assumed inflation rate to the mid-point of construction and then the IDC or AFUDC rate is applied from the mid-point of construction to the commercial operations date. This method provides satisfactory results when month-by-month drawdown amounts are not available. In this study no specific IDC or AFUDC amount was calculated because the assumed commercial operations date is assumed to be 2021 for the options, which allows all options to be compared on an equal timeframe basis. IDC or AFUDC costs are assumed to be part of the overall Owner's Cost percentage that is added to the EPC cost. As the IRP advances and specific in-service dates for selected options are known, more precise estimates of AFUDC costs for BHP and CLFP can be made.

The EPC cost plus Owner's Cost components equal the project total capital cost. In this study, the busbar cost table will indicate these capital cost components and will show the yearly charge to recover the capital costs using the levelized fixed charge rate.

Table 3-2 through Table 3-7 present capital costs information and net output information for the options studied in this report. This information allows the capital costs to be stated in terms of the capital cost per kW of net capacity in current year (2021) dollars. A brief description is provided before each table.

Table 3-2 presents capital cost, net output, and $/kW capital costs for Option 1 through Option 3, consisting of two carbon capture and the conversion of an existing gas-fired LM6000 CT to burn 30 to 50 percent hydrogen and natural gas fuel mix. Option 1 and Option 3 do not involve new facilities but the conversion of existing facilities to reduce emissions through carbon capture (Option 1) or burning a blend of hydrogen (Option 3). Option 2 is a new supercritical coal plant that is highly efficient and includes carbon capture technology. Both carbon capture systems assume a 90 percent capture rate for carbon capture efficiency.

Table 3-2 Candidate Unit Output and Capital Cost – Carbon Capture Options

CAPACITY OPTION	NET OUTPUT, MW	2021 EPC CAPITAL COST ($/KW)	2021 OWNER'S COST ($/KW)	TOTAL 2021 IN-SERVICE CAPITAL COST ($000S)	2021 $ PER NET KW
Option 1: 100 MW carbon capture addition to existing 100 MW units in Gillette (NS2)	68 (80 MW before adding carbon capture)	$4,206	$421	$314,600	$4,626
Option 2: New supercritical coal plant with carbon capture	380	5,842	$2,628	$3,854,418	$8,470
Option 3: Conversion of LM6000 CT to burn 30 percent - 50 percent hydrogen blend	42 (42MW before adding hydrogen blend)	$92	$20	$4,704	$112
Notes: Capital costs are stated in beginning of year, 2021 dollars.					

Table 3-3 includes capital cost and output information for three options involving a coal facility sized similar to the NS2 unit (79 MW). Options 4 through Option 6 are not new facilities but involve the conversion of an existing coal facility to burn natural gas (Option 4), an investment to extend the operating life of an existing coal facility (Option 5), and the investment needed to put the coal unit into cold reserve (Option 6), meaning that it is not a candidate for near-term dispatch, but can be brought back into service if needed.

Note that while Option 5 is called a life extension project, it really consists of recommended projects identified by Black & Veatch to allow the coal unit to safely and reliably operate until the published retirement date of 2039. The recommended projects are over and above those capital renewal and replacement (R&R) projects already planned by the owner in Black Hills' NS2 five-year (2021-2026) capital budget forecast and future (2027-2029) capital R&R not in the long-term forecast.

Option 6, putting the coal unit into cold reserve, does not have output and capital costs listed because all the costs developed by Black & Veatch are classified as an annual fixed O&M cost as the unit is taken out of service but allowing for the possibility that the unit could restart and operate in the future. This fixed O&M cost is provided in Section 3.2.

Table 3-3 Candidate Unit Output and Capital Cost – Coal Plant Options

CAPACITY OPTION	NET OUTPUT, MW	2021 EPC CAPITAL COST ($/KW)	2021 OWNER'S COST ($/KW)	TOTAL 2021 IN-SERVICE CAPITAL COST ($000S)	2021 $ PER NET KW
Option 4: 80-100 MW coal to gas conversion unit	79	$102	$9	$9,845	$111
Option 5: 80-100 MW coal plant life extension	80	$2,050	$228	$182,696	$2,278
Option 6: 80-100 MW cold reserve unit	N/A	N/A	N/A	N/A	N/A
Notes: Capital costs are stated in beginning of year, 2021 dollars.					

Table 3-4 includes capital cost and net output information for gas-fired base load options selected for inclusion in this study. The options include new gas-fired CT and CC options, as well as CT unit conversion to CC operation. The candidate options also include the use of wet cooling as well as dry cooling, which would result in lower water consumption. Some options also include the use of duct firing (DF), which consists of additional gas burners in the unit heat recover steam generator (HRSG) that increases the overall unit capacity beyond the output linked only to the waste heat captured from gas turbines.

Table 3-4 Candidate Unit Output and Capital Cost – Base Load Options

CAPACITY OPTION	NET OUTPUT, MW*	2021 EPC CAPITAL COST ($/KW)	2021 OWNER'S COST ($/KW)	TOTAL 2021 IN-SERVICE CAPITAL COST ($000S)	2021 $ PER NET KW
Option 7: NSC CT1 (LM6000 PD) conversion to 2x1 wet cooled combined cycle	102	$964	$241	$122,910	$1,205
Option 8: NSC CT1 (LM6000 PD) conversion to 2x1 dry cooled combined cycle	101	$1,009	$252	$127,361	$1,261
Option 9: CPGS CT2 (LM6000 PF) conversion to 2x1 wet cooled combined cycle	97	$1,013	$253	$122,899	$1,267
Option 10: CPGS CT2 (LM6000 PF) conversion to 2x1 dry cooled combined cycle	96	$1,062	$265	$127,329	$1,327
Option 13: 1x1 7HA.02 combined cycle plant without duct-firing	444	$791	$198	$439,116	$989
Option 14: 3x1 LM6000 PF+ combined cycle plant without duct-firing	167	$1,380	$345	$288,242	$1,726
Option 15: 2x1 LM6000 PF+ combined cycle plant without duct-firing	111	$1,455	$364	$201,798	$1,818
Option 16: CPGS 2x1 LM6000 PF+ combined cycle plant without duct-firing	112	$1,442	$360	$201,824	$1,802
Option 17: 1x1 LM6000 PF+ combined cycle plant with duct-firing	73	$1,318	$330	$120,304	$1,648

Notes: Capital costs are stated in beginning of year, 2021 dollars.
NSC is the Neil Simpson Complex in Gillette, WY and CPGS is the Cheyenne Prairie Generating Station in Cheyenne, WY.
*Net output is based on elevation levels provided by BH in annual average conditions: Annual average conditions: NSC 4,410ft, 64.2F Dry Bulb, 47.8F Wet Bulb - CPGS 5,837ft, 60F Dry Bulb, 38F Wet Bulb - Generic Greenfield 6,000ft, 60F Dry Bulb, 38F Wet Bulb.

Table 3-5 includes capital cost and net output information for peaking options selected for this study. Generally, peaking option generally operate a limited number of hours per year, usually less than 30 percent of the time, due to relatively high operating costs versus baseload units. The high operating costs are typically the result of relatively high fuel costs or a high net plant heat rate (NPHR), measured in Btu/kWh. Other typical characteristics of peaking options include a relatively small size compared to many baseload options, and a relatively low capital cost/kW relative to baseload options. In Table 3-5, three simple cycle options and the conversion of an existing diesel unit to burn natural gas are listed.

Table 3-5 Candidate Unit Output and Capital Cost – Peaking Options

CAPACITY OPTION	NET OUTPUT, MW	2021 EPC CAPITAL COST ($/KW)	2021 OWNER'S COST ($/KW)	TOTAL 2021 IN-SERVICE CAPITAL COST ($000S)	2021 $ PER NET KW
Option 11: Convert 10 MW Ben French diesel unit to fire natural gas	7.5	$350	$77	$3,203	$427
Option 18: 1x0 LMS100 simple cycle combustion turbine	91	$1,082	$238	$120,120	$1,320
Option 19: 1x0 LM6000 PF+ simple cycle combustion turbine	42	$1,249	$275	$64,008	$1,524
Option 20: 1x0 7EA simple cycle combustion turbine	75	$1,249	$275	$114,300	$1,524
Notes: Capital costs are stated in beginning of year, 2021 dollars.					

Table 3-6 lists several renewable energy options selected for the study. These renewable options include solar and wind technologies, as well as a biomass option. Due to economy of scale benefits, the cost per installed kW decreases slightly for the same technology as the size of a project increases, as seen in the data for the selected solar and wind options. It should also be noted that the biofuels and geothermal facility are considered generic in nature and would require significant additional work to identify viable site locations.

Table 3-6 Candidate Unit Output and Capital Cost – Renewable Options

CAPACITY OPTION	NET OUTPUT, MW	2021 EPC CAPITAL COST ($/KW)	2021 OWNER'S COST ($/KW)	TOTAL 2021 IN-SERVICE CAPITAL COST ($000S)	2021 $ PER NET KW
Option 21: 200 MW Solar PV SAT	200	$1,101	$220	$264,200	$1,321
Option 22: 100 MW Solar PV SAT	100	$1,124	$225	$134,900	$1,349
Option 23: 50 MW Solar PV SAT	50	$1,164	$233	$69,850	$1,397
Option 24: 200 MW Wind	200	$1,125	$225	$270,200	$1,351
Option 25: 100 MW Wind	100	$1,142	$228	$137,100	$1,371
Option 26: 50 MW Wind	50	$1,144	$229	$68,650	$1,373
Option 31: 100 MW biofuels plant	100	$4,080	$816	$489,600	$4,896
Option 32: 40 MW Geothermal	40	$7,146	$1,429	$343,040	$8,576

Notes: Capital costs are stated in beginning of year, 2021 dollars.

Table 3-7 contains several estimates of energy storage options utilizing the BESS technology. While there are many technologies for energy storage, the BESS has become a favored option in recent years and the BESS technology utilizing lithium-ion batteries constitute the most viable energy storage solution for power applications (the batteries utilize the same battery chemistry used in electric vehicles (EV)). The use of lithium-ion batteries in electric utility and EV applications continues to facilitate technological advances and reduction in costs due to economy of scale benefits. In recent years, due to the near instantaneous dispatch characteristics, BESS technology has been increasingly recognized as a cost-effective means of providing ancillary services, especially frequency regulation, plus the equivalent of spinning and non-spinning reserves.

Two general classes of BESS were used on this Bus Bar Study Project. The first class consists of, "power" BESS systems. These are BESS with 1 hour or less of storage duration. Generally, for this study, a 30-minute BESS was specified. Based on the dynamics of BESS operation, for the purposes of this study, an amount of energy storage was assumed to be installed at the beginning of the project (beginning of life, BOL) such that, when accounting for the decrease of capacity over time, the BESS unit would be able to provide the specified storage levels even at the end of the facility life (EOL), nominally 20 years for the BESS configurations developed.

Second, costs for "energy" BESS systems were also developed for the study. Energy BESS systems typically have longer storage durations and may be designed to provide a targeted level of energy over 2 hours to 4 hours. As with the power BESS systems, the initial capacity installed for the energy BESS systems was sized to provide the Black Hills the specified performance throughout the lifetime of the facility (nominally 20 years.)

Table 3-7 Candidate Unit Output and Capital Cost – BESS Options

CAPACITY OPTION	NET OUTPUT, MW	2021 EPC CAPITAL COST ($ PER NAMEPLATE KWH)	2021 OWNER'S COST ($ PER NAMEPLATE KWH)	TOTAL 2021 IN-SERVICE CAPITAL COST ($000S)	2021 $ PER NAMEPLATE KWH
Option 12: 10 MW 4-hr BESS as Diesel Replacement	10	$255	$28	$21,225	$283
Option 27: Stand Alone 4-hr BESS – 10 MW	10	$255	$28	$21,225	$283
Option 28: Stand Alone 4-hr BESS – 30 MW	30	$235	$26	$58,703	$261
Option 29: Stand Alone 4-hr BESS – 100 MW	100	$215	$24	$178,997	$239
Option 30: Stand Alone 4-hr BESS – 200 MW	200	$204	$23	$340,095	$227
Option 34A: Add 30 min BESS to LM6000 – 137 MW	137	$290	$32	$41,294	$322
Option 34B and 34C: Add 30 min BESS to LM6000 – 100 MW	100	$297	$33	$30,852	$330
Option 34D: Add 30 min BESS to LM6000 – 56 MW	56	$310	$34	$18,035	$344
Option 34E: Add 30 min BESS to LM6000 – 40 MW	40	$317	$35	$13,207	$353
Notes: Capital costs are stated in beginning of year, 2021 dollars.					

Table 3-8 lists the capital cost estimate for a small-scale modular reactor. For this analysis, it is assumed that the technology will be available by 2030. The capital cost estimate includes an estimated $40 million up-front cost for decommissioning that is assumed to be held in escrow until the unit is retired.

Table 3-8 Candidate Unit Output and Capital Cost – New Technology Options

CAPACITY OPTION	NET OUTPUT, MW	2021 EPC CAPITAL COST ($/KW)	2021 OWNER'S COST ($/KW)*	TOTAL 2021 IN-SERVICE CAPITAL COST ($000S)*	2021 $ PER NET KW*
Option 33: 100 MW Small-Scale Modular Reactor	100	$3,782	$756	$453,800	$4,538
Notes: Capital costs are stated in beginning of year, 2021 dollars. *The owner's cost (and total capital cost) of Option 33 include a decommissioning prepayment of $40 million. The prepayment was considered part of the owner's cost for this model. It is typically held in trust/investment account until decommissioning.					

3.2 O&M COST ESTIMATES

Table 3-9 through Table 3-15 present the net plant heat rate (NPHR) assumptions for the study, expressed as the Btu required to produce a net kWh of energy (Btu/kWh), along with the operation and maintenance costs.

The O&M cost estimates were developed based on O&M estimating models and representative estimates for similar projects. The costs utilize vendor estimates and recommendations, estimated performance information, and representative costs for staff wages, materials, consumables and supplies.

Black & Veatch has divided the O&M costs into two primary categories: fixed costs and variable costs. Fixed costs, presented in dollars per unit of net capacity per year ($/kW-yr), do not vary directly with plant power generation. These consist primarily of wages and wage-related overheads for the permanent plant staff, routine equipment maintenance, and other fixed costs. Variable costs, presented in dollars per unit of net annual generation ($/MWh), tend to vary in proportion to the output of the plant. Variable O&M include costs associated with equipment outage maintenance, chemicals, reagents, utilities, and other consumables. Fuel costs (as applicable) vary without output but are determined separately and are not included in the variable O&M costs.

Table 3-9 presents the NPHR data for three emission reduction options. The carbon capture conversion option shows a NPHR of 11,780 Btu/kWh. This compares to a NPHR before carbon capture of 9,819 Btu/kWh. Similarly, the Option 3 hydrogen blend NPHR of 9,400 Btu/kWh, which is the same as the current NPHR of 9,400 Btu/kWh.

Table 3-9 Candidate Unit Net Plant Heat Rate and O&M Costs – Carbon Capture Options

CAPACITY OPTION	FULL LOAD NET PLANT HEAT RATE (BTU/KWH, HHV)	FIXED O&M, 2021 $/KW-YR	VARIABLE O&M,	
			WITH MAJOR MAINTENANCE, 2021 $/MWH	WITHOUT MAJOR MAINTENANCE 2021 $/MWH
Option 1: 100 MW carbon capture addition to existing 100 MW units in Gillette (NS2).	11,780(9,819 Btu/kWh before adding carbon capture)	63.9*	7.97*	N/A
Option 2: New supercritical coal plant with carbon capture.	11,142	37.2	N/A	6.37
Option 3: Conversion of LM6000 CT to burn 30 percent - 50 percent hydrogen blend.	9,400 (9,400 Btu/kWh before adding hydrogen blend)	43	7.8	1.0

Notes:
Full load net plant heat rate is stated at average ambient conditions and represents higher heating value (HHV).
*O&M estimates for Option 1 are based upon 68 MW of net output with carbon capture versus 80 MW net output rating without carbon capture.

Table 3-10 presents the NPHR and O&M cost information for three NS2 options. For Option 6, the fixed O&M estimate included all costs for maintaining the coal plant while it is in cold reserves.

Table 3-10 Candidate Unit Net Plant Heat Rate and O&M Costs – Coal Plant Options

CAPACITY OPTION	FULL LOAD NET PLANT HEAT RATE (BTU/KWH, HHV)	FIXED O&M, 2021 $/KW-YR	VARIABLE O&M	
			WITH MAJOR MAINTENANCE, 2021 $/MWH	WITHOUT MAJOR MAINTENANCE 2021 $/MWH
Option 4: 80-100 MW coal to gas conversion unit	12,744	41.9	1.8	1.55
Option 5: 80-100 MW coal plant life extension	13,204	45.5	3.42	N/A
Option 6: 80-100 MW cold reserve unit	N/A	12.04	N/A	N/A
Notes: Full load net plant heat rate is stated at average ambient conditions and represents higher heating value (HHV).				

Table 3-11 presents NPHR and O&M estimates for conventional base load options. The NPHR numbers for these options reflect the highly efficient nature of current combined cycle technology, with options utilizing dry cooling slightly higher than the wet cooling counterpart and with CT to CC conversion options having a higher NPHR than new build options.

Table 3-11 Candidate Unit Heat Rate and O&M Costs – Base Load Options

CAPACITY OPTION	FULL LOAD NET PLANT HEAT RATE (BTU/KWH, HHV)	FIXED O&M, 2021 $/KW-YR	VARIABLE O&M	
			WITH MAJOR MAINTENANCE, 2021 $/MWH	WITHOUT MAJOR MAINTENANCE 2021 $/MWH
Option 7: NSC CT1 (LM6000 PD) conversion to 2x1 wet cooled combined cycle	7,200	40	5.4	1.1
Option 8: NSC CT1 (LM6000 PD) conversion to 2x1 dry cooled combined cycle	7,350	41	5.3	0.9
Option 9: CPGS CT2 (LM6000 PF) conversion to 2x1 wet cooled combined cycle	7,150	40	5.4	1.1
Option 10: CPGS CT2 (LM6000 PF) conversion to 2x1 dry cooled combined cycle	7,250	41	5.3	0.9
Option 13: 1x1 7HA.02 combined cycle plant without duct-firing	6,300	10	3.5	0.8
Option 14: 3x1 LM6000 PF+ combined cycle plant without duct-firing	7,050	28	4.2	1.0
Option 15: 2x1 LM6000 PF+ combined cycle plant without duct-firing	7,050	37	5.2	1.1
Option 16: CPGS 2x1 LM6000 PF+ combined cycle plant without duct-firing	7,050	37	5.2	1.1
Option 17: 1x1 LM6000 PF+ combined cycle plant with duct-firing	7,850	50	6.7	1.1
Notes: Full load net plant heat rate is stated at average ambient conditions and represents higher heating value (HHV).				

Table 3-12 lists NPHR and O&M costs for peaking options. The NPHR figures are high compared to the base load options in the previous table and this characteristic is the most important feature that determines the likely dispatch as a peaking resource.

Table 3-12 Candidate Unit Heat Rate and O&M Costs – Peaking Options

CAPACITY OPTION	FULL LOAD NET PLANT HEAT RATE (BTU/KWH, HHV)	FIXED O&M, 2021 $/KW-YR	VARIABLE O&M	
			WITH MAJOR MAINTENANCE, 2021 $/MWH	WITHOUT MAJOR MAINTENANCE 2021 $/MWH
Option 11: Convert 10 MW Ben French diesel unit to fire natural gas	11,900	No Change*	No Change*	No Change*
Option 18: 1x0 LMS100 simple cycle combustion turbine	8,750	18	5.3	0.9
Option 19: 1x0 LM6000 PF+ simple cycle combustion turbine	9,400	43	7.8	1.0
Option 20: 1x0 7EA simple cycle combustion turbine	11,200	43	7.8	1.0

Notes:
Full load net plant heat rate is stated at average ambient conditions and represents higher heating value (HHV).
*There is no change to the provided diesel O&M values based on a conversion to natural gas.

Table 3-13 presents NPHR and O&M cost information for the renewable technology options. Solar and wind options have no fuel cost or NPHR, and all O&M is placed into fixed O&M for these options.

Table 3-13 Candidate Unit Heat Rate and O&M Costs – Renewable Options

CAPACITY OPTION	FULL LOAD NET PLANT HEAT RATE (BTU/KWH, HHV)	FIXED O&M, 2021 $/KW-YR	VARIABLE O&M, 2021 $/MWH
Option 21: 200 MW Solar PV SAT	N/A	7	N/A
Option 22: 100 MW Solar PV SAT	N/A	7	N/A
Option 23: 50 MW Solar PV SAT	N/A	7	N/A
Option 24: 200 MW Wind	N/A	41	N/A
Option 25: 100 MW Wind	N/A	32	N/A
Option 26: 50 MW Wind	N/A	34	N/A
Option 31: 100 MW biofuels plant	13,700	125	4.8
Option 32: 40 MW Geothermal	N/A	200	N/A

Notes:
Full load net plant heat rate is stated at average ambient conditions and represents higher heating value (HHV).

Table 3-14 presents the O&M cost information for the BESS options and also lists the power and energy ratings for the options. In place of a NPHR, as presented for other options, the BESS information is stated in terms of the power (MW) and energy (MWh) ratings of the configuration. The variable O&M cost is the assumed $/kWh cost of purchasing power from the grid to recharge the BESS after discharge. The energy purchase price is based on Black & Veatch wholesale market estimates of energy prices for Wyoming and South Dakota.

Table 3-14 Candidate Unit Heat Rate and O&M Costs – BESS Options

CAPACITY OPTION	BESS POWER AND ENERGY RATINGS (MW, MWH)(A)	FIXED O&M, 2021 $/KWH-YR*	1ST YEAR VARIABLE O&M CHARGING COST, 2021 $/KWH**
Option 12: 10 MW 4-hr BESS as Diesel Replacement	10 MW, 40 MWh	7.5	0.01657
Option 27W: Stand Alone 4-hr BESS – 10 MW in Wyoming	10 MW, 40 MWh	7.5	0.01657
Option 27SD: Stand Alone 4-hr BESS – 10 MW in South Dakota	10 MW, 40 MWh	7.5	0.028293
Option 28W: Stand Alone 4-hr BESS – 30 MW in Wyoming	30 MW, 120 MWh	7.5	0.01657
Option 28SD: Stand Alone 4-hr BESS – 30 MW in South Dakota	30 MW, 120 MWh	7.5	0.028293
Option 29W: Stand Alone 4-hr BESS – 100 MW in Wyoming	100 MW, 400 MWh	7.5	0.01657
Option 29SD: Stand Alone 4-hr BESS – 100 MW in South Dakota	100 MW, 400 MWh	7.5	0.028293
Option 30W: Stand Alone 4-hr BESS – 200 MW in Wyoming	200 MW, 800 MWh	7.5	0.01657
Option 30SD: Stand Alone 4-hr BESS – 200 MW in South Dakota	200 MW, 800 MWh	7.5	0.028293
Option 34A: Add 30 min BESS to LM6000 – 137 MW	137 MW, 68.5 MWh	7.5	0.01657
Option 34B and 34C: Add 30 min BESS to LM6000 – 100 MW	100 MW, 50 MWh	7.5	0.01657
Option 34D: Add 30 min BESS to LM6000 – 56 MW	56 MW, 28 MWh	7.5	0.01657
Option 34E-W: Add 30 min BESS to LM6000 – 40 MW in Wyoming	40 MW, 20 MWh	7.5	0.01657
Option 34E-SD: Add 30 min BESS to LM6000 – 40 MW in South Dakota	40 MW, 20 MWh	7.5	0.028293

Notes:
*The Fixed O&M is calculated by taking the $/kWh-yr value and multiplying it by kW of output, output per cycle, and number of cycles per day.
**The Variable O&M is calculated by taking the $/kWh charging cost and multiplying it by the kWh purchased per cycle, number of cycles per day and number of days in the year.

Table 3-15 shows the O&M costs for the small-scale nuclear unit. Nuclear power plants do not have typical heat rates as the energy from the fuel is defined differently than other fossil plants.

Table 3-15 Candidate Unit Heat Rate and O&M Costs – Advanced Technology Options

CAPACITY OPTION	FULL LOAD NET PLANT HEAT RATE (BTU/KWH, HHV)	FIXED O&M, 2021 $/KW-YR	VARIABLE O&M, 2021 $/MWH*
Option 33: 100 MW Small Scale Modular Reactor	10,500	100	3
Notes: Full load net plant heat rate is stated at average ambient conditions and represents higher heating value (HHV).			

3.3 OTHER COST AND PERFORMANCE DATA FOR IRP MODELING

The cost and performance data presented in Section 3.1, 3.2 and Section 2 contains the essential input assumption information needed to perform the busbar analysis. For the more detailed IRP production costing and expansion planning modeling, additional detail will be required. For example, while the busbar analysis assumes operation at full load output, the detailed IRP model will be able to dispatch a unit at part load and as a result requires additional unit information. Table 3-16 includes more detailed information prepared by Black & Veatch for this assignment. Note that there are several qualifying assumptions and descriptions provided at the bottom of the table. Table 3-17 includes more detailed information prepared by Black & Veatch on the BESS options for this assignment. In these tables, the option numbering matches the list provided in Section 3.0.

Table 3-16 Black Hills Power and Cheyenne Light Fuel and Power Busbar Screening Option Characteristics Table

		1	2	3	4	5	6	7	8	9	10
Requested Characteristics for Natural Gas	**Description**	**100 MW CO2 capture addition to existing 100 MW units**	**New supercritical coal plant with CO2 capture**	**LM6000 Conversion to 35% Hydrogen (Note 9)**	**80-100 MW coal to gas conversion unit**	**80-100 MW coal plant life extension**	**80-100 MW cold reserve unit (Note 10)**	**NSC CT1 (LM6000 PD) CCCT Convert Wet**	**NSC CT1 (LM6000 PD) CCCT Convert Dry**	**CPGS CT2 (LM6000 PF) CCCT Convert Wet**	**CPGS CT2 (LM6000 PF) CCCT Convert Dry**
Gross Output	MW	90	500	43	90	90	N/A	105	103	100	99
Nominal Net Output	MW	68	380	42	79	80	N/A	102	101	97	96
Nominal Net Heat Rate	Btu/kWh-HHV	10,604	11,142	9,400	12,744	13,204	N/A	7,200	7,350	7,150	7,250
Greenfield/Brownfield	-	Brownfield	Brownfield	Brownfield	Brownfield	Brownfield	N/A	Brownfield	Brownfield	Brownfield	Brownfield
Capacity Factor (Note 7)	%/yr	80%	80%	30%	80%	180%	N/A	80%	80%	80%	80%
Turnkey EPC Cost (Note 1)	2021$/kW	4,206	5,842	92	102	2,050	N/A	964	1,009	1,013	1,062
Owner's Cost (Note 1)	2021$/kW	421	2,628	20	9	228	N/A	241	252	253	265
Total Investment Cost (Notes 1, 2)	2021$/kW	4,626	8,470	112	111	2,278	12.04	1,205	1,261	1,267	1,327
Annual Average MAX Load (Notes 3, 4, 5)	MW	68	500	42	79	80	N/A	102	101	97	96
Annual Average MID Load (Notes 3, 4, 5)	MW	Note 11	Note 11	31	Note 11	Note 11	N/A	88	87	76	74
Annual Average MIN Load (Notes 3, 4, 5)	MW	Note 11	Note 11	21	Note 11	Note 11	N/A	75	74	54	53
Annual Average MAX Load Heat Rate (Notes 3, 4, 5)	Btu/kWh-HHV	11,780	11,142	9,400	12,744	13,204	N/A	7,200	7,350	7,150	7,250
Annual Average MID Load Heat Rate (Notes 3, 4, 5)	Btu/kWh-HHV	Note 11	Note 11	10,250	Note 11	Note 11	N/A	7,450	7,600	7,400	7,500
Annual Average MIN Load Heat Rate (Notes 3, 4, 5)	Btu/kWh-HHV	Note 11	Note 11	12,550	Note 11	Note 11	N/A	7,450	7,600	8,100	8,250
Fixed O&M (Notes 1, 7)	2021$/kW-yr	63.9	37.2	43	41.9	45.5	12.04	40	41	40	41
Variable O&M (Notes 1, 7)	2021$/MWh	7.97	6.37	7.8	1.8	3.4	N/A	5.4	5.3	5.4	5.3
19% Aqueous Ammonia Consumption Rate	lb/MWh	3.9	5.8	2.6	0.8	3.9	N/A	1.8	1.9	1.8	1.8
Water Consumption Rate (Note 6)	gal/MWh	150	135	40	Negligible	49	N/A	340	40	320	30
NO_X Emission Rate	lb/MWh	0.7	0.509	0.17	2.17	0.23	N/A	0.08	0.08	0.08	0.08
CO_2 emission rate	lb/MWh	362	2187	960	1,391	2,491	N/A	860	870	850	860
Maintenance Outage Hours	hrs	164	358	150	229	164	0	100	100	100	100
Forced Outage Hours	hrs	415	510	220	638	415	0	140	140	140	140
Maintenance Outage Rate	%	2.34%	4.62%	N/A	2.87%	2.34%	N/A	N/A	N/A	N/A	N/A
Equivalent Forced Outage Rate	%	9.08%	11.33%	N/A	22.64%	9.08%	N/A	N/A	N/A	N/A	N/A

		11	13	14	15	16	17	18	19	20
Requested Characteristics for Natural Gas	**Description**	**Ben French 10MW Diesel to NG Convert**	**1x1 7HA.02 CCCT w/o DF**	**3x1 LM6000 PF+ CCCT w/o DF**	**2x1 LM6000 PF+ CCCT w/o DF**	**2x1 LM6000 PF+ CCCT w/o DF at CPGS**	**1x1 LM6000 PF+ CCCT with DF**	**1x0 LMS100 SCCT**	**1x0 LM6000 PF+ SCCT**	**1x0 7EA SCCT**
Gross Output	MW	7.7	456	172	114	115	76	93	43	77
Nominal Net Output	MW	7.5	444	167	111	112	73	91	42	75
Nominal Net Heat Rate	Btu/kWh-HHV	11,850	6,300	7,050	7,050	7,050	7,850	8,750	9,400	11,200
Greenfield/Brownfield	-	Brownfield	Greenfield	Greenfield	Greenfield	Greenfield	Greenfield	Greenfield	Greenfield	Greenfield
Capacity Factor (Note 7)	%/yr	10%	80%	80%	80%	80%	80%	30%	30%	30%
Turnkey EPC Cost (Note 1)	2021$/kW	350	791	1,380	1,455	1,442	1,318	1,082	1,249	1,249
Owner's Cost (Note 1)	2021$/kW	77	198	345	364	360	330	238	275	275
Total Investment Cost (Notes 1, 2)	2021$/kW	427	989	1,726	1,818	1,802	1,648	1,320	1,524	1,524
Annual Average MAX Load (Notes 3, 4, 5)	MW	7.5	444	167	111	112	73	91	42	75
Annual Average MID Load (Notes 3, 4, 5)	MW	3.8	351	129	86	87	54	68	31	57
Annual Average MIN Load (Notes 3, 4, 5)	MW	2.5	150	95	64	64	30	22	21	34
Annual Average MAX Load Heat Rate (Notes 3, 4, 5)	Btu/kWh-HHV	11,900	6,300	7,050	7,050	7,050	7,850	8,750	9,400	11,200
Annual Average MID Load Heat Rate (Notes 3, 4, 5)	Btu/kWh-HHV	13,100	6,500	7,400	7,400	7,400	7,250	9,350	10,250	12,450
Annual Average MIN Load Heat Rate (Notes 3, 4, 5)	Btu/kWh-HHV	15,450	7,850	8,150	8,150	8,150	8,700	14,300	12,550	15,300
Fixed O&M (Notes 1, 7)	2021$/kW-yr	Minimal change	10	28	37	37	50	18	43	43
Variable O&M (Notes 1, 7)	2021$/MWh	Minimal change	3.5	4.2	5.2	5.2	6.7	5.3	7.8	7.8
19% Aqueous Ammonia Consumption Rate	lb/MWh	N/A	1.6	1.8	1.8	1.8	1.9	2.0	2.2	0.8
Water Consumption Rate (Note 6)	gal/MWh	Negligible	270	320	320	320	480	180	40	20
NO_X Emission Rate	lb/MWh	8.85	0.07	0.08	0.08	0.08	0.09	0.16	0.17	0.21
CO_2 emission rate	lb/MWh	1,390	750	840	840	840	940	1,040	1,110	1,350
Maintenance Outage Hours	hrs	90	100	100	100	100	100	150	150	150
Forced Outage Hours	hrs	380	140	140	140	140	140	220	220	220
Maintenance Outage Rate	%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Equivalent Forced Outage Rate	%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

		21	22	23	24	25	26	31	32	33	35
Requested Characteristics for Natural Gas	**Description**	**200 MW Solar PV SAT**	**100 MW Solar PV SAT**	**50 MW Solar PV SAT**	**200 MW Wind**	**100 MW Wind**	**50 MW Wind**	**100 MW Biofuel Plant**	**40 MW Geo-thermal Plant**	**Small Scale Modular Reactor (Note 8)**	**NS2 Retirement (Note 10)**
Gross Output	MW	N/A	N/A	N/A	N/A	N/A	N/A	105	46	111	N/A
Nominal Net Output	MW	200	100	50	200	100	50	100	40	100	N/A
Nominal Net Heat Rate	Btu/kWh-HHV	N/A	N/A	N/A	N/A	N/A	N/A	13,500	N/A	10,500	N/A
Greenfield/Brownfield	-	Greenfield	Greenfield	Greenfield	Greenfield	Greenfield	Greenfield	Greenfield	Greenfield	Greenfield	N/A
Capacity Factor (Note 7)	%/yr	20%	20%	20%	42%	43%	45%	60%	80%	95%	N/A
Turnkey EPC Cost (Note 1)	2021$/kW	1,101	1,124	1,164	1,125	1,142	1,144	4,080	7,146	3,782	N/A
Owner's Cost (Note 1)	2021$/kW	220	225	233	225	228	229	816	1,429	756	N/A
Total Investment Cost (Notes 1, 2)	2021$/kW	1,321	1,349	1,397	1,351	1,371	1,373	4,896	8,576	4,538	1.30
Annual Average MAX Load (Notes 3, 4, 5)	MW	N/A	N/A	N/A	N/A	N/A	N/A	100	N/A	N/A	N/A
Annual Average MID Load (Notes 3, 4, 5)	MW	N/A	N/A	N/A	N/A	N/A	N/A	75	N/A	N/A	N/A
Annual Average MIN Load (Notes 3, 4, 5)	MW	N/A	N/A	N/A	N/A	N/A	N/A	40	N/A	N/A	N/A
Annual Average MAX Load Heat Rate (Notes 3, 4, 5)	Btu/kWh-HHV	N/A	N/A	N/A	N/A	N/A	N/A	13,500	N/A	10,500	N/A
Annual Average MID Load Heat Rate (Notes 3, 4, 5)	Btu/kWh-HHV	N/A	N/A	N/A	N/A	N/A	N/A	13,700	N/A	N/A	N/A
Annual Average MIN Load Heat Rate (Notes 3, 4, 5)	Btu/kWh-HHV	N/A	N/A	N/A	N/A	N/A	N/A	15,000	N/A	N/A	N/A
Fixed O&M (Notes 1, 7)	2021$/kW-yr	7	7	7	30	32	34	125	200	100	1.30
Variable O&M (Notes 1, 7)	2021$/MWh	N/A	N/A	N/A	N/A	N/A	N/A	4.8	N/A	3.0	N/A
19% Aqueous Ammonia Consumption Rate	lb/MWh	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Water Consumption Rate (Note 6)	gal/MWh	N/A	N/A	N/A	N/A	N/A	N/A	1,000	238	558	N/A
NO_X Emission Rate	lb/MWh	N/A	N/A	N/A	N/A	N/A	N/A	0.12	N/A	N/A	N/A
CO_2 emission rate	lb/MWh	N/A	N/A	N/A	N/A	N/A	N/A	3,190	N/A	N/A	N/A
Maintenance Outage Hours	hrs	N/A	N/A	N/A	N/A	N/A	N/A	640	640	380	0
Forced Outage Hours	hrs	N/A	N/A	N/A	N/A	N/A	N/A	560	450	60	0
Maintenance Outage Rate	%	0%	0%	0%	0.5%	0.5%	0.5%	N/A	N/A	N/A	N/A
Equivalent Forced Outage Rate	%	2%	2%	2%	4.5%	4.5%	4.5%	N/A	N/A	N/A	N/A

Notes to Table 3-16:

1. Estimates are indicative. All cost estimates expressed as 2021$/kW, 2021$/kW-yr, or 2021$/MWh are based on the Annual Average Capacity of an option.

2. Total Investment Cost equals the sum of the Turnkey EPC Cost and Owner's Cost.

3. All annual average values are on a new-and-clean, net output or net heat rate (HHV) basis.

4. For dispatchable resources MAX is at maximum load, MIN is at minimum emissions compliance load (varies from 25 percent to 70 percent load), and MID is at an intermediate load (generally 75 percent load). MIN load is considered with all units in operation. Plant load could be reduced further for plants with multiple units by completely shutting down one or more units.

5. Annual average conditions: NSC 4,410ft, 64.2F Dry Bulb, 47.8F Wet Bulb - CPGS 5,837ft, 60F Dry Bulb, 38F Wet Bulb - Generic Greenfield 6,000ft, 60F Dry Bulb, 38F Wet Bulb.

6. Water consumption rates are shown during average hot day conditions.

7. Dispatchable resource capacity factors used for O&M cost estimating purposes only. Wind and Solar Capacity Factors exclude the effects of unavailability.

8. Advanced SMRs are expected to be commercially available as early as 2030. They will also incur decommissioning prepayments of at least $40 million dollars.

9. Included emission rates are stack emissions rates which are considered after any additional duct burner emissions and after an SCR, as applicable to each option.

10. Options 6 and 35 do not have all characteristics because the units would be inactive. If Option 6 is taken out of cold reserve the characteristics would be the same as they were prior to alterations.

11. The Average MID and MIN Loads vary widely by facility as they are dictated by the state and local grid requirements.

Table 3-17 Black Hills Power and Cheyenne Light Fuel and Power Busbar Screening Option Characteristics Table – BESS Options

		Black Hills Energy and Cheyenne Battery Energy Storage System (BESS) Bus-Bar Screening				
Identifier		**Option 12**	**Option 27**	**Option 28**	**Option 29**	**Option 30**
Requested Characteristics for BESS, including description of adjacent configuration	**Description**	**10 _MW, 4 hr BESS as Diesel Replacement**	**Stand alone 4hr BESS 10_MW**	**Stand alone 4hr BESS 30_MW**	**Stand alone 4hr BESS 100_MW**	**Stand alone 4 hr BESS 200_MW**
BESS Battery Type	**-**	**Energy**	**Energy**	**Energy**	**Energy**	**Energy**
Gross Output	**MW**	**10**	**10**	**30**	**100**	**200**
Configuration Rated Power	**MW**	**10**	**10**	**30**	**100**	**200**
Configuraiton Rated Duration	**hour**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**
Configuration Rated Energy	**MWh**	**40**	**40**	**120**	**400**	**800**
Nominal Net Power Output	MW	10	10	30	100	200
Nominal *Nameplate* Rating (Note 1)	MWh (NP)	75	75	225	749	1,498
Nominal *Actual* Rating at end-of-life (Note 1)	MWh (A)	40	40	120	400	800
Greenfield/Brownfield	-	Brownfield	Greenfield	Greenfield	Greenfield	Greenfield
Use Case : a cumulative charge/discharge is one cycle	cycles/year	365	365	365	365	365
Turnkey EPC Unit Cost per Nameplate Energy	2021$/kWh(NP)	255	255	235	215	204
Owner's Unit Cost per Nameplate Energy	2021$/kWh(NP)	28	28	26	24	23
Total Equipment Unit Cost per Nameplate Energy	2021$/kWh(NP)	283	283	261	239	227
TOTAL EQUIPMENT Installed COST Real 2021USD	**2021 Real $**	**21,224,965**	**21,224,965**	**58,703,092**	**178,997,263**	**340,094,801**
Fixed O&M (Notes 1, 7)	2021$/kWh(A)-yr	7.5	7.5	7.5	7.5	7.5
Variable O&M (excluding charging electricity)	2021$/kWh(A)	0.0	0.0	0.0	0.0	0.0
BESS Facility Life	Years	20	20	20	20	20
Estimated COD	COD	2023	2023	2023	2023	2023
Maintenance Outage Hours	hrs	20	20	30	60	80
Forced Outage Hours	hrs	40	40	60	120	160

		Black Hills Energy and Cheyenne Battery Energy Storage System (BESS) Bus-Bar Screening				
Identifier		**Option 34 A**	**Option 34 B**	**Option 34 C**	**Option 34 D**	**Option 34 E**
Requested Characteristics for BESS, including description of adjacent configuration	**Description**	**Add 30 min BESS to LM6000 137_MW**	**Add 30 min BESS to LM6000 100_MW**	**Add 30 min BESS to LM6000* 100_MW**	**Add 30 min BESS to LM6000 56_MW**	**Add 30 min BESS to LM6000 40_MW**
BESS Battery Type	**-**	**Power**	**Power**	**Power**	**Power**	**Power**
Gross Output	**MW**	**137**	**100**	**100**	**56**	**40**
Configuration Rated Power	**MW**	**137**	**100**	**100**	**56**	**40**
Configuraiton Rated Duration	**hour**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**
Configuration Rated Energy	**MWh**	**68.5**	**50**	**50**	**28**	**20**
Nominal Net Power Output	MW	137	100	100	56	40
Nominal *Nameplate* Rating (Note 1)	MWh (NP)	128	94	94	52	37
Nominal *Actual* Rating at end-of-life (Note 1)	MWh (A)	69	50	50	28	20
Greenfield/Brownfield	-	Brownfield	Brownfield	Brownfield	Brownfield	Greenfield
Use Case : a cumulative charge/discharge is one cycle	cycles/year	365	365	365	365	365
Turnkey EPC Unit Cost per Nameplate Energy	2021$/kWh(NP)	290	297	297	310	317
Owner's Unit Cost per Nameplate Energy	2021$/kWh(NP)	32	33	33	34	35
Total Equipment Unit Cost per Nameplate Energy	2021$/kWh(NP)	322	330	330	344	353
TOTAL EQUIPMENT Installed COST Real 2021USD	**2021 Real $**	**41,293,898**	**30,851,957**	**30,851,957**	**18,034,536**	**13,206,584**
Fixed O&M (Notes 1, 7)	2021$/kWh(A)-yr	7.5	7.5	7.5	7.5	7.5
Variable O&M (excluding charging electricity)	2021$/kWh(A)	0.0	0.0	0.0	0.0	0.0
BESS Facility Life	Years	20	20	20	20	20
Estimated COD	COD	2023	2023	2023	2023	2023
Maintenance Outage Hours	hrs	20	20	20	20	20
Forced Outage Hours	hrs	40	40	40	40	40

Notes to Table 3-17:

1. Estimates are indicative. Nameplate is the MWh of all battery cells installed (NP).

   Actual is the MWh available given lithium-ion BESS characteristics for limits on depth-of-discharge and average state of charge. (A)

   Both values include the necessary additional initial capacity such that end-of-life capability meets specification. "

2. All cost estimates expressed as 2021$/kW, 2021$/kW-yr, or 2021$/MWh are based on the Annual Average Use Case for an option.

3. Total Investment Cost equals the sum of the Turnkey EPC Cost and Owner's Cost.

4. All annual average values are on a new-and-clean, net output.

5. Annual average conditions: NSC 4,410ft, 64.2F Dry Bulb, 47.8F Wet Bulb - CPGS 5,837ft, 60F Dry Bulb, 38F Wet Bulb - Generic Greenfield 6,000ft, 60F Dry Bulb, 38F Wet Bulb.

6. Dispatchable resource capacity used for O&M cost estimating purposes.

7. Options 34A through 34E are a one-to-one match with the LM6000 units used in the natural gas options. Option 34A is the BESS option for Option 14, Option 34B is the BESS option for Option 15, Option 34C is the BESS Option for Option 16, Option 34D is the BESS option for Option 17, and Option 34E is the BESS Option for Option 19. So, Option 34B is the 100MW LM6000 and Option 34C is the 100 MW LM6000 at CPGS.

8. Total Equipment Unit Cost was calculated using benchmark costing. Option 27 was used as the benchmark for Option 12 and Options 28-30 and Option 34D was used as the benchmark for Options 34A-E. For the off-baseline options, the unit cost was reduced for larger sizes and increased for smaller sizes (factored estimation). Black & Veatch used a factor of 5 percent for that increase/decrease in the following formula:

$$COSToption = COSTbaseline * \left[(1 - 0.05)^{\left\{ LOGbase2\left(\frac{NAMEPLATE_{MWHoption}}{NAMEPLATE_{MWHoption}}\right) \right\}} \right]$$

4.0 Busbar Model and Results

This section presents the busbar analysis for the list of candidate units evaluated. Busbar results are shown separately for BHP and CLFP due to different delivered natural gas prices and different performance estimates for renewable options that impact the busbar cost calculations.

The busbar analysis is performed for each technology listed in Section 3 across a realistic capacity factor range for each capacity type. A capacity factor measures unit energy output as a percentage of the maximum output the unit could produce if operating at full load all hours of the year. It is typical for base load units such as a combined cycle or a coal unit to operate at a high capacity factor, depending on market conditions and unit availability. A base load capacity factor range of 50 percent to 90 percent is likely to capture the operating range of most baseload units, but the range was extended to 40 percent to 90 percent (at 10 percentage point increments) in this study.

For peaking units, busbar costs were projected for capacity factors from 5 percent to 35 percent and by increments of 10 percentage points within this range. For renewable energy solar and wind facilities, busbar costs were calculated based on the historical data and projections provided by BHP to Black & Veatch for specific sites, as well as capacity factor deviations of 3 percentage points higher and lower than the initial capacity factor flowing from the information received from BHP.

4.1 THE BUSBAR MODEL

As stated previously, a busbar model develops an all-in, levelized busbar cost of an option over a period of time. The “all-in” refers to the presentation of both fixed and variable costs on a $/MWh or cent/kWh basis, and “levelization” refers to the development of a single $/MWh or cent/kWh cost from the year-by-year busbar costs that normally vary due to the impacts of inflation on operating costs. This section provides some additional information on the busbar model used in this study.

Figure 4-1 shows a sample busbar model for one of the conventional options evaluated in this study, Option 7. The figure shows the description of Option 7 at the top, followed by several rows listing plant and economic input assumptions. The inputs are then followed by several columns that indicate the yearly unit cost categories of capital cost, fixed O&M cost, variable O&M cost, and fuel cost. The total yearly costs are then listed and are also stated on a total cost and cent/kWh cost basis. The levelized value is shown at the bottom of the table.

The annual capital cost shown in Figure 4-1 is derived by applying the levelized fixed charge rate to the total capital cost. The fixed O&M value is based on the $/kW-year cost times the kW of capacity. Variable O&M costs are lined to the capacity factor and the $/MWh variable O&M rate. Fuel costs are linked to the unit capacity, the capacity factor, the unit net plant heat rate, and the fuel cost. The annual cost components are summed horizontally to derive the total cost and total busbar cost of the unit for any given year. The final columns of Figure 4-1 also include present worth costs that are used in the levelization process, described below.

Based on the inputs shown in Figure 4-1, it is seen that Option 7 has a levelized cost of 7.19 cents/kWh at a 90 percent capacity factor. This levelized value has the following meaning: if the value of 7.19 cents/kWh were input into the Figure 4-1 column marked “Busbar Cost (c/kWh)” (the second column from the right hand side), the present value sum of the costs for all years in the column would be equal to the present value sum of the actual year-by-year busbar costs in the column, which start at 6.07 cents/kWh and end at 10.07 cents/kWh. Stated differently, the levelized cost can be thought of as an average, present worth all-in cost at the selected capacity factor over the 25-year evaluation period.

Appendix A includes a busbar table for each option evaluated. In the appendix, the busbar table is shown for the highest capacity factor evaluated for each option (90 percent for base load options, etc.).

Figure 4-1 shows the levelized busbar cost for Option 7 at a 90 percent capacity factor. In this study, busbar costs for Option 7 and all baseload options were calculated for capacity factors from 40 percent to 90 percent, which allows the development of a busbar cost curve as shown in Figure 4-2 for Option 7. As seen in the figure, as the capacity factor is reduced, the levelized busbar cost increases because unit fixed costs are spread over fewer kWh of generation. Since the yearly projected capacity factor of any unit will not be known until the more detailed production costing and expansion planning modeling occurs later in the IRP process, the comparison of busbar curves among competing options of a similar type (baseload, peaking, etc.) provides useful information when making screening decisions.

Option 7: 102 MW NSC CT1 (LM6000 PD) Conversion to 2x1 Wet Cooled CC				
25-Year Busbar Cost Calculation				
Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 98,328	First Year Fixed O&M Cost ($/kW-yr)	40.0	1.5%
Other Owner Costs, except Esc & IDC	$ 24,582	First Year Variable O&M ($/MWh)	5.40	1.5%
Total Capital Cost (with Esc & IDC)	$ 122,910	Fuel Rat ($/MMBTU)	4.08	
Total Net Output, Avg Ambient Cond. (kW)	102,000	Construction Period (months)		
Capacity Factor	90.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	7,200	Levelized Fixed Charge Rate (25 yr)	13.7%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	16,777	4,080	4,343	4.08	23,623	0	0	48,823	45,307	6.07	5.63
2022	16,777	4,141	4,408	3.96	22,899	0	0	48,226	41,530	6.00	5.16
2023	16,777	4,203	4,474	4.33	25,061	0	0	50,515	40,369	6.28	5.02
2024	16,777	4,266	4,541	4.69	27,160	0	0	52,744	39,115	6.56	4.86
2025	16,777	4,330	4,609	4.96	28,709	0	0	54,425	37,455	6.77	4.66
2026	16,777	4,395	4,678	5.05	29,254	0	0	55,105	35,192	6.85	4.38
2027	16,777	4,461	4,748	5.06	29,297	0	0	55,284	32,764	6.87	4.07
2028	16,777	4,528	4,820	5.19	30,060	0	0	56,185	30,900	6.99	3.84
2029	16,777	4,596	4,892	5.25	30,373	0	0	56,639	28,906	7.04	3.59
2030	16,777	4,665	4,965	5.29	30,653	0	0	57,061	27,025	7.10	3.36
2031	16,777	4,735	5,040	5.47	31,662	0	0	58,214	25,585	7.24	3.18
2032	16,777	4,806	5,115	5.57	32,274	0	0	58,973	24,053	7.33	2.99
2033	16,777	4,878	5,192	5.67	32,810	0	0	59,657	22,580	7.42	2.81
2034	16,777	4,951	5,270	5.83	33,761	0	0	60,759	21,340	7.56	2.65
2035	16,777	5,026	5,349	6.14	35,555	0	0	62,707	20,439	7.80	2.54
2036	16,777	5,101	5,429	6.43	37,210	0	0	64,518	19,515	8.02	2.43
2037	16,777	5,177	5,511	6.74	39,044	0	0	66,509	18,668	8.27	2.32
2038	16,777	5,255	5,593	7.05	40,839	0	0	68,464	17,833	8.51	2.22
2039	16,777	5,334	5,677	7.27	42,108	0	0	69,896	16,895	8.69	2.10
2040	16,777	5,414	5,762	7.56	43,797	0	0	71,750	16,094	8.92	2.00
2041	16,777	5,495	5,849	7.82	45,297	0	0	73,418	15,283	9.13	1.90
2042	16,777	5,578	5,936	7.97	46,156	0	0	74,447	14,381	9.26	1.79
2043	16,777	5,661	6,026	8.18	47,367	0	0	75,831	13,593	9.43	1.69
2044	16,777	5,746	6,116	8.58	49,702	0	0	78,342	13,032	9.74	1.62
2045	16,777	5,832	6,208	9.00	52,125	0	0	80,942	12,495	10.07	1.55
							Net Levelized Busbar Cost (c/kWh)				**7.19**
							Net Levelized Cost ($000s)				**57,845**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure 4-1 Busbar Cost Model for Option 7 at a 90 Percent Capacity Factor

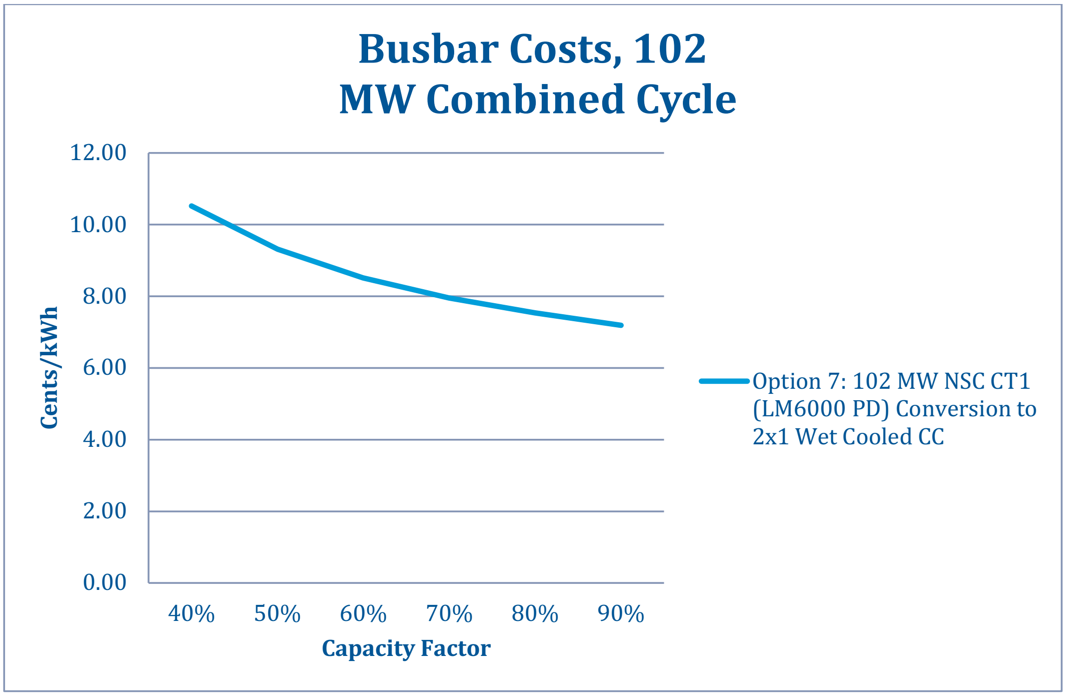

Figure 4-2 Busbar Curve for Option 7 at Selected Capacity Factors

4.2 BUSBAR MODEL RESULTS FOR THE TECHNOLOGIES EVALUATED

Not all of the technology options for which cost and performance estimates were developed in this study are suitable for a busbar model. This includes the option of placing the NS2 coal unit into cold reserves (Option 6) and the cost to retire NS2 (Option 35). Table 4-1 indicates whether a busbar analysis was performed for each option or whether the analysis consists only of the development of costs for that option.

The busbar results for the base load, peaking, renewable energy, and storage options are summarized in this section, beginning with the options for which a busbar analysis was performed. Results are organized according to technology type (base load, peaking, renewable energy, BESS) and location in Table 4-2 through Table 4-15. The tables are accompanied by figures plotting the busbar results. A cost summary of options for which a busbar analysis was not performed follows the busbar results, and is presented in Sections 4.3 and 4.4.

Table 4-1 Option Analysis Type Summary

OPTION NUMBER AND DESCRIPTION	BUSBAR PERFORMED (Y/N)	OTHER TYPE OF ANALYSIS
Option 1: A 100 MW carbon capture addition to existing 100 MW units in Gillette (NS2).	Yes	
Option 2: A new supercritical coal plant with carbon capture.	Yes	
Option 3: A conversion of LM6000 CT to burn 30 percent - 50 percent hydrogen blend.	Yes	
Option 4: An 80-100 MW coal to gas conversion unit.	Yes	
Option 5: An 80-100 MW coal plant life extension.	Yes	
Option 6: An 80-100 MW cold reserve unit.	No	Cold Reserve Cost Estimate
Option 7: Convert CT1 (LM6000 PD) to 2x1 wet cooled combined cycle resource.	Yes	
Option 8: Convert CT1 (LM6000 PD) to 2x1 dry cooled combined cycle resource.	Yes	
Option 9: Convert CT2 (LM6000 PF) to 2x1 wet cooled combined cycle resource.	Yes	
Option 10: Convert CT2 (LM6000 PF) to 2x1 dry cooled combined cycle resource.	Yes	
Option 11: Convert 10 MW Ben French diesel unit to fire natural gas.	Yes	
Option 12: A 10 MW battery – 4-hour lithium ion battery storage to replace diesels.	Yes	
Option 13: A 1x1 7HA.02 combined cycle plant without duct-firing.	Yes	
Option 14: A 3x1 LM6000 PF+ combined cycle plant without duct-firing.	Yes	

OPTION NUMBER AND DESCRIPTION	BUSBAR PERFORMED (Y/N)	OTHER TYPE OF ANALYSIS
Option 15: A 2x1 LM6000 PF+ combined cycle plant without duct-firing.	Yes	
Option 16: A 2x1 LM6000 PF+ combined cycle plant without duct-firing at CPGS.	Yes	
Option 17: A 1x1 LM6000 PF+ combined cycle plant with duct-firing.	Yes	
Option 18: A 1x0 LMS100 simple cycle combustion turbine peaking unit.	Yes	
Option 19: A 1x0 LM6000 PF+ simple cycle combustion turbine peaking unit.	Yes	
Option 20: A 1x0 7EA simple cycle combustion turbine peaking unit.	Yes	
Option 21: A 200 MW solar photovoltaic single axis tracking resource.	Yes	
Option 22: A 100 MW solar photovoltaic single axis tracking resource.	Yes	
Option 23: A 50 MW solar photovoltaic single axis tracking resource.	Yes	
Option 24: A 200 MW wind resource.	Yes	
Option 25: A 100 MW wind resource.	Yes	
Option 26: A 50 MW wind resource.	Yes	
Option 27: A 10 MW 4-hour lithium ion battery storage unit.	Yes	
Option 28: A 30 MW 4-hour lithium ion battery storage unit.	Yes	
Option 29: A 100 MW 4-hour lithium ion battery storage unit.	Yes	
Option 30: A 200 MW 4-hour lithium ion battery storage unit.	Yes	
Option 31: A 100 MW biofuels plant.	Yes	
Option 32: A 40 MW geothermal plant.	Yes	
Option 33: A 120 MW small scale modular reactor assumed to be available no sooner than 2030.	Yes	
Option 34A-E: Cost to add 30-minute battery to each LM6000.	Yes	
Option 35: NS2 Retirement.	No	Retirement Cost Estimate

4.2.1 Base Load Options

The busbar results for the conventional natural gas base load options are shown in Table 4-2 for the candidate units for the BHP service area in South Dakota (for purposes of natural gas pricing a location in Rapid City is assumed), and in Table 4-3 for the candidate units for the CLFP service area in Wyoming (assumed to be at the Neil Simpson Complex (NSC) in Gillette, or at the Cheyenne Prairie Generating Station (CPGS), Wyoming). In these tables, options that can be installed either in South Dakota or Wyoming are identified with "SD" or "W", respectively, following the option number, such as Option 13SD or Option 13W. Figure 4-3 and Figure 4-4 present the resulting busbar curves that correspond to the conventional BHP or CLHP base load options tables.

Table 4-2 Busbar Costs for Natural Gas Base Load Options for the BHP Service Area in South Dakota

UNIT	CAPACITY FACTOR					
	40%	50%	60%	70%	80%	90%
Option 13SD: 444 MW - 1x1 7HA.02 CC w/o DF	8.22	7.39	6.83	6.43	6.14	5.90
Option 14SD: 167 MW - 3x1 LM6000 PF+ CC w/o DF	12.19	10.67	9.65	8.92	8.38	7.95
Option 15SD: 111 MW - 2x1 LM6000 PF+ CC w/o DF	12.96	11.30	10.20	9.41	8.82	8.36
Option 17SD: 73 MW - 1x1 LM6000 PF+ CC with DF	13.35	11.74	10.67	9.90	9.33	8.88

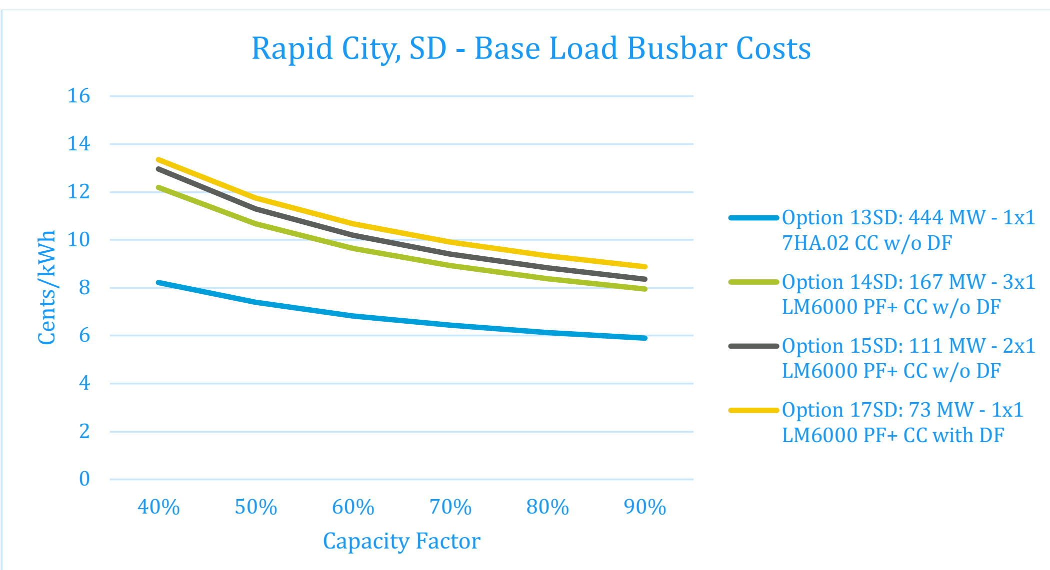

Figure 4-3 Busbar Curves for Natural Gas BHP Base Load Options in South Dakota

Table 4-3 Busbar Costs for Natural Gas Base Load Options for the CLFP Service Area in Gillette and Cheyenne, Wyoming

UNIT	CAPACITY FACTOR					
	40%	50%	60%	70%	80%	90%
Option 7: 102 MW – NSC CT1 (LM6000 PD) Convert to 2x1 Wet CC	10.52	9.32	8.52	7.95	7.53	7.19
Option 8: 101 MW – NSC CT1 (LM6000 PD) Convert to 2x1 Dry CC	10.84	9.59	8.76	8.17	7.72	7.37
Option 9: 97 MW – CPGS CT2 (LM6000 PF) Convert to 2x1 Wet CC	10.03	8.79	7.96	7.36	6.92	6.57
Option 10: 96 MW – CPGS CT2 (LM6000 PF) Convert to 2x1 Dry CC	10.33	9.03	8.17	7.55	7.08	6.72
Option 13W: 444 MW - 1x1 7HA.02 CC w/o DF at CPGS	7.38	6.55	5.99	5.59	5.29	5.06
Option 14W: 167 MW - 3x1 LM6000 PF+ CC w/o DF at CPGS	11.25	9.72	8.71	7.98	7.43	7.01
Option 15W: 111 MW - 2x1 LM6000 PF+ CC w/o DF at CPGS	12.02	10.36	9.25	8.47	7.87	7.41
Option 16: 112 MW - 2x1 LM6000 PF+ CC w/o DF at CPGS	11.95	10.31	9.21	8.43	7.84	7.39
Option 17W: 73 MW - 1x1 LM6000 PF+ CC with DF at CPGS	12.30	10.69	9.62	8.86	8.28	7.83

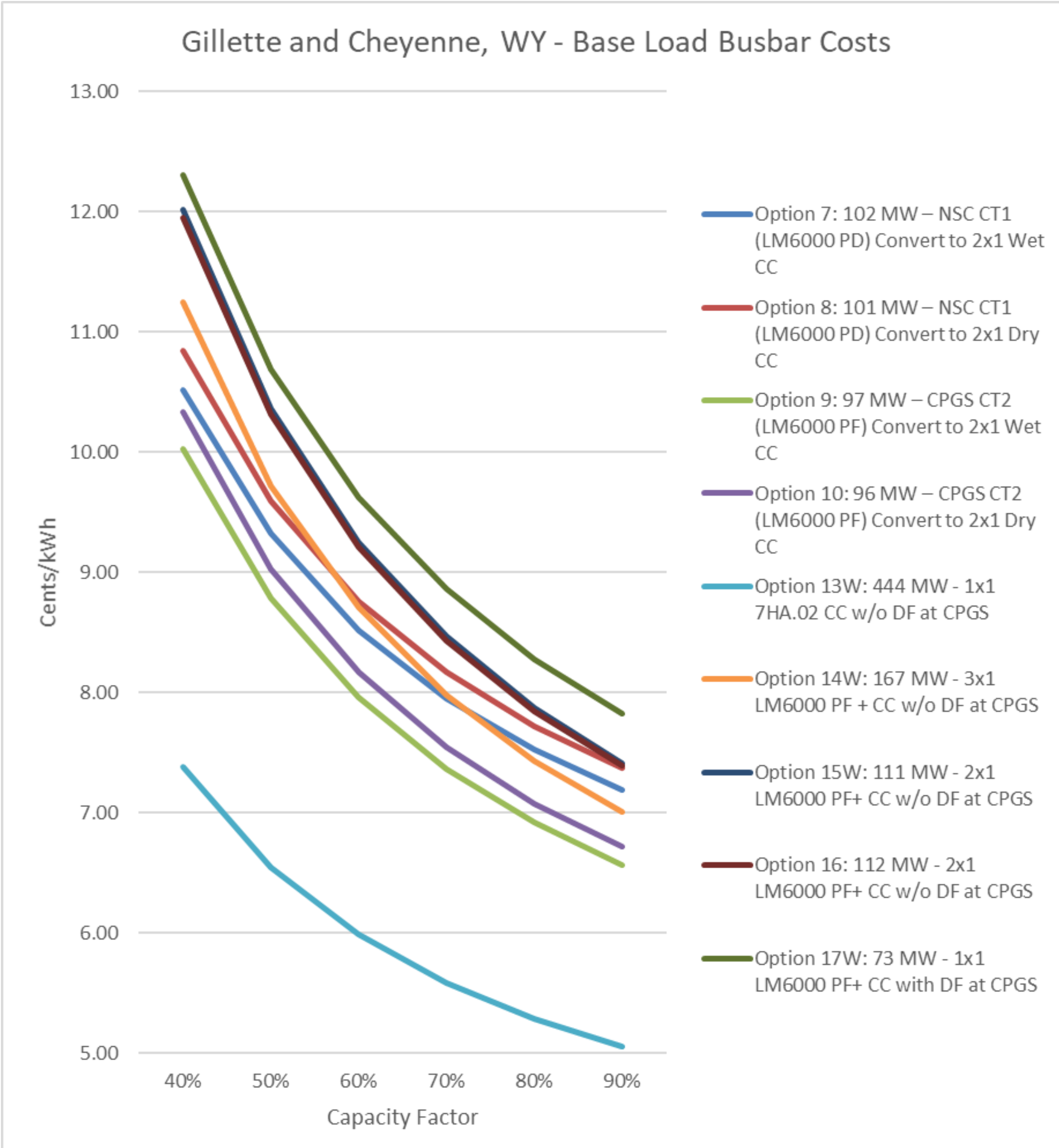

Figure 4-4 Busbar Curves for Natural Gas Base Load Options in Gillette and Cheyenne, Wyoming

Table 4-4 shows the busbar results for the other base load options including the coal plant options and the small modular reactor. These three units are base load options, as with those in Figure 4-4, but the busbar results are shown separately due to the difference in the cent/kWh scale used in Figure 4-5.

Table 4-4 Busbar Costs for Coal Plants and SMR Base Load Options

UNIT	CAPACITY FACTOR 40%	50%	60%	70%	80%	90%
Option 1: 100 MW (90%) Carbon Capture System Installed at Existing 100 MW Unit in Gillette	22.27	18.25	15.57	13.66	12.22	11.11
Option 2: New 500 MW Supercritical Coal Plant with CO_2 Capture	42.65	34.50	29.07	25.20	22.29	20.02
Option 4: 80-100 MW Coal to Gas Conversion Unit	8.98	8.61	8.36	8.19	8.05	7.95
Option 5: 80-100 MW Coal Plant Life Extension	12.16	10.09	8.71	7.73	6.99	6.41
Option 33: 100 MW SMR	22.90	18.52	15.61	13.52	11.96	10.75

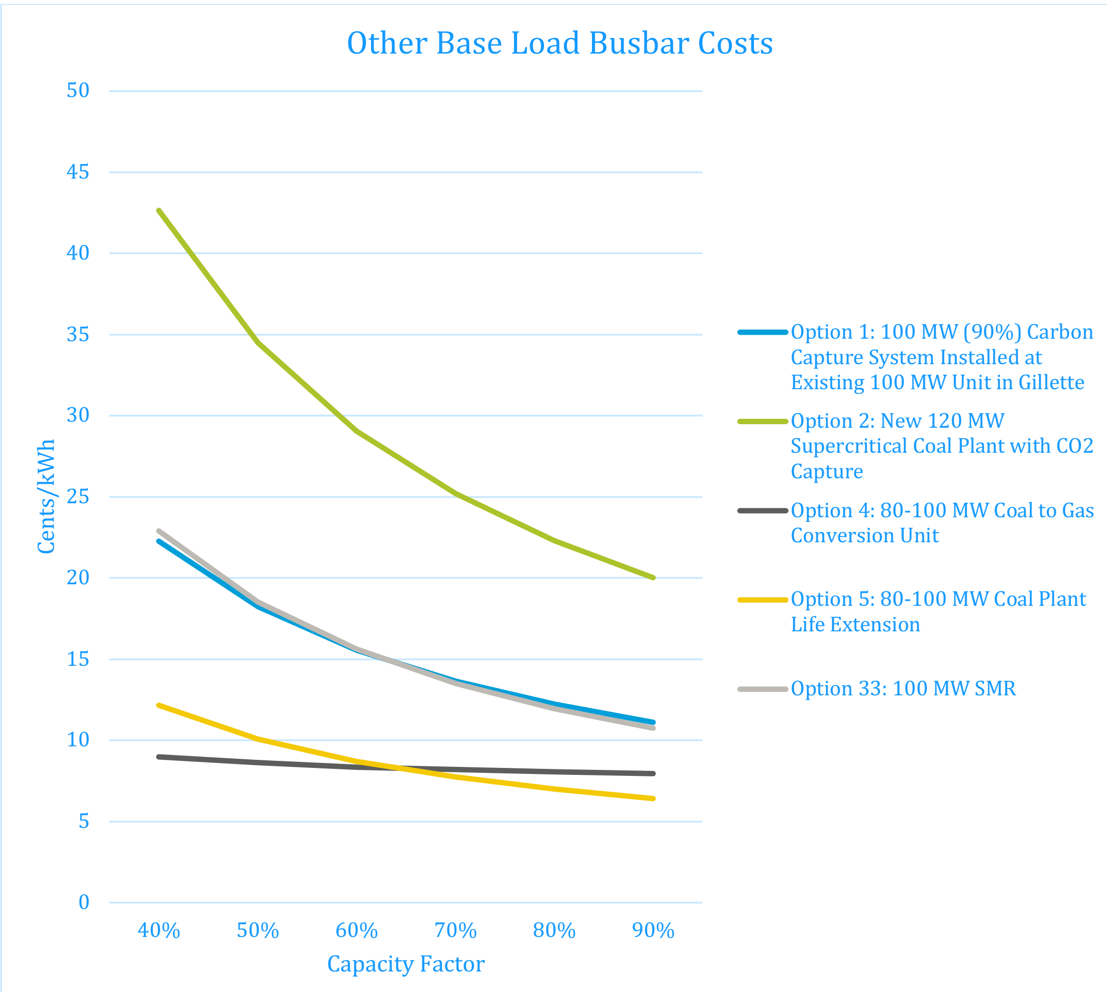

Figure 4-5 Busbar Curves for Coal Plants and SMR Base Load Options

The final two base load options in the analysis are for the two renewable base load options shown in Table 4-5 and Figure 4-6.

Table 4-5 Busbar Costs for Renewable Base Load Options

UNIT	CAPACITY FACTOR					
	40%	50%	60%	70%	80%	90%
Option 31: 100 MW Biofuel Plant	27.32	22.94	20.02	17.93	16.37	15.15
Option 32: 40MW Geothermal	34.65	27.72	23.10	19.80	17.32	15.40

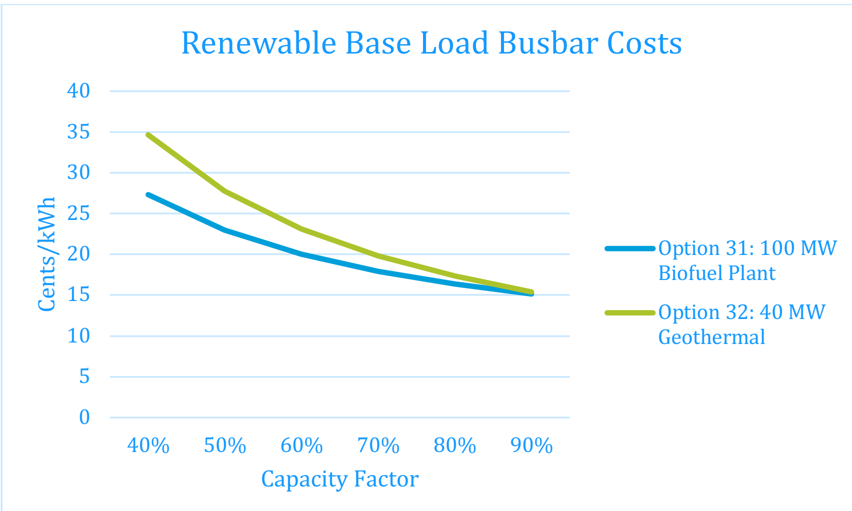

Figure 4-6 Busbar Curves for Renewable Base Load Options

4.2.2 Peaking Options

The busbar results for the natural gas peaking options are shown in Table 4-6 for the candidate BHP units and Table 4-7 indicates the busbar results for candidate units in Wyoming. Cheyenne was assumed for the candidate units in Wyoming because of the lower gas prices. Figure 4-4 and Figure 4-7 plot the busbar result curves for each peaking option location.

Table 4-6 Busbar Costs for Peaking Options in Rapid City, South Dakota

UNIT	CAPACITY FACTOR			
	5%	15%	25%	35%
Option 11: Convert 10 MW Diesel to Natural Gas	19.78	11.19	9.47	8.73
Option 18SD: 91 MW - 1x0 LMS100 CT	50.18	20.51	14.57	12.03
Option 19SD: 42 MW - 1x0 LM6000 PF+ CT	63.49	25.38	17.76	14.50
Option 20SD: 75 MW - 1x0 7EA CT	64.53	26.43	18.81	15.54

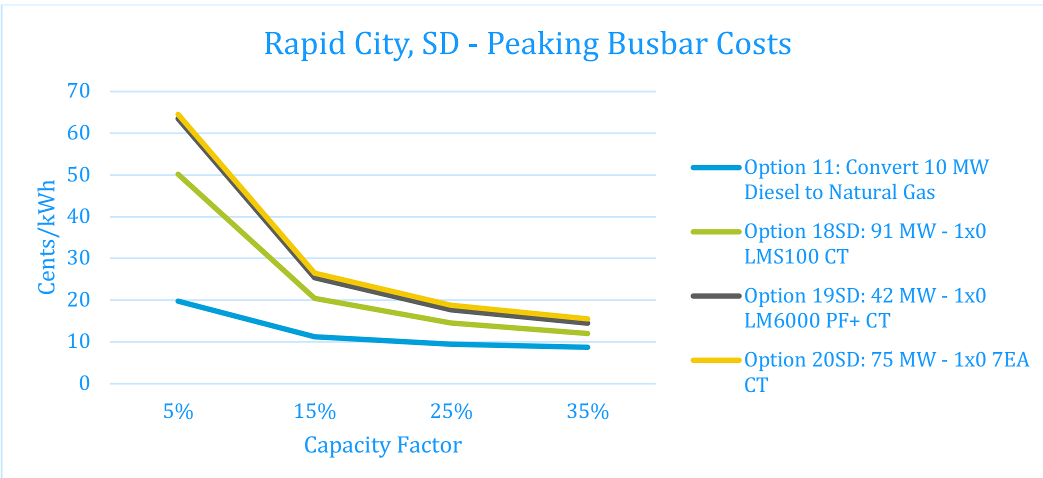

Figure 4-7 Busbar Curves for Peaking Options in Rapid City, South Dakota

Table 4-7 Busbar Costs for Peaking Options in Cheyenne, Wyoming

UNIT	CAPACITY FACTOR			
	5%	15%	25%	35%
Option 3: Conversion of LM6000 CT to Burn 35% Hydrogen Blend	27.17	17.47	15.53	14.70
Option 18W: 91 MW - 1x0 LMS100 CT	49.01	19.34	13.4	10.86
Option 19W: 42 MW - 1x0 LM6000 PF+ CT	62.23	24.13	16.51	13.24
Option 20W: 75 MW - 1x0 7EA CT	63.04	24.93	17.31	14.04

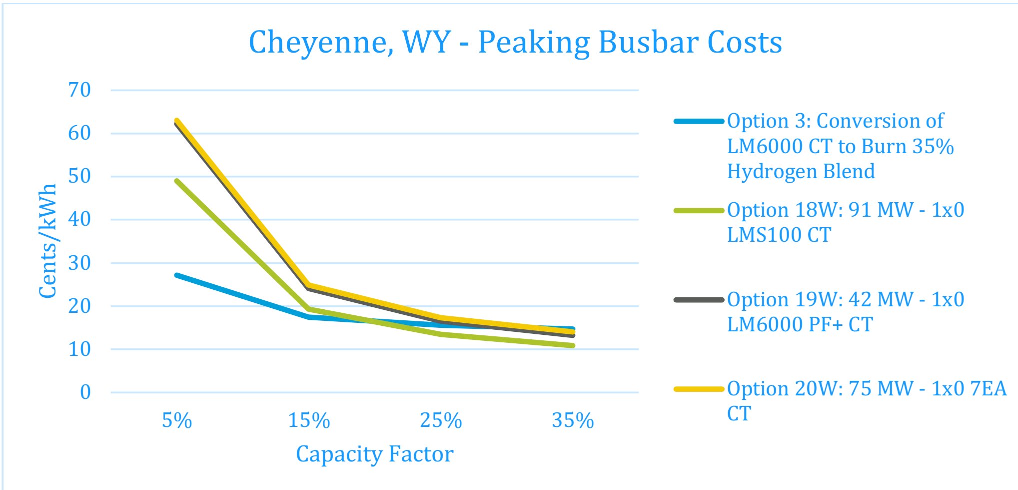

Figure 4-8 Busbar Costs for Peaking Options in Cheyenne, Wyoming

4.2.3 Solar Options

Solar busbar costs for specific locations were developed based on expected capacity factor information provided to Black & Veatch by BHP. Table 4-8 indicates busbar results for solar facilities of different sizes located in Gillette, Wyoming. Table 4-9 indicates busbar results for solar facilities of different sizes located in Hot Springs, South Dakota, and Table 4-10 shows busbar results for solar facilities of different sizes located in Cheyenne, Wyoming. Figure 4-9, Figure 4-10, and Figure 4-11 show the corresponding busbar curves for each of the solar options.

For each location, busbar costs were developed using the projected capacity factor estimate provided by BHP. Black & Veatch then added a three percentage point higher and a three percentage point lower capacity factor value around the BHP figure to allow the creation of a busbar curve. The options in Gillette were analyzed at a range of capacity factors from 15.7 to 21.7 percent, Hot Springs at a range from 18.6 to 24.6 percent, and Cheyenne at a range from 17.1 to 23.1 percent.

Table 4-8 Busbar Costs for Solar Options in Gillette, Wyoming

	CAPACITY FACTOR		
UNIT	15.7%	18.7%	21.7%
Option 21GW: 200 MW Solar PV SAT	11.63	9.76	8.41
Option 22GW: 100 MW Solar PV SAT	11.86	9.96	8.58
Option 23GW: 50 MW Solar PV SAT	12.26	10.30	8.87

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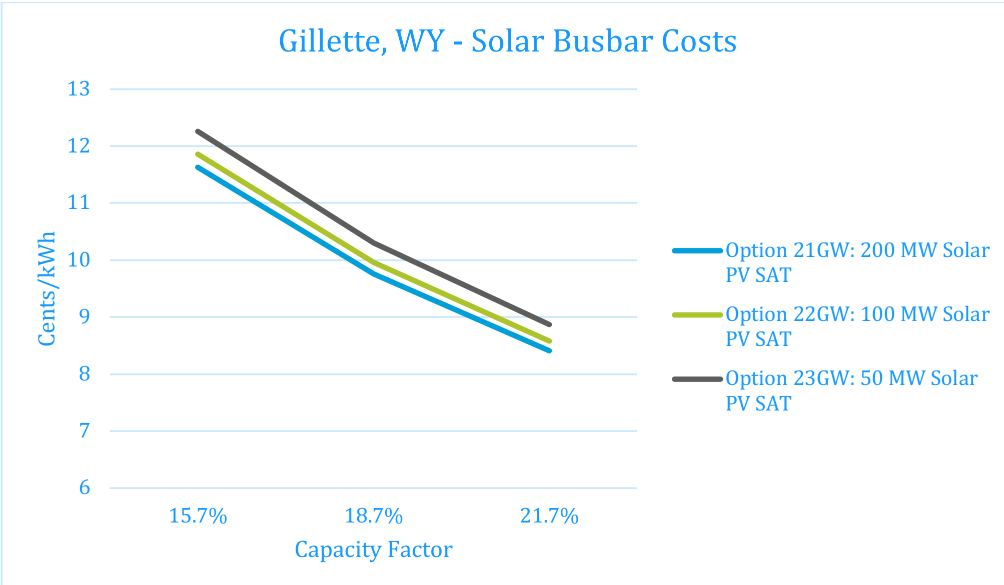

Figure 4-9 Busbar Curves for Solar Options in Gillette, Wyoming

Table 4-9 Busbar Costs for Solar Options in Hot Springs, South Dakota

UNIT	CAPACITY FACTOR		
	18.6%	21.6%	24.6%
Option 21SD: 200 MW Solar PV SAT	9.81	8.45	7.42
Option 22SD: 100 MW Solar PV SAT	10.01	8.62	7.57
Option 23SD: 50 MW Solar PV SAT	10.35	8.91	7.83

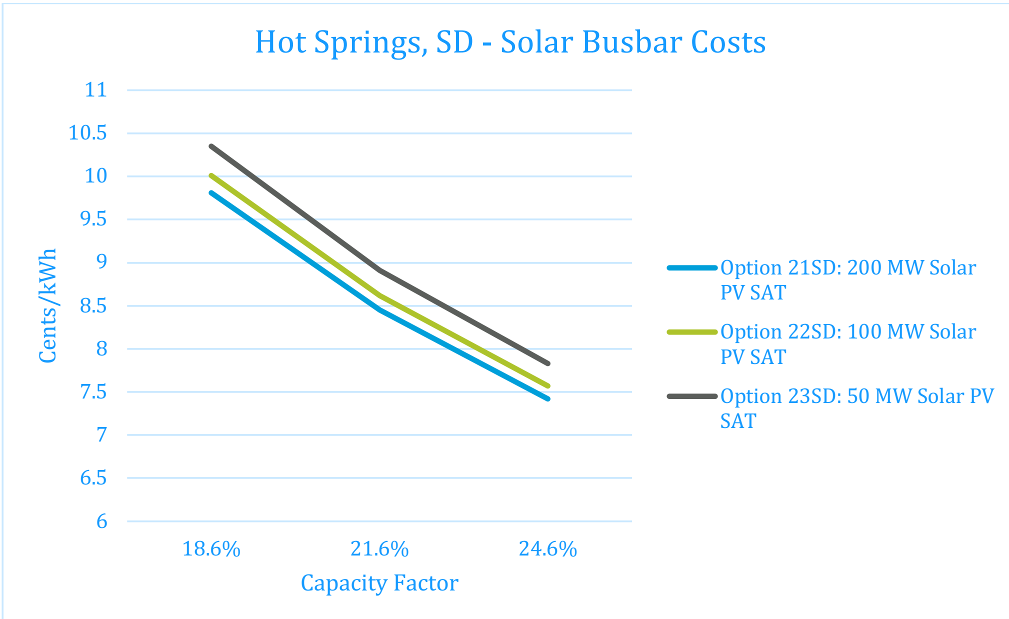

Figure 4-10 **Busbar Curves for Solar Options in Hot Springs, South Dakota**

Table 4-10 **Busbar Costs for Solar Options in Cheyenne, Wyoming**

UNIT	CAPACITY FACTOR 17.1%	20.1%	23.1%
Option 21CW: 200 MW Solar PV SAT	10.68	9.08	7.90
Option 22CW: 100 MW Solar PV SAT	10.89	9.27	8.06
Option 23CW: 50 MW Solar PV SAT	11.26	9.58	8.33

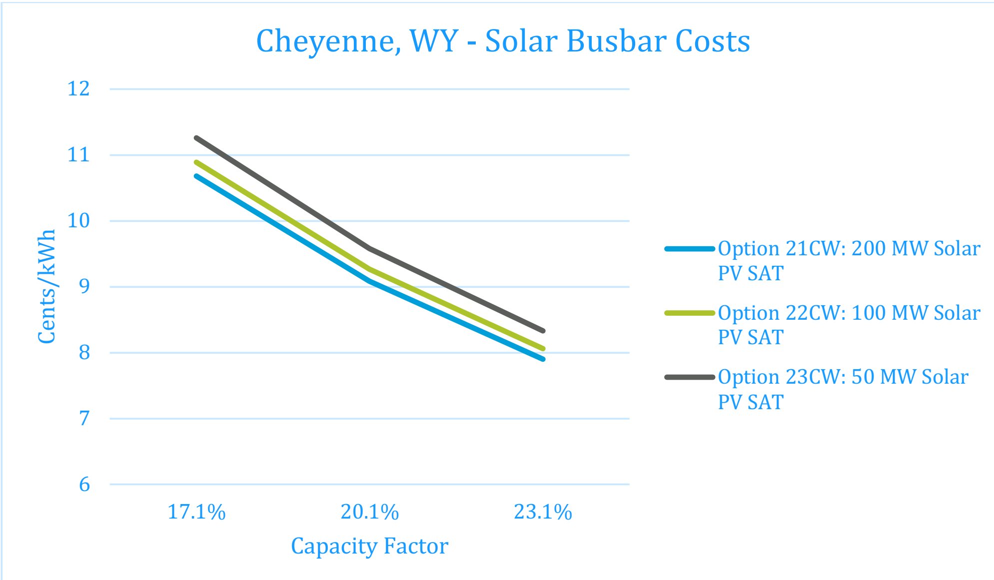

Figure 4-11 Busbar Curves for Solar Options in Cheyenne, Wyoming

4.2.4 Wind Options

Busbar results were generated for three locations (Cheyenne, Gillette, and Douglas, Wyoming) based upon projected capacity factor information provided by BHP for specific sites. Three percentage point high and low variations in capacity factors were combined with the estimated capacity factors provided by BHP to allow for the development of busbar cost curves at each location. The options in Cheyenne were analyzed at a range of capacity factors from 42.06 to 48.06 percent, Gillette at a range from 36.66 to 42.66 percent, and Douglas at a range from 39.42 to 45.42 percent.

The busbar results for the wind options are shown in Table 4-11 for the units in Cheyenne, Wyoming, in Table 4-12 for the units in Gillette, Wyoming, and in Table 4-14 for the units in Douglas, Wyoming. Figure 4-12, Figure 4-13, and Figure 4-14 below show the busbar result curves for each of the wind options.

Table 4-11 Busbar Costs for Wind Options in Cheyenne, Wyoming

UNIT	CAPACITY FACTOR		
	42.06%	45.06%	48.06%
Option 24CW: 200 MW Wind	5.14	4.80	4.50
Option 25CW: 100 MW Wind	5.27	4.92	4.61
Option 26CW: 50 MW Wind	5.34	4.98	4.67

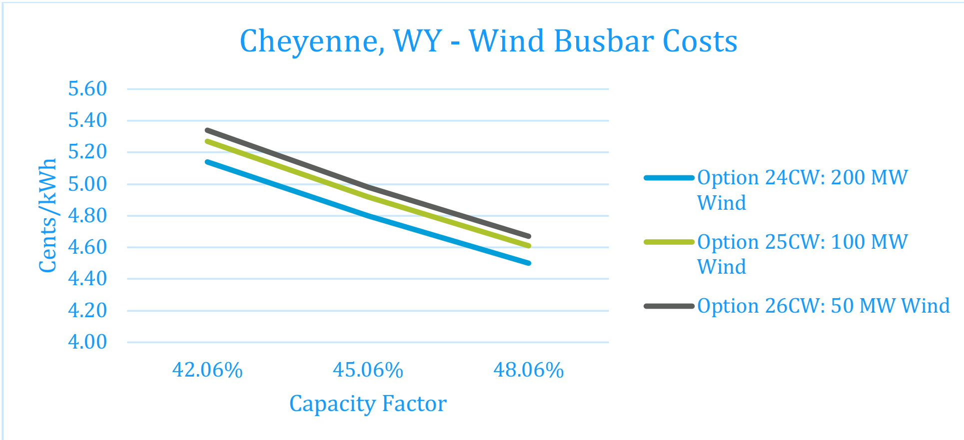

Figure 4-12 Busbar Curves for Wind Options in Cheyenne, Wyoming

Table 4-12 Busbar Costs for Wind Options in Gillette, Wyoming

UNIT	CAPACITY FACTOR		
	36.66%	39.66%	42.66%
Option 24GW: 200 MW Wind	5.90	5.46	5.07
Option 25GW: 100 MW Wind	6.04	5.59	5.19
Option 26GW: 50 MW Wind	6.12	5.66	5.26

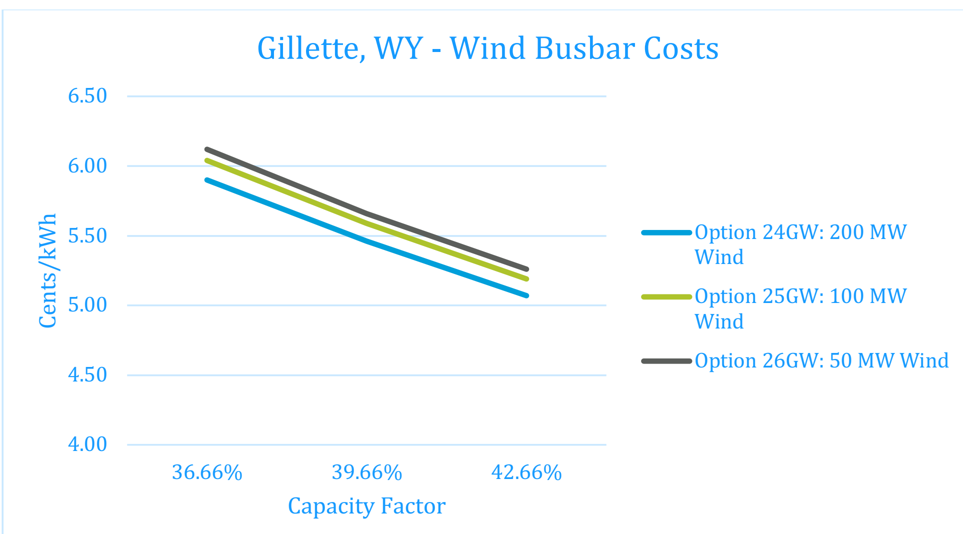

Figure 4-13 Busbar Curves for Wind Options in Gillette, Wyoming

Table 4-13 Busbar Costs for Wind Options in Douglas, Wyoming

UNIT	CAPACITY FACTOR		
	39.42%	42.42%	45.42%
Option 24DW: 200 MW Wind	5.49	5.10	4.76
Option 25DW: 100 MW Wind	5.62	5.22	4.88
Option 26DW: 50 MW Wind	5.69	5.29	4.94

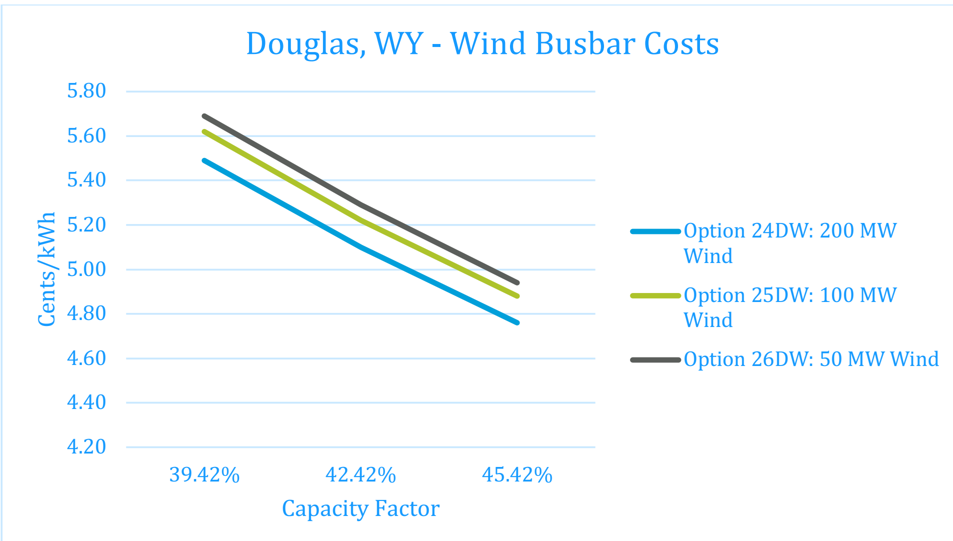

Figure 4-14 Busbar Curves for Wind Options in Douglas, Wyoming

4.2.5 BESS Options

The BESS option costs were analyzed and expressed based on an assumed average number of charging and discharging cycles per day (instead of capacity factors). The BESS options were modeled with a base case assumption that the BESS would be cycled once per day, on average, with sensitivities performed assuming one cycle occurring every other day (0.5 cycles per day), and twice a day. The greenfield BESS options were modeled in Wyoming and South Dakota because of the difference in assumed charging costs that comprise the variable O&M cost category for the BESS options. The busbar results for the battery storage options are shown in Table 4-14. The busbar result curve is shown in Figure 4-15.

Table 4-14 Busbar Costs for BESS Options in Wyoming

UNIT	CYCLES PER DAY		
	0.5	1	2
Option 12: 10 MW 4-hr BESS as Diesel Replacement	47.60	25.07	13.81
Option 27W: Stand Alone 4-hr BESS - 10 MW	47.60	25.07	13.81
Option 28W: Stand Alone 4-hr BESS - 30 MW	44.44	23.49	13.02
Option 29W: Stand Alone 4-hr BESS - 100 MW	41.26	21.90	12.22
Option 30W: Stand Alone 4-hr BESS - 200 MW	39.55	21.05	11.79
Option 34A: Add 30 min BESS to LM6000 - 137 MW	53.11	27.82	15.18
Option 34B: Add 30 min BESS to LM6000 - 100 MW	54.19	28.37	15.45
Option 34C: Add 30 min BESS to LM6000* - 100 MW	54.19	28.37	15.45
Option 34D: Add 30 min BESS to LM6000 - 56 MW	56.25	29.40	15.97
Option 34E-W: Add 30 min BESS to LM6000 - 40 MW	57.49	30.02	16.28
Note* Option 34B is the 100MW LM6000 and Option 34C is the 100 MW LM6000 PF+.			

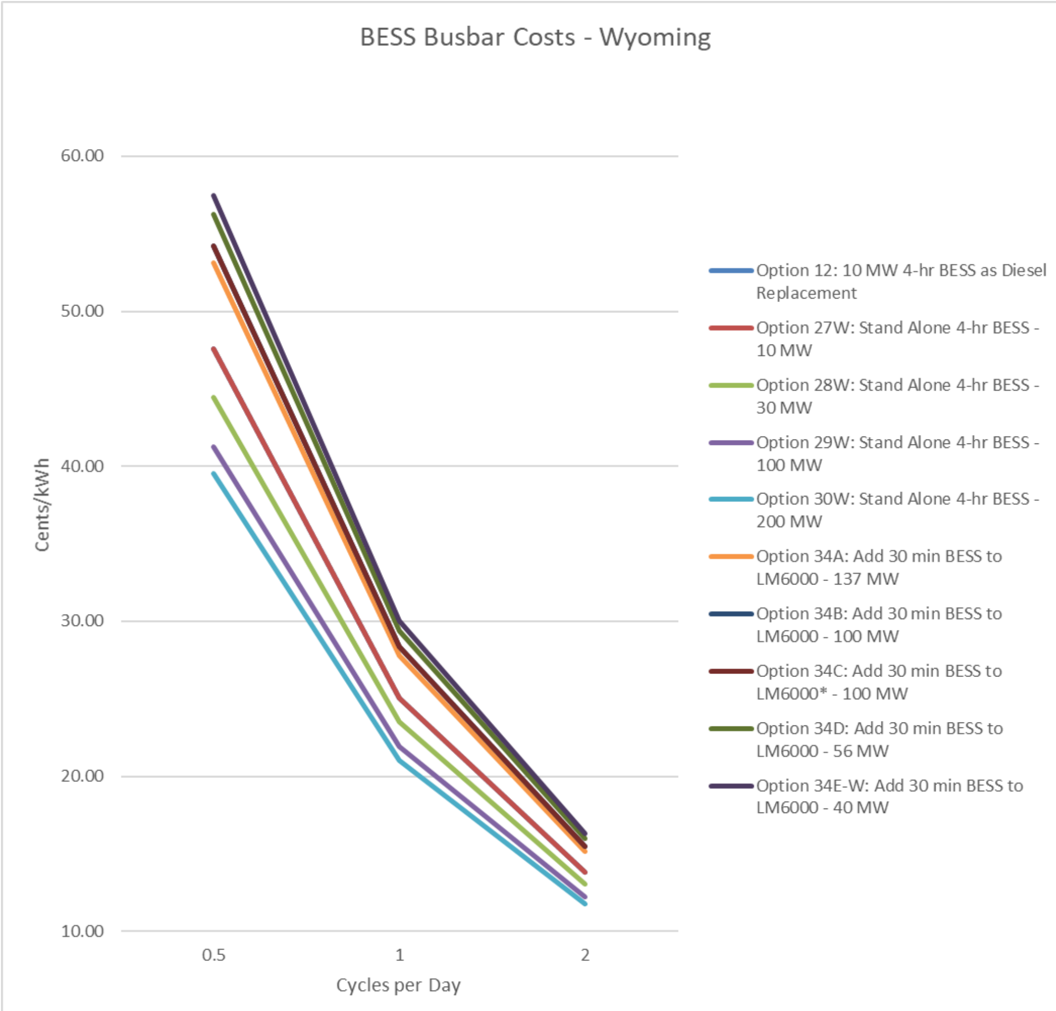

Figure 4-15 Busbar Costs for BESS Options in Wyoming*

Note* In Figure 4-15 Option 12 has the same exact costs as Option 27W, and Option 34B has the same exact costs as Option 34C so not all curves are visible.

Table 4-15 Busbar Costs for BESS Options in South Dakota

UNIT	CYCLES PER DAY		
	0.5	1	2
Option 27SD: Stand Alone 4-hr BESS - 10 MW	48.46	25.93	14.66
Option 28SD: Stand Alone 4-hr BESS - 30 MW	45.30	24.35	13.87
Option 29SD: Stand Alone 4-hr BESS - 100 MW	42.12	22.76	13.08
Option 30SD: Stand Alone 4-hr BESS - 200 MW	40.41	21.90	12.65
Option 34E-SD: Add 30 min BESS to LM6000 - 40 MW	58.35	30.87	17.14

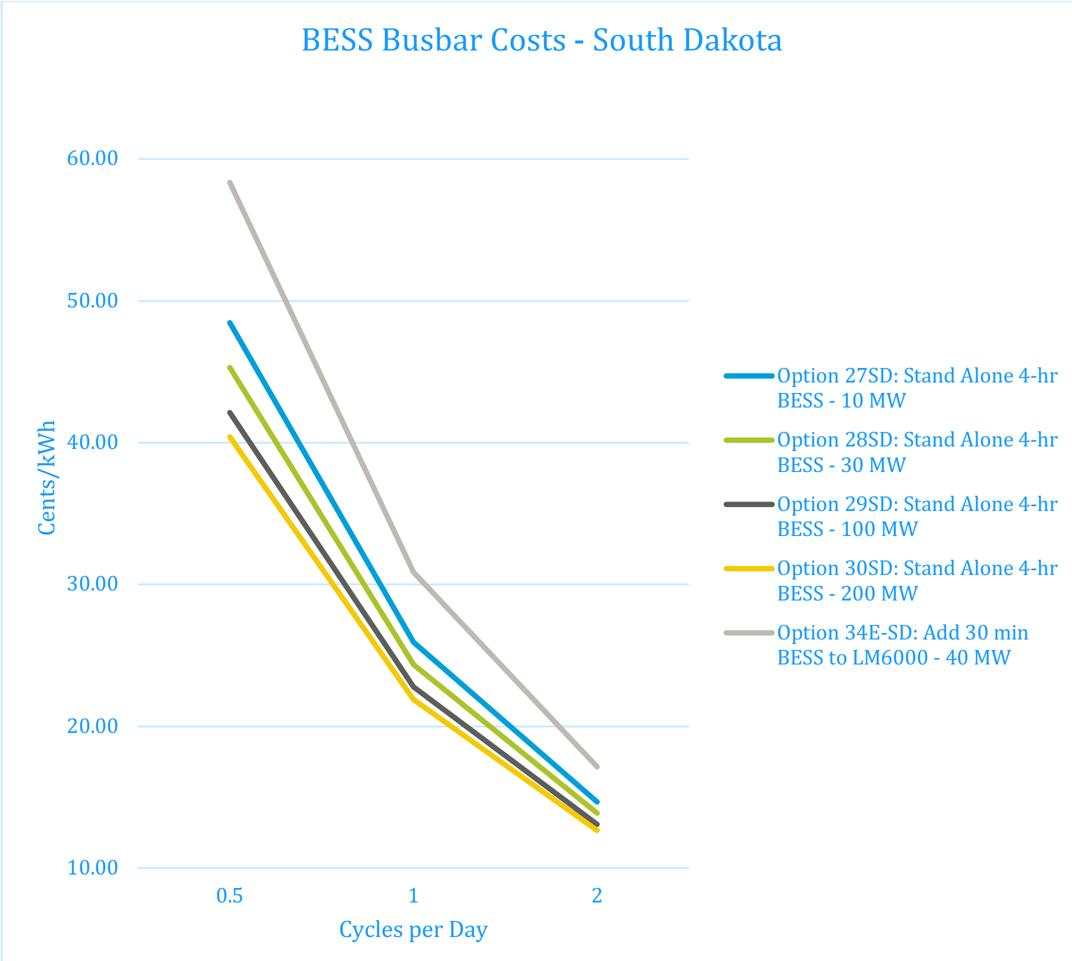

Figure 4-16 Busbar Costs for BESS Options in South Dakota

4.3 COLD RESERVE

Option 6, placing NS2 in cold reserve, would remove the unit from active service but would allow it to be brought back into service if feasible at a future time. No busbar costs are developed for this option as the unit would not be producing energy output when in cold reserve.

The cost of placing NS2 into cold reserves was estimated as an annual fixed O&M cost of $951,000/yr or $12.04 $/kW. This number is based on a reduced staff of 4.5 full time employees. Labor costs include 10 percent bonus and incentive pay but do not include overtime. There will be no variable O&M costs during the cold shutdown due to no run-time or operation related expenses. The fixed O&M costs were calculated on an annual basis with no designated end date; the costs are in 2021 dollars. The fixed O&M costs include costs for boiler, turbine, generator and feedwater systems cold storage layup.

For this calculation Black & Veatch assumed that the systems not required to run for cold storage on a frequent periodic basis will be deenergized at their breaker and critical equipment will be preserved in active status to minimize degradation and loss of equipment capability. Assumptions include that Black Hill's plant O&M staff will maintain equipment as if in operating "reserve shutdown" status and equipment maintenance will be performed on a condition-based process, meaning replacement is not performed on time basis. The cold layup process would require between 1 and 3 weeks to restore the unit back to service. Black & Veatch also assumed a minimal effort of installation and monitoring for nitrogen blanketing of designated equipment. Unit emissions testing will be waived during the cold storage period until unit is restored back to service.

4.4 NS2 RETIREMENT

Option 35 is the retirement of the NS2 coal-fired power plant. Black & Veatch did not create a busbar model for this option because the retirement of the NS2 plant would involve expenditures to take the unit out of operation and an annual fixed maintenance cost rather than the cost of producing energy. Black & Veatch calculated the annual fixed O&M costs for retirement to be $103,000/yr or $1.30 $/kW. This is based on a reduced staffing of 0.45 full time employees for minimum monitoring and safety repairs during retirement status. Labor costs assume 10 percent bonus and incentive pay but do not include overtime. There will be no variable O&M costs in that the unit will no longer run.

Black & Veatch assumed a cold shutdown of the unit for the retirement option, meaning it will be taken out of service with no chance to return to service. The costs of compliance separation/isolation are assumed to have been performed to disallow unit operation, but those costs are not included in our annual fixed O&M cost. Energy usage for lighting and equipment will be required for safety but those costs are not included in Black & Veatch's calculation.

Black & Veatch assumes the unit would remain in tack, meaning there would be minimal demolition, until a future decision is made to demolish a portion of, or all structures, but the equipment is assumed not to be preserved for future resale. It is assumed that common systems to other plant functions are isolated or relocated as required and isolation costs are not included in the provided fixed O&M cost. Costs for initial draining of lubricants, LOTO and other tasks to prepare unit for retirement are not included. Plant O&M staff will address safety issues only. Issues larger than can be addressed by plant staff will be contracted, nominal contract labor has been included. No equipment maintenance is to be performed. It is assumed that Boiler, Turbine, Generator, and Feedwater system long term layup has been discontinued and unit environmental permits have been modified for retirement status (costs not included).

5.0 Candidate Unit Screening Recommendations

In this section, the busbar results from Section 4 are used to recommend a list of screened options for BHP, for CLFP, and for the combined BHP plus CLFP areas. The recommendations are made according to base load, peaking, renewable energy, and other option categories. Some preliminary considerations are appropriate to point out before specific recommendations are made:

1. Generally, if a busbar cost curve of one option lies completely below the busbar cost curve of a competing option of the same technology group (base load, peaking, etc.), it is an indication that the higher cost option can be eliminated because it would cost more on a levelized cost basis across a wide range of capacity factors appropriate for the technology classification. However, there are some important exceptions to this general rule.

2. One exception concerns the size of units being compared and if there is a large difference in net output between two units, it could mean that the larger unit may operate at a much lower capacity factor compared to the smaller unit. For example, in the BHP base load analysis, Option 13 is a 444 MW combined cycle that is lower in cost than other new combined cycle facilities evaluated that had a range of 73 MW to 167 MW. Thus, to serve BHP load, it is possible that Option 13 would dispatch at a much lower capacity factor than any other option and this could distort comparisons of options using the busbar technique. As a general rule, Black & Veatch believes that this issue increasingly impacts busbar comparisons when the MW difference between two options is 50 percent or more.

3. Another important consideration that could result in the screening of a relatively large candidate unit such as Option 13 is the need for additional capacity by the utility. The need for additional capacity in an IRP is determined by comparing the peak load forecast for the utility plus a planning reserve margin to the available firm capacity available to the utility each year in the planning horizon. When the peak load forecast plus reserve margin exceeds the available firm capacity at the time of system peak, it can be an indication that additional capacity resources are needed on the system. An illustration of a capacity balance table is shown in Figure 5-1.

2021-2040 Capacity Balance											
	Load + Reserves			Capacity Resouces							Capacity Balance
	Load	Reserves									
	Peak Load	Reserves @ 15%	System Demand + Reserves	Self-Owned	Hydro Firm PPA	IPP PPA	IPP 2 PPA	Dist. Gen.	Other Firm	Total Capacity	MW Surplus or Deficit
2021	1,534	230	1764	1500	260	40	75	0		1,875	111
2022	1,542	231	1773	1500	260	40	175	0	0	1,975	202
2023	1,670	250	1920	1500	260	40	200	20	0	2,020	100
2024	1,740	261	2000	1500	260	40	200	20	45	2,065	65
2025	1,787	268	2055	1200	260	40	200	20	45	1,765	(290)
2026	1,823	273	2096	1200	260	40	200	20	45	1,765	(331)
2027	1,850	277	2127	1200	260	40	200	20	45	1,765	(362)
2028	1,873	281	2154	1200	260	40	200	20	45	1,765	(389)
2029	1,853	278	2131	1200	260	40	200	20	45	1,765	(366)
2030	1,874	281	2155	1200	260	40	200	20	45	1,765	(390)
2031	1,892	284	2176	1200	260	40	200	20	45	1,765	(411)
2032	1,860	279	2139	1200	260	40	200		45	1,745	(394)
2033	1,879	282	2161	1200	260	40	200		45	1,745	(416)
2034	1,899	285	2184	1200	260	40	200		45	1,745	(439)
2035	1,919	288	2207	1050	260	40	200		45	1,595	(612)
2036	1,895	284	2179	1050	260	40			45	1,395	(784)
2037	1,912	287	2198	1050	260	40			45	1,395	(803)
2038	1,928	289	2217	1050	260	40			45	1,395	(822)
2039	1,945	292	2236	1050	260	40			45	1,395	(841)
2040	1,961	294	2255	1050	260	40			45	1,395	(860)

Figure 5-1 Hypothetical Capacity Balance

A rule of thumb followed by many utilities is that if a new unit is added to a system, the utility should "grow into" the new capacity (in other words, the excess capacity on a capacity balance should fall to zero) within a five to seven-year time frame. An exception could arise if the projected market conditions were favorable such that the excess unit capacity could be sold in the market over the long-term at a profit, but many regulated utilities and regulators view it risky to build what is considered "merchant capacity" in the hopes of earning a profit on capacity not needed to meet the utility's own capacity planning obligations.

Since the development of a capacity balance for BHP and CLFP is not part of this scope, the determination of a reasonable maximum unit size and a projection of how long it takes to grow into the capacity of the larger units considered in this study is not made in this report. However, the issue can be revisited by BHP as the long-term forecast and capacity balance becomes available going forward. The five to seven-year guideline can be used to determine whether the larger units considered in this analysis would be an appropriate fit for BHP, CLFP, or on a combined basis.

It is also possible that a large unit may not be pursued, even if it is the most economical and passes the five to seven-year guideline, if the unit would use a significant amount of the borrowing capacity or equity funding available to the utility if there are other competing projects for the capital.

4. Another consideration when developing a screened unit list for an IRP is that while new candidate units add capacity to a utility system, there are several conversion options evaluated in this report that add only a limited amount of incremental system capacity. Thus, it is important to view busbar results with consideration of whether capacity being added meets the need for new capacity required or if the candidate option would largely result in an efficiency and environmental improvement.

5. Finally, it is also recognized that some options such as renewable energy candidate projects and carbon reduction projects may be adopted to meet environmental targets, even if they are not strictly competitive on a busbar cost or total cost basis. This means that a renewable energy project could be selected if it is not the least cost option but is needed to achieve targeted renewable energy levels or emission reduction levels.

5.1 BASE LOAD OPTION SCREENING

This section discusses the base load option screening for BHP, CLFP, and the combined service areas. Use is made of the figures developed in Section 4.

5.1.1 Base Load Option Screening for BHP

Table 5-1 and Figure 5-2 are reproduced from The busbar results for the conventional natural gas base load options are shown in Table 4-2 for the candidate units for the BHP service area in South Dakota (for purposes of natural gas pricing a location in Rapid City is assumed), and in Table 4-3 for the candidate units for the CLFP service area in Wyoming (assumed to be at the Neil Simpson Complex (NSC) in Gillette, or at the Cheyenne Prairie Generating Station (CPGS), Wyoming). In these tables, options that can be installed either in South Dakota or Wyoming are identified with "SD" or "W", respectively, following the option number, such as Option 13SD or Option 13W. Figure 4-3 and Figure 4-4 present the resulting busbar curves that correspond to the conventional BHP or CLHP base load options tables.

Table 4-2 and Figure 4-3 and show the base load options for BHP. Option 13SD has the lowest busbar cost by a wide margin and, at this point, the option should be carried forward to the full IRP. However, this option may be too large for BHP's needs; this can be determined through the IRP capacity balance for BHP that will indicate the need for power and the ability of BHP to grow into the 444 MW of capacity should Option 13SD be selected. Once the capacity balance for BHP is known and the excess capacity on the BHP system associated with Option 13SD is determined, the question for the BHP planning staff is whether the excess capacity and possible reliance on market revenues with Option 13SD would eliminate it as a selected resource option even if it were part of the least cost plan.

Given the uncertainty associated with Option 13SD, it is recommended that two other combined cycle options from Figure 5-2 should also be carried forward to the full IRP. The option having the next lowest cost is the 167 MW unit, Option 14SD. This option is recommended for the full IRP. The final option to be carried forward would be Option 15SD in terms of busbar costs. However, in the event that BHP does not grow into this capacity within five years, based on the BHP capacity balance, Option 17SD could be substituted for Option 15SD.

Table 5-1 Busbar Costs for Natural Gas Base Load Options for the BHP Service Area in South Dakota

UNIT	CAPACITY FACTOR					
	40%	50%	60%	70%	80%	90%
Option 13SD: 444 MW - 1x1 7HA.02 CC w/o DF	8.22	7.39	6.83	6.43	6.14	5.90
Option 14SD: 167 MW - 3x1 LM6000 PF+ CC w/o DF	12.19	10.67	9.65	8.92	8.38	7.95
Option 15SD: 111 MW - 2x1 LM6000 PF+ CC w/o DF	12.96	11.30	10.20	9.41	8.82	8.36
Option 17SD: 73 MW - 1x1 LM6000 PF+ CC with DF	13.35	11.74	10.67	9.90	9.33	8.88

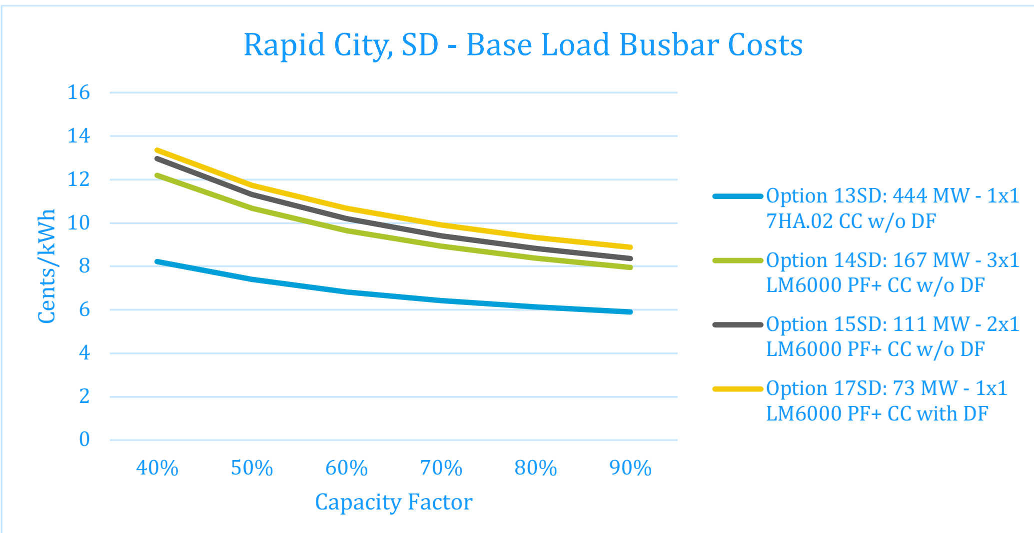

Figure 5-2 Busbar Curves for Natural Gas BHP Base Load Options in South Dakota

5.1.2 Base Load Option Screening for CLFP

Table 5-2 and Figure 5-3 are reproduced from Table 4-3 and Figure 4-4 and show the base load options for CLFP. Option 13W has the lowest busbar cost by a wide margin and, at this point, the option should be carried forward to the full IRP. However, this option could be eliminated after the CLFP capacity balance is derived for the same reasons that apply to BHP; namely, if CLFP does not grow into the unit capacity within five to seven years and if there is market risk or financing limits that would be considered a fatal flaw, even if the system economics appear favorable for the unit.

From Figure 5-3, the following options are also recommended to be carried forward:

- Option 9 – 97 MW conversion of CPGS CT2 to a 2x1 combined cycle with wet cooling
- Option 10W – 96 MW conversion of CPGS CT2 to a 2x1 combined cycle with dry cooling
- Option 14W – 147 MW, 3x1 combined cycle using LM6000 technology without duct firing

This combination allows for the consideration of converting CT2 to combined cycle mode with dry and wet cooling although, if water usage is not an issue of significance, Option 10W could potentially be screened out. Including Option 14W also allows the inclusion of a new facility for consideration along with the two other conversion options. Option 14W also includes approximately 50 percent more capacity and the value of this additional capacity can be evaluated through the capacity balance analysis and the detailed production costing modeling.

Table 5-2 Busbar Costs for Natural Gas Base Load Options for the CLFP Service Area in Gillette and Cheyenne, Wyoming

	CAPACITY FACTOR					
UNIT	40%	50%	60%	70%	80%	90%
Option 7: 102 MW – NSC CT1 (LM6000 PD) Convert to 2x1 Wet CC	10.52	9.32	8.52	7.95	7.53	7.19
Option 8: 101 MW – NSC CT1 (LM6000 PD) Convert to 2x1 Dry CC	10.84	9.59	8.76	8.17	7.72	7.37
Option 9: 97 MW – CPGS CT2 (LM6000 PF) Convert to 2x1 Wet CC	10.03	8.79	7.96	7.36	6.92	6.57
Option 10: 96 MW – CPGS CT2 (LM6000 PF) Convert to 2x1 Dry CC	10.33	9.03	8.17	7.55	7.08	6.72
Option 13W: 444 MW - 1x1 7HA.02 CC w/o DF at CPGS	7.38	6.55	5.99	5.59	5.29	5.06
Option 14W: 167 MW - 3x1 LM6000 PF+ CC w/o DF at CPGS	11.25	9.72	8.71	7.98	7.43	7.01
Option 15W: 111 MW - 2x1 LM6000 PF+ CC w/o DF at CPGS	12.02	10.36	9.25	8.47	7.87	7.41
Option 16: 112 MW - 2x1 LM6000 PF+ CC w/o DF at CPGS	11.95	10.31	9.21	8.43	7.84	7.39
Option 17W: 73 MW - 1x1 LM6000 PF+ CC with DF at CPGS	12.30	10.69	9.62	8.86	8.28	7.83

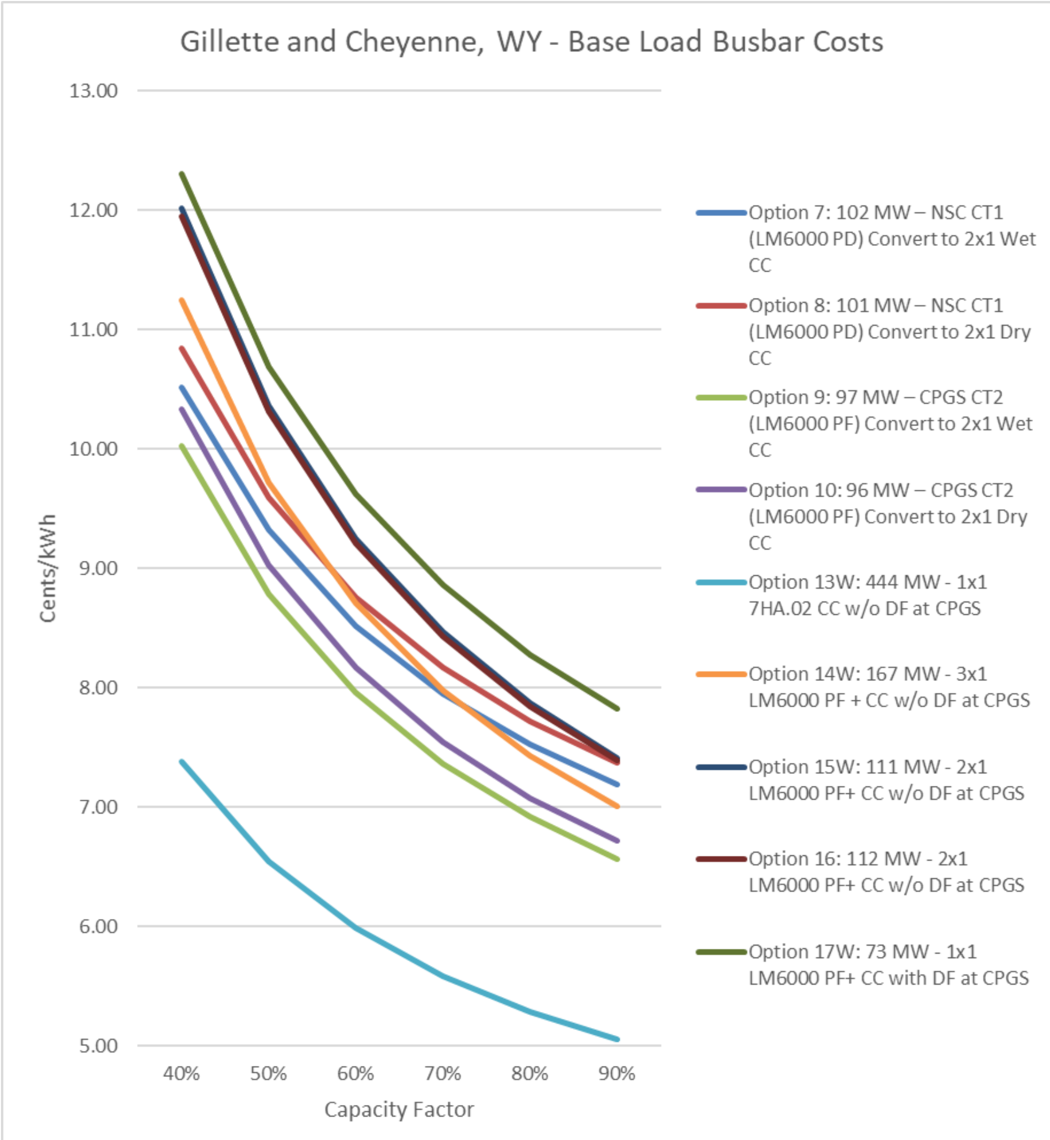

Figure 5-3 Busbar Curves for Natural Gas Base Load Options in Gillette and Cheyenne, Wyoming

5.1.3 Screening of Other Base Load Options

Table 5-3 and Figure 5-4 are reproduced from Table 4-4 and Figure 4-5 and show busbar costs for two coal options and a small scale nuclear unit assumed to be available after 2030. Option 2 has an extremely high cost and this coal option can be screened from further consideration. Option 5 reflects the levelized costs of projects recommended to allow NS2 to reach the end of its published end of life date of 2039. These Black & Veatch identified projects are in addition to projects already identified. Due to the relatively low cost of these incremental projects, Option 5 should be carried forward to the detailed analysis. Option 33 is the small-scale nuclear unit and it would not be an option until after 2030. The unit is not competitive with combined cycle base load options as Option 33 has a busbar cost at a 90 percent capacity factor of 10.75 cents/kWh (from Table 4-4) compared to three combined cycle options having a busbar cost below 7 cents/kWh (from Figure 5-3 and Table 4-3). It is therefore recommended that Option 33 be screened from further consideration although it should be revisited as a candidate option in future IRP studies and in high decarbonization scenarios. Option 4 can be retained at this stage in the analysis. Although it has a somewhat higher busbar cost at high capacity factors compared to new combined cycle options, it has a fairly low cost at lower capacity factors.

Table 5-3 Busbar Costs for Other Base Load Options

UNIT	CAPACITY FACTOR					
	40%	50%	60%	70%	80%	90%
Option 1: 100 MW (90%) Carbon Capture System Installed at Existing 100 MW Unit in Gillette	22.27	18.25	15.57	13.66	12.22	11.11
Option 2: New 500 MW Supercritical Coal Plant with CO_2 Capture	42.65	34.50	29.07	25.20	22.29	20.02
Option 4: 80-100 MW Coal to Gas Conversion Unit	8.98	8.61	8.36	8.19	8.05	7.95
Option 5: 80-100 MW Coal Plant Life Extension	12.16	10.09	8.71	7.73	6.99	6.41
Option 33: 100 MW SMR	22.90	18.52	15.61	13.52	11.96	10.75

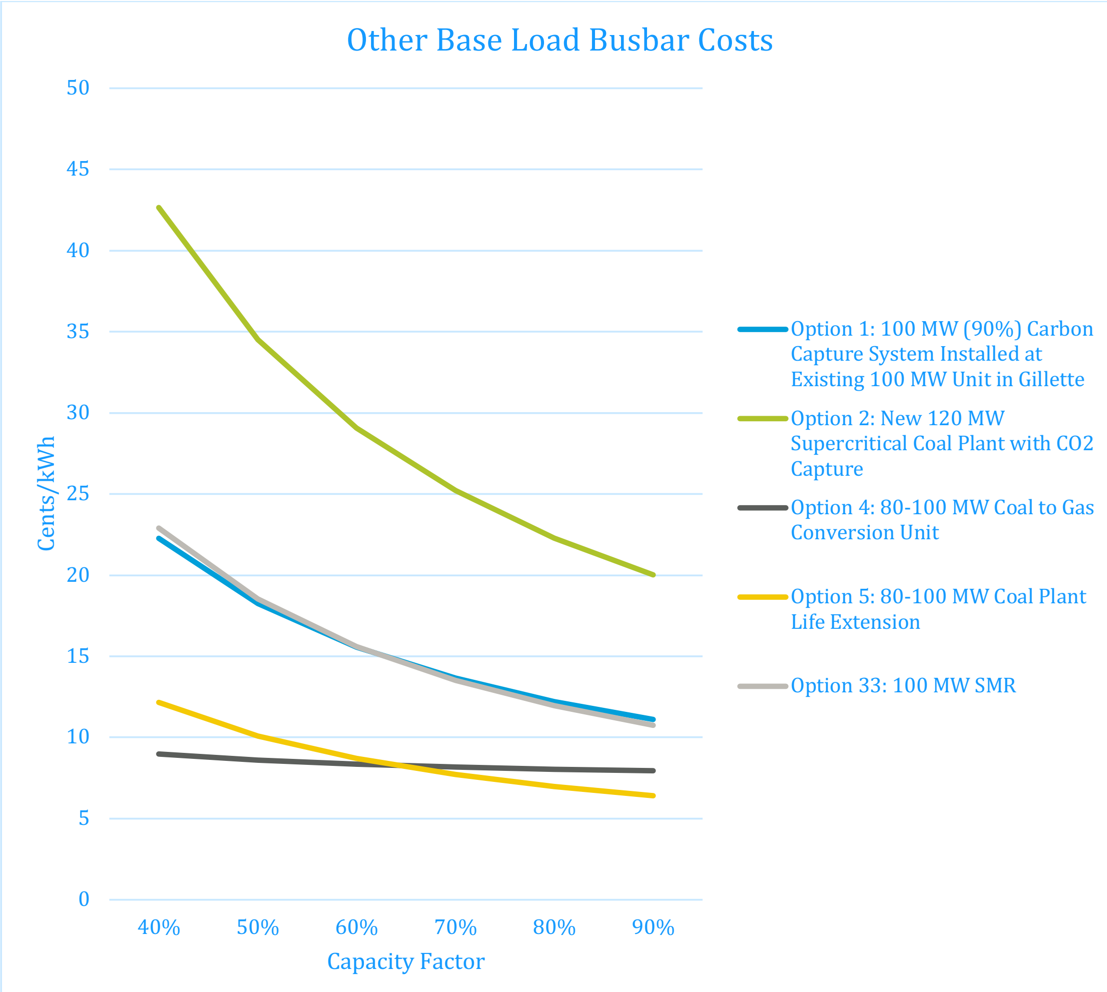

Figure 5-4 Busbar Curves for Coal Plants and SMR Base Load Options

5.1.4 Screening of Renewable Base Load Options

Table 5-4 and Figure 5-5 are reproduced from Table 4-5 and Figure 4-6 and present the levelized busbar costs for a base load biomass facility and a geothermal facility. Both options have a levelized cost at a 90 percent capacity factor of over 15 cents/kWh, or more than two times the levelized cost of gas-fired baseload options available to CLFP and some 7 cents/kWh higher than base load options available to BHP; this does not include the large combined cycle (Option 13) that is below 6 cents/kWh at a 90 percent capacity factor for both utilities. From an economic standpoint, the decision would be to screen out Option 31 and Option 32.

The one consideration that would favor carrying forward at least one of these options is that they are renewable options that could contribute toward environmental objectives. However, given the low-cost renewable alternatives of solar and wind available, it is very likely that environmental objectives can be achieved at a lower cost than with the geothermal and biofuel plants. There is also considerable risk associated with Option 31 in terms of reliable and sufficient biomass fuel supplies that would allow for base load operation and, in the case of geothermal, the location of a satisfactory geothermal resource and the funds required to prove and develop the geothermal resource.

Table 5-4 Busbar Costs for Renewable Base Load Options

UNIT	CAPACITY FACTOR					
	40%	50%	60%	70%	80%	90%
Option 31: 100 MW Biofuel Plant	27.32	22.94	20.02	17.93	16.37	15.15
Option 32: 40MW Geothermal	34.65	27.72	23.10	19.80	17.32	15.40

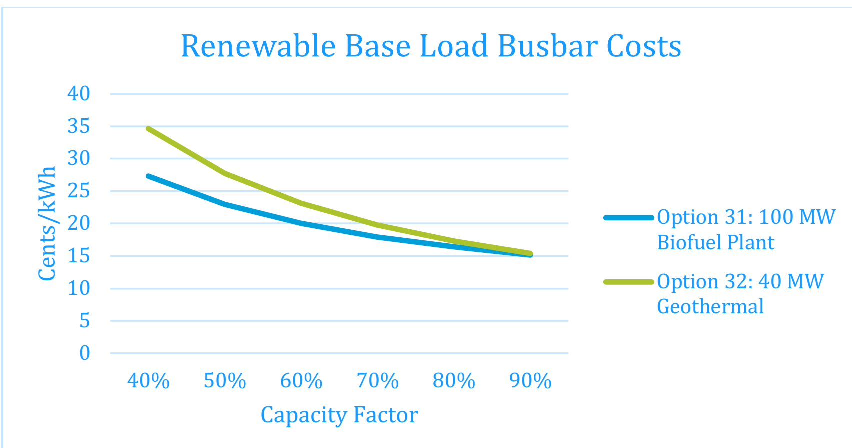

Figure 5-5 Busbar Curves for Renewable Base Load Options

5.1.5 Screening of Peaking Options for BHP

Table 5-5 and Figure 5-6 are reproduced from Table 4-6 and Figure 4-7 and present the levelized busbar costs for BHP peaking options. From the list of candidates, Option 11 is a low-cost conversion option involving fuel switching that would provide environmental and economic benefits, but the option will not materially impact the BHP capacity balance. The project should be carried forward to the full IRP. The remaining BHP peaking options include 42 MW, 75 MW, and 91 MW options. This is a good MW range of options and potentially all could be carried forward to the full IRP, depending on the capacity balance results and the need for power. However, it is also possible to screen out the 75 MW option as it has a higher busbar cost than the small 42 MW unit and the 91 MW unit. Since two 42 MW units could be added to equal approximately one 75 MW unit if this is the capacity needed from the capacity balance, it is recommended that Option 20SD be screened from further consideration.

Table 5-5 Busbar Costs for Peaking Options in Rapid City, South Dakota

UNIT	CAPACITY FACTOR			
	5%	15%	25%	35%
Option 11: Convert 10 MW Diesel to Natural Gas	19.78	11.19	9.47	8.73
Option 18SD: 91 MW - 1x0 LMS100 CT	50.18	20.51	14.57	12.03
Option 19SD: 42 MW - 1x0 LM6000 PF+ CT	63.49	25.38	17.76	14.50
Option 20SD: 75 MW - 1x0 7EA CT	64.53	26.43	18.81	15.54

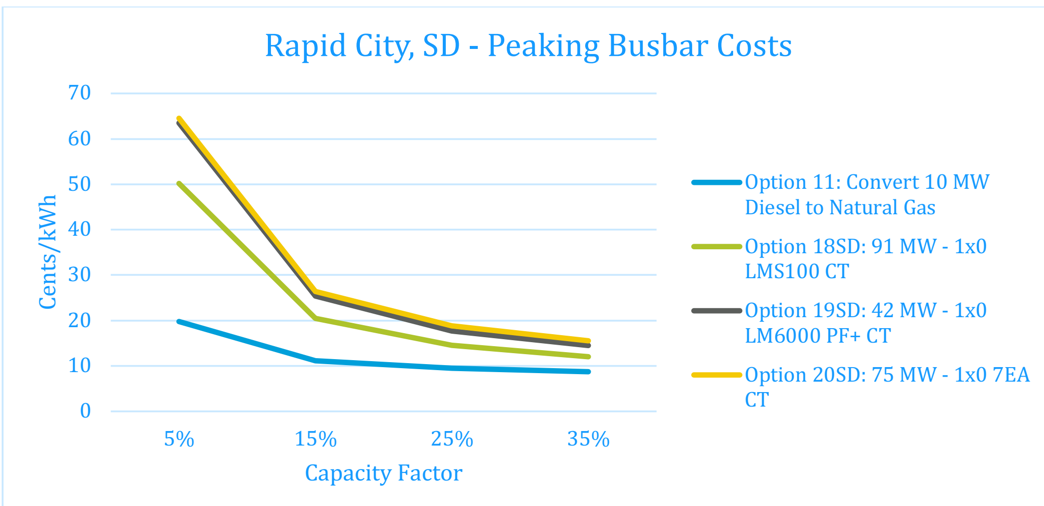

Figure 5-6 Busbar Curves for Peaking Options in Rapid City, South Dakota

Table 5-6 and Figure 5-7 shows the peaking options for the CLFP service area. These are reproduced from Table 4-7 and Figure 4-8. It is recommended that Option 18W and Option 19W be carried forward to the full IRP while Option 20W be screened from further consideration as it is more costly that the other peaking options. Option 3, while not the lowest cost option, has environmental benefits and the full IRP modeling can capture this benefit; it is recommended that Option 3 be carried forward.

Table 5-6 Busbar Costs for Peaking Options in Cheyenne, Wyoming

UNIT	CAPACITY FACTOR 5%	15%	25%	35%
Option 3: Conversion of LM6000 CT to Burn 35% Hydrogen Blend	27.17	17.47	15.53	14.70
Option 18W: 91 MW - 1x0 LMS100 CT	49.01	19.34	13.4	10.86
Option 19W: 42 MW - 1x0 LM6000 PF+ CT	62.23	24.13	16.51	13.24
Option 20W: 75 MW - 1x0 7EA CT	63.04	24.93	17.31	14.04

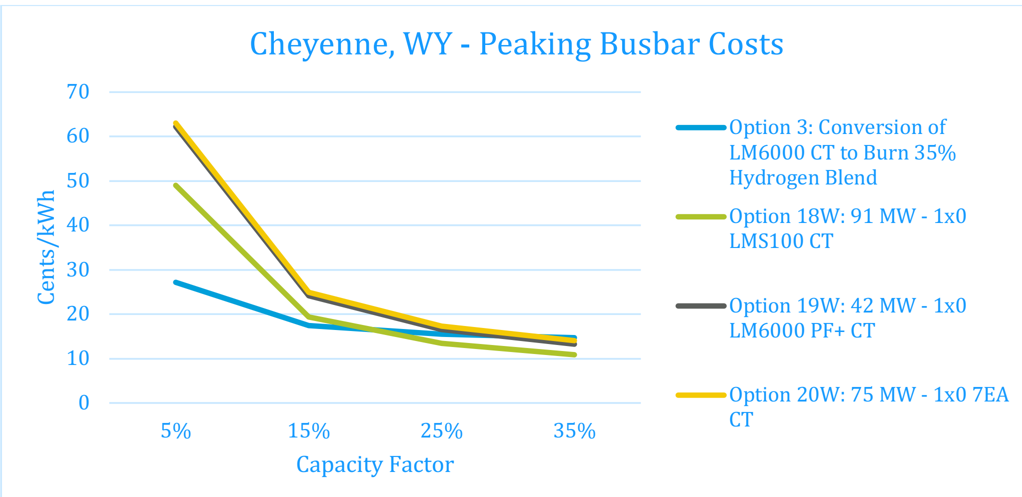

Figure 5-7 Busbar Curves for Peaking Options in Cheyenne, Wyoming

5.1.6 Screening of Solar Options for CLFP

Table 5-7 and Figure 5-8 show three solar options for Gillette, Wyoming and are a reproduction of Table 4-8 and Figure 4-9. Table 5-8 and Figure 5-9 show three solar options for Cheyenne, Wyoming and are a reproduction of Table 4-10 and Figure 4-11. There is a wide range of capacities in these options, ranging from 50 MW to 200 MW. While the lowest bus-bar cost is associated with the 200 MW unit, it is not apparent at the screening level how much solar and renewable additions are optimal for the system or may be required in combination with other renewable options to meet environmental targets. It is recommended that all six solar options in Wyoming be carried forward to the IRP evaluation.

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Table 5-7 Busbar Costs for Solar Options in Gillette, Wyoming

UNIT	CAPACITY FACTOR 15.7%	18.7%	21.7%
Option 21GW: 200 MW Solar PV SAT	11.63	9.76	8.41
Option 22GW: 100 MW Solar PV SAT	11.86	9.96	8.58
Option 23GW: 50 MW Solar PV SAT	12.26	10.30	8.87

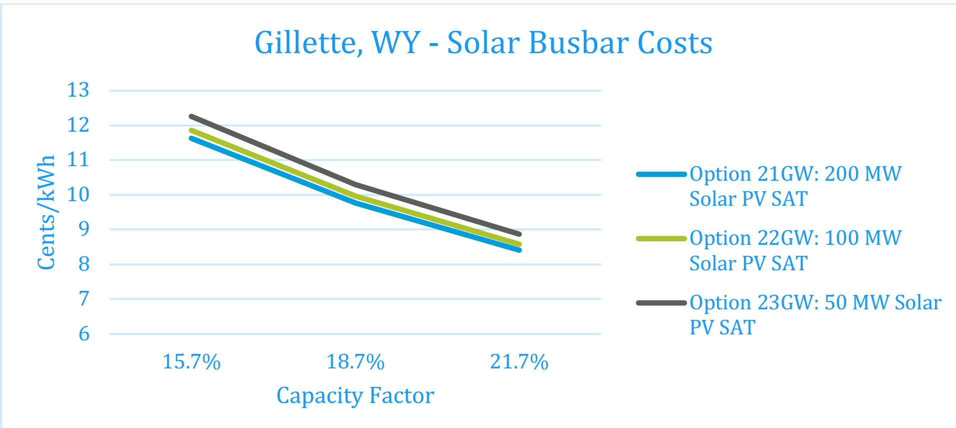

Figure 5-8 Busbar Curves for Solar Options in Gillette, Wyoming

Table 5-8 Busbar Costs for Solar Options in Cheyenne, Wyoming

UNIT	CAPACITY FACTOR 17.1%	20.1%	23.1%
Option 21CW: 200 MW Solar PV SAT	10.68	9.08	7.90
Option 22CW: 100 MW Solar PV SAT	10.89	9.27	8.06
Option 23CW: 50 MW Solar PV SAT	11.26	9.58	8.33

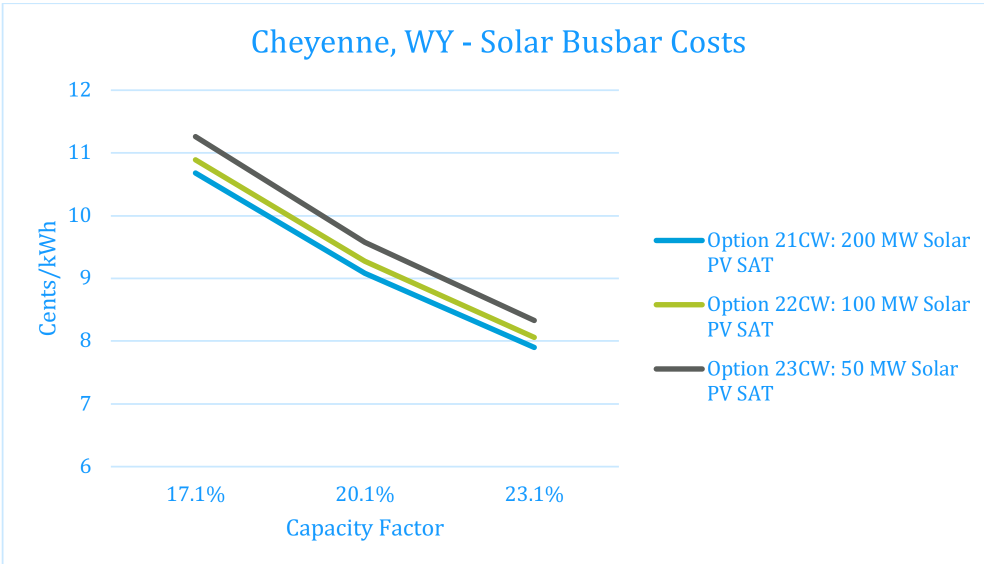

Figure 5-9 Busbar Curves for Solar Options in Cheyenne, Wyoming

5.1.7 Screening of Solar Options for BHP

Table 5-9 and Figure 5-10 are a reproduction of Table 4-9 and Figure 4-10 and show solar options for the BHP service area. All three of these options are recommended to be carried forward to the IRP for the same reasons explained for the CLFP solar options.

Table 5-9 Busbar Costs for Solar Options in Hot Springs, South Dakota

UNIT	CAPACITY FACTOR		
	18.6%	21.6%	24.6%
Option 21SD: 200 MW Solar PV SAT	9.81	8.45	7.42
Option 22SD: 100 MW Solar PV SAT	10.01	8.62	7.57
Option 23SD: 50 MW Solar PV SAT	10.35	8.91	7.83

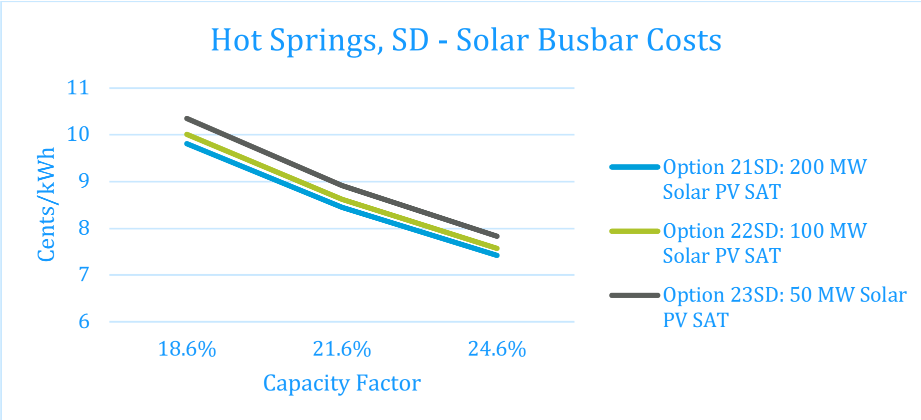

Figure 5-10 Busbar Curves for Solar Options in Hot Springs, South Dakota

5.1.8 Wind Option Screening for Cheyenne, Gillette and Douglas, Wyoming

Three sites were identified in Wyoming as potential wind generation sites and total wind capacity installations of 50 MW, 100 MW, and 200 MW were modeled at each site. The relative economics of these options are driven by the projected capacity factor, which is highest for the Cheyenne location, followed by Gillette, and then Douglas, Wyoming. The best wind resources are located in Cheyenne (45.06 percent expected capacity factor), followed by Douglas (42.42 percent expected capacity factor) and Gillette (39.66 percent expected capacity factor). While it is possible that a large (200 MW) wind facility could provide the wind resources needed, it is also possible that there could be different hourly production profiles between wind generation at two sites, and this could be beneficial from an economic perspective. Therefore, it recommended that all three size options be carried forward for the Cheyenne wind site and for the Douglas wind site, but that the Gillette wind option be screened from further consideration.

The wind options in Cheyenne are shown in Table 5-10 and Figure 5-11, these are a reproduction of Table 4-11 and Figure 4-12 . The wind options in Gillette are shown in Table 5-11 and Figure 5-12, these are a reproduction of Table 4-12 and Figure 4-13. The wind options in Douglas are shown in Table 5-12 and Figure 5-13, these are a reproduction of Table 4-13 and Figure 4-14 .

Table 5-10 Busbar Costs for Wind Options in Cheyenne, Wyoming

UNIT	CAPACITY FACTOR		
	42.06%	45.06%	48.06%
Option 24CW: 200 MW Wind	5.14	4.80	4.50
Option 25CW: 100 MW Wind	5.27	4.92	4.61
Option 26CW: 50 MW Wind	5.34	4.98	4.67

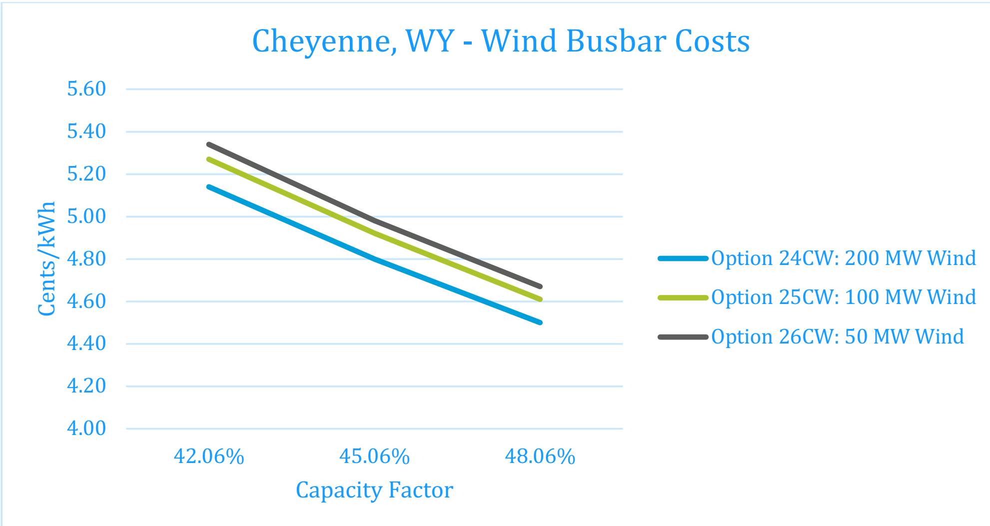

Figure 5-11 Busbar Curves for Wind Options in Cheyenne, Wyoming

Table 5-11 Busbar Costs for Wind Options in Gillette, Wyoming

UNIT	CAPACITY FACTOR		
	36.66%	39.66%	42.66%
Option 24GW: 200 MW Wind	5.90	5.46	5.07
Option 25GW: 100 MW Wind	6.04	5.59	5.19
Option 26GW: 50 MW Wind	6.12	5.66	5.26

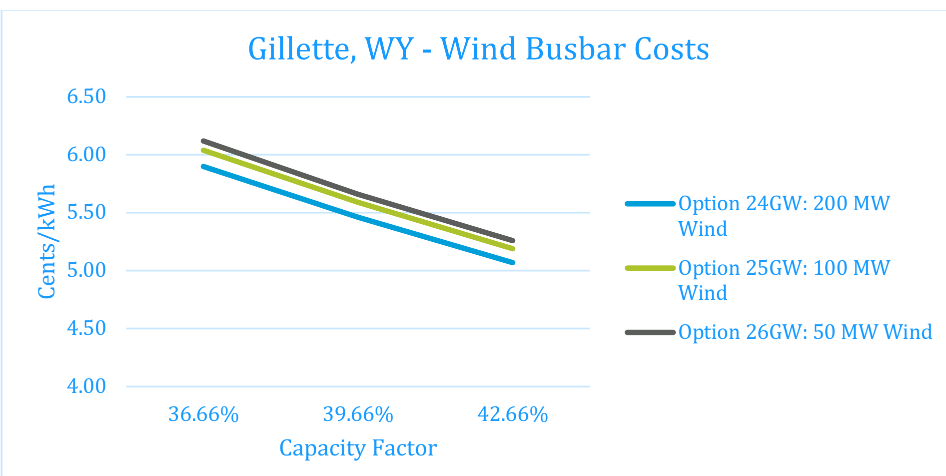

Figure 5-12 Busbar Curves for Wind Options in Gillette, Wyoming

Table 5-12 Busbar Costs for Wind Options in Douglas, Wyoming

UNIT	CAPACITY FACTOR		
	39.42%	42.42%	45.42%
Option 24DW: 200 MW Wind	5.49	5.10	4.76
Option 25DW: 100 MW Wind	5.62	5.22	4.88
Option 26DW: 50 MW Wind	5.69	5.29	4.94

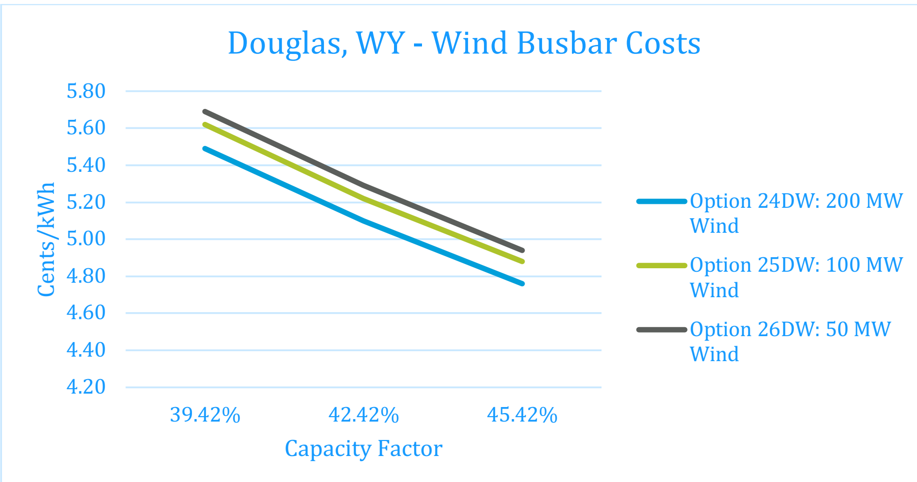

Figure 5-13 Busbar Curves for Wind Options in Douglas, Wyoming

5.1.9 BESS Technology Screening

Greenfield BESS options were modeled in Wyoming and South Dakota. The uses modeled would allow BESS to be used as a source of peaking power, to provide ancillary services such as frequency regulation or reserves, and to work in tandem with existing LM6000 capacity so that the LM6000 capacity can be considered almost immediately available when called upon to deliver power or ancillary services. Figure 5-14 and Figure 5-15, reproduced from Figure 4-15 and Figure 4-16 in Section 4, show the busbar cost curves based on 0.5, 1, or 2 average charging and discharging cycles per day. Due to the number of configurations involved, Table 5-13 and Table 5-14, which are the basis of the busbar curves, are reproduced from Table 4-14 and Table 4-15 in Section 4.

Generally speaking, with the decreasing costs and increased performance of BESS, the power industry has only in recent years carefully studied the full potential of the technology to provide power and ancillary services. In recent studies where Black & Veatch has compared BESS to combustion turbine technology to provide frequency regulation or spinning reserve ancillary services, the BESS has been found to be more economical than CT alternatives that, depending on the ancillary service provided, must be spinning and consuming fuel. Consistent with the intent of options in this study to add 30 minute BESS to LM6000 units, BESS is also being recognized as a cost-effective means of increasing the value of existing gas-fired units to provide ancillary services and to be more flexible in response to dispatch requirements.

Due to the increasing role of BESS, it is recommended that most of the options for the CLFP and BHP systems be carried forward and their value carefully determined in integrated computer modeling that values the added flexibility to provide power and ancillary services. For the Wyoming options, the first five options in Table 5-13, highlighted in yellow, are four-hour options that range in size from 10 MW to 200 MW. It is recommended that all five options be carried forward to evaluate the competitiveness and optimum size of the BESS technology. However, unless Option 12 and Option 27W will be distinguished from one another in the modeling process, one of these can be eliminated and the planning program can be allowed to select more than one 10 MW BESS option.

The second set of five options, highlighted in blue, involve adding 30 minutes of BESS production capability to work in tandem with LM6000 units with capacities ranging from 40 MW to 137 MW. Again, it is concluded that carrying forward a wide range of the 30-minute BESS options will allow the detailed IRP work to more precisely determine the value of BESS options of various sizes on the CLFP system. It appears, however, that only one of Option 34B and Option 34C would need to be carried forward to the detailed modeling. Thus, the BESS screening results in a recommendation that 8 of the 10 options for Wyoming be carried forward to the detailed modeling.

Table 5-13 Busbar Costs for BESS Options in Wyoming

UNIT	CYCLES PER DAY		
	0.5	1	2
Option 12: 10 MW 4-hr BESS as Diesel Replacement	47.60	25.07	13.81
Option 27W: Stand Alone 4-hr BESS - 10 MW	47.60	25.07	13.81
Option 28W: Stand Alone 4-hr BESS - 30 MW	44.44	23.49	13.02
Option 29W: Stand Alone 4-hr BESS - 100 MW	41.26	21.90	12.22
Option 30W: Stand Alone 4-hr BESS - 200 MW	39.55	21.05	11.79
Option 34A: Add 30 min BESS to LM6000 - 137 MW	53.11	27.82	15.18
Option 34B: Add 30 min BESS to LM6000 - 100 MW	54.19	28.37	15.45
Option 34C: Add 30 min BESS to LM6000* - 100 MW	54.19	28.37	15.45
Option 34D: Add 30 min BESS to LM6000 - 56 MW	56.25	29.40	15.97
Option 34E-W: Add 30 min BESS to LM6000 - 40 MW	57.49	30.02	16.28
Note* Option 34B is the 100MW LM6000 and Option 34C is the 100 MW LM6000 at CPGS.			

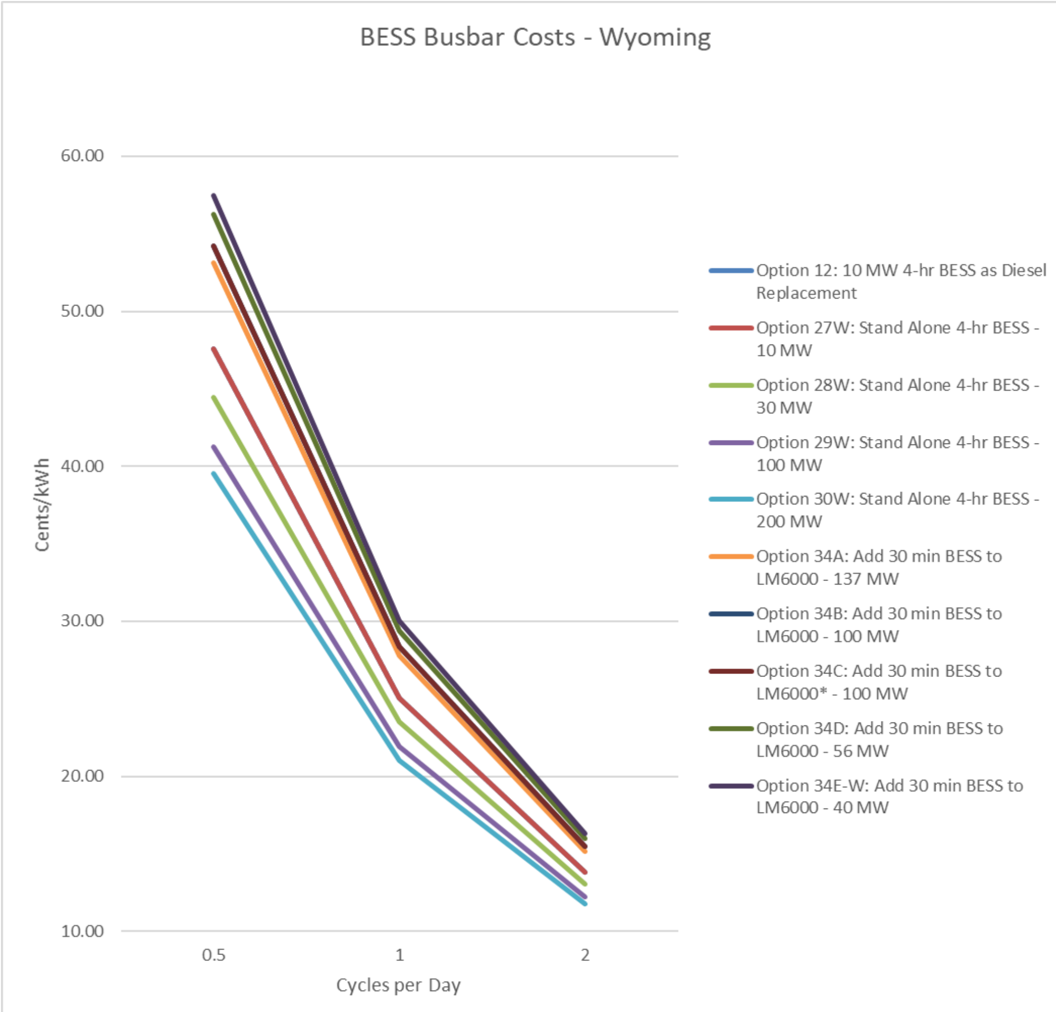

Figure 5-14 Busbar Costs for BESS Options in Wyoming*

Note* In Figure 5-14 Option 12 has the same exact costs as Option 27W, and Option 34B has the same exact costs as Option 34C so not all curves are visible.

The BESS options for South Dakota are presented in Table 5-14 and Figure 5-15. The options reflect the strategy of using BESS as a means of providing peaking power and of working in tandem with an LM6000 to increase the responsiveness and value of the LM6000 unit. The four options involving a 4-hour BESS discharge capability cover a wide range from 10 MW to 200 MW and it will be useful to evaluate the value of this range of options in the detailed modeling. It is recommended that all BESS options for South Dakota be carried forward to the detailed modeling, where the value of candidate BESS options to provide power and ancillary services in conjunction with other system units can best be determined.

Table 5-14 Busbar Costs for BESS Options in South Dakota

UNIT	CYCLES PER DAY 0.5	1	2
Option 27SD: Stand Alone 4-hr BESS - 10 MW	48.46	25.93	14.66
Option 28SD: Stand Alone 4-hr BESS - 30 MW	45.30	24.35	13.87
Option 29SD: Stand Alone 4-hr BESS - 100 MW	42.12	22.76	13.08
Option 30SD: Stand Alone 4-hr BESS - 200 MW	40.41	21.90	12.65
Option 34E-SD: Add 30 min BESS to LM6000 - 40 MW	58.35	30.87	17.14

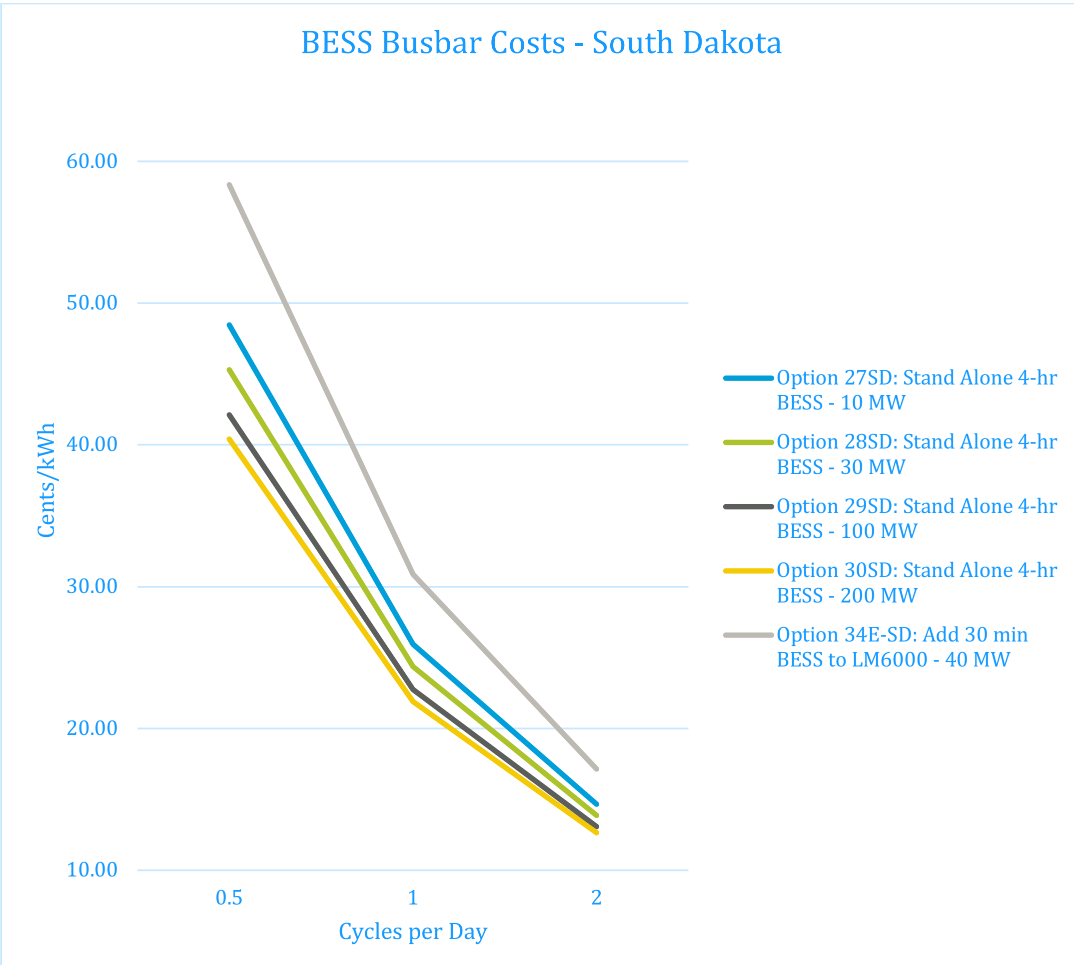

Figure 5-15 Busbar Costs for BESS Options in South Dakota

5.1.10 Other Options

Three options did not involve busbar cost curves: Option 1, the carbon capture option; Option 6, the placement of NS2 into cold reserves; and Option 35, the retirement of NS2. These options would impact, not only the cost of providing power, but also the achievement of system-wide environmental goals related to emission reductions. The value of these options is best determined through detailed modeling and it is recommended that all three options be carried forward to the IRP modeling phase.

It may well be that Option 1, with a capital cost of more than $300 million, will be quickly dropped from consideration once alternative expansion plans are developed to achieve emission reduction targets. Nevertheless, Option 1 can be initially carried forward as one strategy to achieve emission reduction targets and it will provide a benchmark against which other plans can be compared.

Under Option 6, NS2 will not be dispatching to serve load under normal circumstances and a cost of keeping the unit in cold storage will apply. The value in this option can be estimated in the detailed modeling through the development of sensitivity plans that, for example, would involve higher load growth than anticipated that could mean it becomes economical to remove NS2 from cold reserves. It is noted, however, that Option 1 and Option 6 do have certain associated risks. For example, there are potential (legal) risks associated with the effectiveness of carbon capture options, and there are risks that any future effort to bring NS2 out of cold storage could face environmental opposition. These factors may lead to the elimination of Option 1 and Option 6 in the detailed planning phase, but these considerations are outside of the busbar cost and cost development work performed in this study.

5.1.11 Recommended Options for the Detailed IRP Modeling Phase

Based on the previous recommendations in Section 5, Table 5-15 provides the list of recommended options to be carried forward to the detailed IRP modeling. Eleven of the 35 options in the study list are recommended to be eliminated from further consideration and not carried forward to the detailed IRP modeling.

Table 5-15 Option Recommendations

OPTION NUMBER AND DESCRIPTION	BUSBAR PERFORMED (Y/N)	OTHER TYPE OF ANALYSIS	CARRY FORWARD?
Option 1: A 100 MW carbon capture addition to existing 100 MW units in Gillette (NS2).	Yes		Yes, initially
Option 2: A new supercritical coal plant with carbon capture.	Yes		No
Option 3: A conversion of LM6000 CT to burn 30 percent - 50 percent hydrogen blend.	Yes		Yes
Option 4: An 80-100 MW coal to gas conversion unit.	Yes		Yes
Option 5: An 80-100 MW coal plant life extension.	Yes		Yes

OPTION NUMBER AND DESCRIPTION	BUSBAR PERFORMED (Y/N)	OTHER TYPE OF ANALYSIS	CARRY FORWARD?
Option 6: An 80-100 MW cold reserve unit.	No	Cold Reserve Cost Estimate	Yes, initially
Option 7: Convert CT1 (LM6000 PD) to 2x1 wet cooled combined cycle resource.	Yes		No
Option 8: Convert CT1 (LM6000 PD) to 2x1 dry cooled combined cycle resource.	Yes		No
Option 9: Convert CT2 (LM6000 PF) to 2x1 wet cooled combined cycle resource.	Yes		Yes
Option 10: Convert CT2 (LM6000 PF) to 2x1 dry cooled combined cycle resource.	Yes		Yes
Option 11: Convert 10 MW Ben French diesel unit to fire natural gas.	Yes		Yes
Option 12: A 10 MW battery – 4-hour lithium ion battery storage to replace diesels.	Yes		Yes
Option 13: A 1x1 7HA.02 combined cycle plant without duct-firing.	Yes		Yes
Option 14: A 3x1 LM6000 PF+ combined cycle plant without duct-firing.	Yes		Yes
Option 15: A 2x1 LM6000 PF+ combined cycle plant without duct-firing.	Yes		Yes
Option 16: A 2x1 LM6000 PF+ combined cycle plant without duct-firing at CPGS.	Yes		Yes
Option 17: A 1x1 LM6000 PF+ combined cycle plant with duct-firing.	Yes		No
Option 18: A 1x0 LMS100 simple cycle combustion turbine peaking unit.	Yes		Yes
Option 19: A 1x0 LM6000 PF+ simple cycle combustion turbine peaking unit.	Yes		Yes
Option 20: A 1x0 7EA simple cycle combustion turbine peaking unit.	Yes		No
Option 21: A 200 MW solar photovoltaic single axis tracking resource.	Yes		Yes
Option 22: A 100 MW solar photovoltaic single axis tracking resource.	Yes		Yes
Option 23: A 50 MW solar photovoltaic single axis tracking resource.	Yes		Yes
Option 24: A 200 MW wind resource.	Yes		Yes, 2 of 3 locations
Option 25: A 100 MW wind resource.	Yes		Yes, 2 of 3 locations

OPTION NUMBER AND DESCRIPTION	BUSBAR PERFORMED (Y/N)	OTHER TYPE OF ANALYSIS	CARRY FORWARD?
Option 26: A 50 MW wind resource.	Yes		Yes, 2 of 3 locations
Option 27: A 10 MW 4-hour lithium ion battery storage unit.	Yes		No
Option 28: A 30 MW 4-hour lithium ion battery storage unit.	Yes		Yes
Option 29: A 100 MW 4-hour lithium ion battery storage unit.	Yes		Yes
Option 30: A 200 MW 4-hour lithium ion battery storage unit.	Yes		Yes
Option 31: A 100 MW biofuels plant.	Yes		No
Option 32: A 40 MW geothermal plant.	Yes		No
Option 33: A 120 MW small scale modular reactor assumed to be available no sooner than 2030.	Yes		No
Option 34A-E: Cost to add 30-minute battery to each LM6000.	Yes		Yes, except 34C
Option 35: NS2 Retirement.	No	Retirement Cost Estimate	Yes

Appendix A. Busbar Cost Models

Note: All busbar models show the maximum modeled capacity factor, except for the BESS options which are all shown at one cycle per day.

Option 1: 100 MW (90%) Carbon Capture System Installed at Existing 100 MW Unit in Gillette				
25-Year Levelized Cost of Carbon Reduction				
Plant Input Data		Economic Input Data	Rate	Escalation
CO2 Capture EPC Capital Cost ($1000)	$ 286,000	First Year Fixed O&M Cost ($/kW-yr)	63.9	1.5%
Other Owner Costs, except Esc & IDC	$ 28,600	First Year Variable O&M ($/MWh)	7.97	1.5%
Total Capital Cost (with Esc & IDC)	$ 314,600	Fuel Rate ($/lb)	0.87	
Total Net Output, Avg Ambient Cond. (kW)	68,000	Construction Period (months)		
Capacity Factor	90.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	11,780	Levelized Fixed Charge Rate (25 yr)	13.7%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/lb)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	42,943	4,345	4,273	0.87	5,517	0	0	57,078	52,967	10.65	9.88
2022	42,943	4,410	4,337	0.95	6,019	0	0	57,709	49,697	10.76	9.27
2023	42,943	4,477	4,402	0.96	6,065	0	0	57,887	46,260	10.80	8.63
2024	42,943	4,544	4,468	0.99	6,254	0	0	58,209	43,168	10.86	8.05
2025	42,943	4,612	4,535	1.07	6,752	0	0	58,841	40,494	10.98	7.55
2026	42,943	4,681	4,603	1.04	6,586	0	0	58,813	37,560	10.97	7.01
2027	42,943	4,751	4,672	1.04	6,540	0	0	58,906	34,910	10.99	6.51
2028	42,943	4,822	4,742	1.05	6,638	0	0	59,145	32,528	11.03	6.07
2029	42,943	4,895	4,813	1.07	6,737	0	0	59,388	30,310	11.08	5.65
2030	42,943	4,968	4,885	1.11	6,990	0	0	59,787	28,316	11.15	5.28
2031	42,943	5,043	4,959	1.10	6,941	0	0	59,885	26,320	11.17	4.91
2032	42,943	5,118	5,033	1.12	7,045	0	0	60,140	24,528	11.22	4.58
2033	42,943	5,195	5,109	1.13	7,151	0	0	60,398	22,860	11.27	4.26
2034	42,943	5,273	5,185	1.17	7,419	0	0	60,820	21,362	11.34	3.98
2035	42,943	5,352	5,263	1.17	7,367	0	0	60,925	19,858	11.36	3.70
2036	42,943	5,433	5,342	1.18	7,477	0	0	61,195	18,509	11.41	3.45
2037	42,943	5,514	5,422	1.20	7,590	0	0	61,469	17,253	11.47	3.22
2038	42,943	5,597	5,503	1.25	7,874	0	0	61,917	16,128	11.55	3.01
2039	42,943	5,681	5,586	1.24	7,819	0	0	62,029	14,993	11.57	2.80
2040	42,943	5,766	5,670	1.26	7,936	0	0	62,315	13,978	11.62	2.61
2041	42,943	5,852	5,755	1.28	8,055	0	0	62,605	13,032	11.68	2.43
2042	42,943	5,940	5,841	1.32	8,357	0	0	63,082	12,185	11.77	2.27
2043	42,943	6,029	5,929	1.31	8,299	0	0	63,200	11,329	11.79	2.11
2044	42,943	6,120	6,018	1.33	8,423	0	0	63,504	10,564	11.85	1.97
2045	42,943	6,211	6,108	1.35	8,550	0	0	63,812	9,851	11.90	1.84
							Net Levelized Busbar Cost (c/kWh)				**11.11**
							Net Levelized Cost ($000s)				**59,552**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-1 Busbar Cost Model for Option 1 at a 90 Percent Capacity Factor

Option 2: New 120 MW Supercritical Coal Plant with Carbon Capture

25-Year Busbar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 2,658,110	First Year Fixed O&M Cost ($/kW-yr)	37.2	1.5%
Other Owner Costs, except Esc & IDC	$ 1,196,308	First Year Variable O&M ($/MWh)	6.37	1.5%
Total Capital Cost (with Esc & IDC)	$ 3,854,418	Fuel Rate ($/lb)	0.87	
Total Net Output, Avg Ambient Cond. (kW)	380,000	Construction Period (months)		
Capacity Factor	90.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	11,142	Levelized Fixed Charge Rate (25 yr)	13.7%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/lb)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	526,128	14,151	19,084	0.87	29,159	0	0	588,522	546,142	19.64	18.23
2022	526,128	14,363	19,370	0.95	31,815	0	0	591,677	509,530	19.75	17.01
2023	526,128	14,579	19,661	0.96	32,059	0	0	592,426	473,436	19.77	15.80
2024	526,128	14,798	19,956	0.99	33,056	0	0	593,938	440,464	19.82	14.70
2025	526,128	15,020	20,255	1.07	35,686	0	0	597,088	410,914	19.93	13.72
2026	526,128	15,245	20,559	1.04	34,810	0	0	596,742	381,102	19.92	12.72
2027	526,128	15,474	20,867	1.04	34,566	0	0	597,035	353,832	19.93	11.81
2028	526,128	15,706	21,180	1.05	35,085	0	0	598,099	328,937	19.96	10.98
2029	526,128	15,941	21,498	1.07	35,611	0	0	599,178	305,800	20.00	10.21
2030	526,128	16,180	21,820	1.11	36,946	0	0	601,075	284,677	20.06	9.50
2031	526,128	16,423	22,148	1.10	36,687	0	0	601,386	264,314	20.07	8.82
2032	526,128	16,669	22,480	1.12	37,238	0	0	602,515	245,741	20.11	8.20
2033	526,128	16,919	22,817	1.13	37,796	0	0	603,661	228,478	20.15	7.63
2034	526,128	17,173	23,159	1.17	39,213	0	0	605,674	212,732	20.22	7.10
2035	526,128	17,431	23,507	1.17	38,939	0	0	606,004	197,520	20.23	6.59
2036	526,128	17,692	23,859	1.18	39,523	0	0	607,202	183,659	20.27	6.13
2037	526,128	17,958	24,217	1.20	40,116	0	0	608,419	170,775	20.31	5.70
2038	526,128	18,227	24,581	1.25	41,620	0	0	610,555	159,033	20.38	5.31
2039	526,128	18,500	24,949	1.24	41,328	0	0	610,906	147,666	20.39	4.93
2040	526,128	18,778	25,324	1.26	41,948	0	0	612,178	137,317	20.43	4.58
2041	526,128	19,060	25,703	1.28	42,577	0	0	613,468	127,698	20.48	4.26
2042	526,128	19,346	26,089	1.32	44,174	0	0	615,736	118,940	20.55	3.97
2043	526,128	19,636	26,480	1.31	43,864	0	0	616,108	110,442	20.56	3.69
2044	526,128	19,930	26,877	1.33	44,522	0	0	617,458	102,713	20.61	3.43
2045	526,128	20,229	27,281	1.35	45,190	0	0	618,828	95,528	20.66	3.19
							Net Levelized Busbar Cost (c/kWh)				**20.02**
							Net Levelized Cost ($000s)				**599,909**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-2 Busbar Cost Model for Option 2 at a 90 Percent Capacity Factor

Option 3: Conversion of LM6000 CT to Burn 35% Hydrogen Blend

25-Year Busbar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 3,864	First Year Fixed O&M Cost ($/kW-yr)	43.0	1.5%
Other Owner Costs, except Esc & IDC	$ 840	First Year Variable O&M ($/MWh)	7.80	1.5%
Total Capital Cost (with Esc & IDC)	$ 4,704	Blended Fuel Rate ($/MMBTU)	10.97	1.5%
Total Net Output, Avg Ambient Cond. (kW)	42,000	Construction Period (months)		
Capacity Factor	35.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	9,400	Levelized Fixed Charge Rate (25 yr)	14.4%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/lb)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	678	1,806	1,004	10.97	13,279	0	0	16,767	15,560	13.02	12.08
2022	678	1,833	1,019	11.13	13,478	0	0	17,008	14,647	13.21	11.37
2023	678	1,861	1,035	11.30	13,680	0	0	17,253	13,788	13.40	10.71
2024	678	1,888	1,050	11.47	13,885	0	0	17,502	12,979	13.59	10.08
2025	678	1,917	1,066	11.64	14,094	0	0	17,754	12,218	13.79	9.49
2026	678	1,946	1,082	11.82	14,305	0	0	18,010	11,502	13.99	8.93
2027	678	1,975	1,098	12.00	14,520	0	0	18,270	10,828	14.19	8.41
2028	678	2,004	1,115	12.17	14,737	0	0	18,534	10,193	14.39	7.92
2029	678	2,034	1,131	12.36	14,958	0	0	18,802	9,596	14.60	7.45
2030	678	2,065	1,148	12.54	15,183	0	0	19,074	9,034	14.81	7.02
2031	678	2,096	1,166	12.73	15,410	0	0	19,350	8,504	15.03	6.60
2032	678	2,127	1,183	12.92	15,642	0	0	19,630	8,006	15.24	6.22
2033	678	2,159	1,201	13.12	15,876	0	0	19,914	7,537	15.46	5.85
2034	678	2,192	1,219	13.31	16,114	0	0	20,203	7,096	15.69	5.51
2035	678	2,225	1,237	13.51	16,356	0	0	20,496	6,680	15.92	5.19
2036	678	2,258	1,256	13.72	16,601	0	0	20,793	6,289	16.15	4.88
2037	678	2,292	1,275	13.92	16,850	0	0	21,095	5,921	16.38	4.60
2038	678	2,326	1,294	14.13	17,103	0	0	21,401	5,574	16.62	4.33
2039	678	2,361	1,313	14.34	17,360	0	0	21,712	5,248	16.86	4.08
2040	678	2,396	1,333	14.56	17,620	0	0	22,027	4,941	17.11	3.84
2041	0	2,432	1,353	14.77	17,884	0	0	21,670	4,511	16.83	3.50
2042	0	2,469	1,373	15.00	18,153	0	0	21,995	4,249	17.08	3.30
2043	0	2,506	1,394	15.22	18,425	0	0	22,325	4,002	17.34	3.11
2044	0	2,544	1,415	15.45	18,701	0	0	22,660	3,769	17.60	2.93
2045	0	2,582	1,436	15.68	18,982	0	0	22,999	3,550	17.86	2.76
								Net Levelized Busbar Cost (c/kWh)			**14.70**
								Net Levelized Cost ($000s)			**18,924**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-3 Busbar Cost Model for Option 3 at a 35 Percent Capacity Factor

Option 4: 80-100 MW Coal to Gas Conversion Unit

25-Year Busbar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 9,057	First Year Fixed O&M Cost ($/kW-yr)	41.9	1.5%
Other Owner Costs, except Esc & IDC	$ 788	First Year Variable O&M ($/MWh)	1.78	1.5%
Total Capital Cost (with Esc & IDC)	$ 9,845	Fuel Rate ($/lb)	4.08	1.5%
Total Net Output, Avg Ambient Cond. (kW)	79,000	Construction Period (months)		
Capacity Factor	90.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	12,744	Levelized Fixed Charge Rate (25 yr)	13.7%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/lb)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	1,344	3,307	1,109	4.08	32,385	0	0	38,144	35,397	6.12	5.68
2022	1,344	3,357	1,125	3.96	31,393	0	0	37,218	32,051	5.98	5.15
2023	1,344	3,407	1,142	4.33	34,356	0	0	40,249	32,165	6.46	5.16
2024	1,344	3,458	1,159	4.69	37,233	0	0	43,194	32,033	6.94	5.14
2025	1,344	3,510	1,177	4.96	39,356	0	0	45,387	31,235	7.29	5.01
2026	1,344	3,563	1,194	5.05	40,104	0	0	46,205	29,508	7.42	4.74
2027	1,344	3,616	1,212	5.06	40,163	0	0	46,335	27,461	7.44	4.41
2028	1,344	3,670	1,230	5.19	41,208	0	0	47,453	26,098	7.62	4.19
2029	1,344	3,725	1,249	5.25	41,638	0	0	47,956	24,475	7.70	3.93
2030	1,344	3,781	1,268	5.29	42,022	0	0	48,415	22,930	7.77	3.68
2031	1,344	3,838	1,287	5.47	43,404	0	0	49,873	21,919	8.01	3.52
2032	1,344	3,895	1,306	5.57	44,245	0	0	50,790	20,715	8.15	3.33
2033	1,344	3,954	1,326	5.67	44,979	0	0	51,602	19,531	8.28	3.14
2034	1,344	4,013	1,345	5.83	46,282	0	0	52,984	18,610	8.51	2.99
2035	1,344	4,073	1,366	6.14	48,742	0	0	55,525	18,098	8.91	2.91
2036	1,344	4,134	1,386	6.43	51,011	0	0	57,876	17,505	9.29	2.81
2037	1,344	4,196	1,407	6.74	53,525	0	0	60,472	16,974	9.71	2.73
2038	1,344	4,259	1,428	7.05	55,985	0	0	63,016	16,414	10.12	2.64
2039	1,344	4,323	1,449	7.27	57,725	0	0	64,841	15,673	10.41	2.52
2040	1,344	4,388	1,471	7.56	60,040	0	0	67,243	15,083	10.80	2.42
2041	1,344	4,454	1,493	7.82	62,097	0	0	69,388	14,444	11.14	2.32
2042	1,344	4,521	1,516	7.97	63,274	0	0	70,655	13,648	11.34	2.19
2043	1,344	4,589	1,538	8.18	64,935	0	0	72,405	12,979	11.63	2.08
2044	1,344	4,657	1,561	8.58	68,136	0	0	75,699	12,592	12.15	2.02
2045	1,344	4,727	1,585	9.00	71,457	0	0	79,113	12,213	12.70	1.96
							Net Levelized Busbar Cost (c/kWh)				**7.95**
							Net Levelized Cost ($000s)				**49,531**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-4 Busbar Cost Model for Option 4 at a 90 Percent Capacity Factor

Option 5: 80-100 MW Coal Plant Life Extension											
25-Year Busbar Cost Calculation											
Plant Input Data					Economic Input Data					Rate	Escalation
EPC Capital Cost ($1000)				$ 164,426	First Year Fixed O&M Cost ($/kW-yr)					45.5	1.5%
Other Owner Costs, except Esc & IDC				$ 18,270	First Year Variable O&M ($/MWh)					3.42	1.5%
Total Capital Cost (with Esc & IDC)				$ 182,696	Fuel Rate ($/lb)					0.87	1.5%
Total Net Output, Avg Ambient Cond. (kW)				80,200	Construction Period (months)						
Capacity Factor				90.0%	Present Worth Discount Rate					7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				13,204	Levelized Fixed Charge Rate (25 yr)					13.7%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/lb)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	24,938	3,647	2,162	0.87	7,293	0	0	38,041	35,302	6.02	5.58
2022	24,938	3,702	2,195	0.95	7,957	0	0	38,793	33,407	6.14	5.28
2023	24,938	3,758	2,228	0.96	8,018	0	0	38,942	31,120	6.16	4.92
2024	24,938	3,814	2,261	0.99	8,268	0	0	39,281	29,131	6.21	4.61
2025	24,938	3,871	2,295	1.07	8,925	0	0	40,030	27,548	6.33	4.36
2026	24,938	3,929	2,330	1.04	8,706	0	0	39,903	25,484	6.31	4.03
2027	24,938	3,988	2,365	1.04	8,645	0	0	39,936	23,668	6.32	3.74
2028	24,938	4,048	2,400	1.05	8,775	0	0	40,161	22,087	6.35	3.49
2029	24,938	4,109	2,436	1.07	8,907	0	0	40,390	20,613	6.39	3.26
2030	24,938	4,171	2,473	1.11	9,241	0	0	40,822	19,334	6.46	3.06
2031	24,938	4,233	2,510	1.10	9,176	0	0	40,857	17,957	6.46	2.84
2032	24,938	4,297	2,547	1.12	9,314	0	0	41,095	16,761	6.50	2.65
2033	24,938	4,361	2,585	1.13	9,453	0	0	41,338	15,646	6.54	2.47
2034	24,938	4,426	2,624	1.17	9,808	0	0	41,796	14,680	6.61	2.32
2035	24,938	4,493	2,664	1.17	9,739	0	0	41,833	13,635	6.62	2.16
2036	24,938	4,560	2,704	1.18	9,885	0	0	42,087	12,730	6.66	2.01
2037	24,938	4,629	2,744	1.20	10,033	0	0	42,344	11,885	6.70	1.88
2038	24,938	4,698	2,785	1.25	10,410	0	0	42,831	11,156	6.77	1.76
2039	24,938	4,769	2,827	1.24	10,337	0	0	42,870	10,362	6.78	1.64
2040	24,938	4,840	2,869	1.26	10,492	0	0	43,139	9,677	6.82	1.53
2041	24,938	4,913	2,913	1.28	10,649	0	0	43,412	9,037	6.87	1.43
2042	24,938	4,986	2,956	1.32	11,048	0	0	43,929	8,486	6.95	1.34
2043	24,938	5,061	3,001	1.31	10,971	0	0	43,971	7,882	6.95	1.25
2044	24,938	5,137	3,046	1.33	11,135	0	0	44,256	7,362	7.00	1.16
2045	24,938	5,214	3,091	1.35	11,302	0	0	44,546	6,877	7.05	1.09
						Net Levelized Busbar Cost (c/kWh)					**6.41**
						Net Levelized Cost ($000s)					**40,545**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-5 Busbar Cost Model for Option 5 at a 90 Percent Capacity Factor

Option 7: 102 MW NSC CT1 (LM6000 PD) Conversion to 2x1 Wet Cooled CC											
25-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 98,328		First Year Fixed O&M Cost ($/kW-yr)				40.0	1.5%
Other Owner Costs, except Esc & IDC				$ 24,582		First Year Variable O&M ($/MWh)				5.40	1.5%
Total Capital Cost (with Esc & IDC)				$ 122,910		Fuel Rat ($/MMBTU)				4.08	
Total Net Output, Avg Ambient Cond. (kW)				102,000		Construction Period (months)					
Capacity Factor				90.0%		Present Worth Discount Rate				7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				7,200		Levelized Fixed Charge Rate (25 yr)				13.7%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	16,777	4,080	4,343	4.08	23,623	0	0	48,823	45,307	6.07	5.63
2022	16,777	4,141	4,408	3.96	22,899	0	0	48,226	41,530	6.00	5.16
2023	16,777	4,203	4,474	4.33	25,061	0	0	50,515	40,369	6.28	5.02
2024	16,777	4,266	4,541	4.69	27,160	0	0	52,744	39,115	6.56	4.86
2025	16,777	4,330	4,609	4.96	28,709	0	0	54,425	37,455	6.77	4.66
2026	16,777	4,395	4,678	5.05	29,254	0	0	55,105	35,192	6.85	4.38
2027	16,777	4,461	4,748	5.06	29,297	0	0	55,284	32,764	6.87	4.07
2028	16,777	4,528	4,820	5.19	30,060	0	0	56,185	30,900	6.99	3.84
2029	16,777	4,596	4,892	5.25	30,373	0	0	56,639	28,906	7.04	3.59
2030	16,777	4,665	4,965	5.29	30,653	0	0	57,061	27,025	7.10	3.36
2031	16,777	4,735	5,040	5.47	31,662	0	0	58,214	25,585	7.24	3.18
2032	16,777	4,806	5,115	5.57	32,274	0	0	58,973	24,053	7.33	2.99
2033	16,777	4,878	5,192	5.67	32,810	0	0	59,657	22,580	7.42	2.81
2034	16,777	4,951	5,270	5.83	33,761	0	0	60,759	21,340	7.56	2.65
2035	16,777	5,026	5,349	6.14	35,555	0	0	62,707	20,439	7.80	2.54
2036	16,777	5,101	5,429	6.43	37,210	0	0	64,518	19,515	8.02	2.43
2037	16,777	5,177	5,511	6.74	39,044	0	0	66,509	18,668	8.27	2.32
2038	16,777	5,255	5,593	7.05	40,839	0	0	68,464	17,833	8.51	2.22
2039	16,777	5,334	5,677	7.27	42,108	0	0	69,896	16,895	8.69	2.10
2040	16,777	5,414	5,762	7.56	43,797	0	0	71,750	16,094	8.92	2.00
2041	16,777	5,495	5,849	7.82	45,297	0	0	73,418	15,283	9.13	1.90
2042	16,777	5,578	5,936	7.97	46,156	0	0	74,447	14,381	9.26	1.79
2043	16,777	5,661	6,026	8.18	47,367	0	0	75,831	13,593	9.43	1.69
2044	16,777	5,746	6,116	8.58	49,702	0	0	78,342	13,032	9.74	1.62
2045	16,777	5,832	6,208	9.00	52,125	0	0	80,942	12,495	10.07	1.55
							Net Levelized Busbar Cost (c/kWh)				**7.19**
							Net Levelized Cost ($000s)				**57,845**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-6 Busbar Cost Model for Option 7 at a 90 Percent Capacity Factor

Option 8: 101 MW – NSC CT1 (LM6000 PD) Convert to 2x1 Dry CC				
25-Year Busbar Cost Calculation				
Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 101,909	First Year Fixed O&M Cost ($/kW-yr)	41.0	1.5%
Other Owner Costs, except Esc & IDC	$ 25,452	First Year Variable O&M ($/MWh)	5.30	1.5%
Total Capital Cost (with Esc & IDC)	$ 127,361	Fuel Rat(($/MMBTU)	4.08	
Total Net Output, Avg Ambient Cond. (kW)	101,000	Construction Period (months)		
Capacity Factor	90.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	7,350	Levelized Fixed Charge Rate (25 yr)	13.7%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	17,385	4,141	4,220	4.08	23,879	0	0	49,625	46,051	6.23	5.78
2022	17,385	4,203	4,284	3.96	23,147	0	0	49,019	42,213	6.16	5.30
2023	17,385	4,266	4,348	4.33	25,332	0	0	51,331	41,021	6.45	5.15
2024	17,385	4,330	4,413	4.69	27,454	0	0	53,582	39,736	6.73	4.99
2025	17,385	4,395	4,479	4.96	29,020	0	0	55,279	38,043	6.94	4.78
2026	17,385	4,461	4,546	5.05	29,571	0	0	55,963	35,740	7.03	4.49
2027	17,385	4,528	4,615	5.06	29,615	0	0	56,142	33,272	7.05	4.18
2028	17,385	4,596	4,684	5.19	30,385	0	0	57,050	31,376	7.16	3.94
2029	17,385	4,665	4,754	5.25	30,702	0	0	57,506	29,349	7.22	3.69
2030	17,385	4,735	4,825	5.29	30,985	0	0	57,930	27,436	7.28	3.45
2031	17,385	4,806	4,898	5.47	32,004	0	0	59,093	25,972	7.42	3.26
2032	17,385	4,878	4,971	5.57	32,624	0	0	59,858	24,413	7.52	3.07
2033	17,385	4,951	5,046	5.67	33,165	0	0	60,547	22,916	7.60	2.88
2034	17,385	5,025	5,122	5.83	34,126	0	0	61,658	21,656	7.74	2.72
2035	17,385	5,101	5,198	6.14	35,940	0	0	63,624	20,738	7.99	2.60
2036	17,385	5,177	5,276	6.43	37,613	0	0	65,452	19,797	8.22	2.49
2037	17,385	5,255	5,356	6.74	39,467	0	0	67,462	18,936	8.47	2.38
2038	17,385	5,334	5,436	7.05	41,281	0	0	69,435	18,086	8.72	2.27
2039	17,385	5,414	5,517	7.27	42,564	0	0	70,880	17,133	8.90	2.15
2040	17,385	5,495	5,600	7.56	44,271	0	0	72,751	16,319	9.14	2.05
2041	17,385	5,577	5,684	7.82	45,788	0	0	74,434	15,494	9.35	1.95
2042	17,385	5,661	5,769	7.97	46,656	0	0	75,471	14,578	9.48	1.83
2043	17,385	5,746	5,856	8.18	47,880	0	0	76,866	13,779	9.65	1.73
2044	17,385	5,832	5,944	8.58	50,240	0	0	79,401	13,208	9.97	1.66
2045	17,385	5,920	6,033	9.00	52,689	0	0	82,026	12,662	10.30	1.59
							Net Levelized Busbar Cost (c/kWh)				**7.37**
							Net Levelized Cost ($000s)				**58,723**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-7 Busbar Cost Model for Option 8 at a 90 Percent Capacity Factor

Option 9: 97 MW – CPGS CT2 (LM6000 PF) Convert to 2x1 Wet CC				
25-Year Busbar Cost Calculation				
Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 98,261	First Year Fixed O&M Cost ($/kW-yr)	40.0	1.5%
Other Owner Costs, except Esc & IDC	$ 24,541	First Year Variable O&M ($/MWh)	5.40	1.5%
Total Capital Cost (with Esc & IDC)	$ 122,899	Fuel Rate ($/MMBTU)	3.21	
Total Net Output, Avg Ambient Cond. (kW)	97,000	Construction Period (months)		
Capacity Factor	90.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	7,150	Levelized Fixed Charge Rate (25 yr)	13.7%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cos ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	16,776	3,880	4,130	3.21	17,536	0	0	42,322	39,274	5.53	5.14
2022	16,776	3,938	4,192	3.07	16,770	0	0	41,676	35,889	5.45	4.69
2023	16,776	3,997	4,254	3.43	18,747	0	0	43,774	34,982	5.72	4.57
2024	16,776	4,057	4,318	3.78	20,666	0	0	45,817	33,978	5.99	4.44
2025	16,776	4,118	4,383	4.04	22,067	0	0	47,344	32,582	6.19	4.26
2026	16,776	4,180	4,449	4.12	22,526	0	0	47,931	30,610	6.27	4.00
2027	16,776	4,243	4,516	4.11	22,468	0	0	48,002	28,448	6.28	3.72
2028	16,776	4,306	4,583	4.23	23,124	0	0	48,789	26,832	6.38	3.51
2029	16,776	4,371	4,652	4.27	23,343	0	0	49,142	25,080	6.43	3.28
2030	16,776	4,436	4,722	4.31	23,582	0	0	49,516	23,451	6.47	3.07
2031	16,776	4,503	4,793	4.47	24,467	0	0	50,538	22,212	6.61	2.90
2032	16,776	4,570	4,865	4.56	24,948	0	0	51,158	20,865	6.69	2.73
2033	16,776	4,639	4,937	4.64	25,398	0	0	51,751	19,587	6.77	2.56
2034	16,776	4,709	5,012	4.79	26,167	0	0	52,663	18,497	6.89	2.42
2035	16,776	4,779	5,087	5.09	27,810	0	0	54,452	17,748	7.12	2.32
2036	16,776	4,851	5,163	5.36	29,305	0	0	56,094	16,967	7.34	2.22
2037	16,776	4,924	5,240	5.66	30,938	0	0	57,878	16,246	7.57	2.12
2038	16,776	4,998	5,319	5.95	32,536	0	0	59,628	15,532	7.80	2.03
2039	16,776	5,072	5,399	6.15	33,604	0	0	60,851	14,709	7.96	1.92
2040	16,776	5,149	5,480	6.42	35,123	0	0	62,528	14,026	8.18	1.83
2041	16,776	5,226	5,562	6.67	36,467	0	0	64,031	13,328	8.37	1.74
2042	16,776	5,304	5,645	6.80	37,208	0	0	64,933	12,543	8.49	1.64
2043	16,776	5,384	5,730	6.99	38,224	0	0	66,113	11,851	8.65	1.55
2044	16,776	5,465	5,816	7.37	40,318	0	0	68,374	11,374	8.94	1.49
2045	16,776	5,546	5,903	7.77	42,473	0	0	70,699	10,914	9.24	1.43
								Net Levelized Busbar Cost (c/kWh)			**6.57**
								Net Levelized Cost ($000s)			**50,244**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-8 Busbar Cost Model for Option 9 at a 90 Percent Capacity Factor

Option 10: 96 MW – CPGS CT2 (LM6000 PF) Convert to 2x1 Dry CC

25-Year Busbar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 101,952	First Year Fixed O&M Cost ($/kW-yr)	41.0	1.5%
Other Owner Costs, except Esc & IDC	$ 25,440	First Year Variable O&M ($/MWh)	5.30	1.5%
Total Capital Cost (with Esc & IDC)	$ 127,392	Fuel Rate ($/MMBTU)	3.21	
Total Net Output, Avg Ambient Cond. (kW)	96,000	Construction Period (months)		
Capacity Factor	90.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	7,250	Levelized Fixed Charge Rate (25 yr)	13.7%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	17,389	3,936	4,011	3.21	17,598	0	0	42,935	39,843	5.67	5.26
2022	17,389	3,995	4,072	3.07	16,829	0	0	42,285	36,414	5.59	4.81
2023	17,389	4,055	4,133	3.43	18,813	0	0	44,390	35,474	5.86	4.69
2024	17,389	4,116	4,195	3.78	20,739	0	0	46,439	34,439	6.14	4.55
2025	17,389	4,178	4,258	4.04	22,145	0	0	47,969	33,012	6.34	4.36
2026	17,389	4,240	4,321	4.12	22,606	0	0	48,557	31,010	6.42	4.10
2027	17,389	4,304	4,386	4.11	22,547	0	0	48,626	28,818	6.42	3.81
2028	17,389	4,368	4,452	4.23	23,205	0	0	49,415	27,177	6.53	3.59
2029	17,389	4,434	4,519	4.27	23,426	0	0	49,767	25,399	6.58	3.36
2030	17,389	4,500	4,587	4.31	23,665	0	0	50,141	23,747	6.62	3.14
2031	17,389	4,568	4,655	4.47	24,553	0	0	51,166	22,488	6.76	2.97
2032	17,389	4,636	4,725	4.56	25,036	0	0	51,786	21,122	6.84	2.79
2033	17,389	4,706	4,796	4.64	25,488	0	0	52,379	19,825	6.92	2.62
2034	17,389	4,777	4,868	4.79	26,260	0	0	53,293	18,718	7.04	2.47
2035	17,389	4,848	4,941	5.09	27,908	0	0	55,086	17,955	7.28	2.37
2036	17,389	4,921	5,015	5.36	29,408	0	0	56,733	17,160	7.50	2.27
2037	17,389	4,995	5,090	5.66	31,047	0	0	58,521	16,426	7.73	2.17
2038	17,389	5,070	5,167	5.95	32,651	0	0	60,276	15,700	7.96	2.07
2039	17,389	5,146	5,244	6.15	33,723	0	0	61,502	14,866	8.13	1.96
2040	17,389	5,223	5,323	6.42	35,247	0	0	63,182	14,172	8.35	1.87
2041	17,389	5,301	5,403	6.67	36,596	0	0	64,689	13,465	8.55	1.78
2042	17,389	5,381	5,484	6.80	37,339	0	0	65,593	12,670	8.67	1.67
2043	17,389	5,461	5,566	6.99	38,359	0	0	66,775	11,970	8.82	1.58
2044	17,389	5,543	5,650	7.37	40,460	0	0	69,042	11,485	9.12	1.52
2045	17,389	5,627	5,734	7.77	42,623	0	0	71,373	11,018	9.43	1.46
							Net Levelized Busbar Cost (c/kWh)				**6.72**
							Net Levelized Cost ($000s)				**50,873**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-9 Busbar Cost Model for Option 10 at a 90 Percent Capacity Factor

Option 11: Convert 10 MW Diesel to Natural Gas (Rapid City)											
25-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 2,625		First Year Fixed O&M Cost ($/kW-yr)				0.0	1.5%
Other Owner Costs, except Esc & IDC				$ 578		First Year Variable O&M ($/MWh)				0.00	1.5%
Total Capital Cost (with Esc & IDC)				$ 3,203		Fuel Rate ($/MMBTU)				4.34	
Total Net Output, Avg Ambient Cond. (kW)				7,500		Construction Period (months)					
Capacity Factor				35.0%		Present Worth Discount Rate				7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				11,900		Levelized Fixed Charge Rate (25 yr)				14.4%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	461	0	0	4.34	1,189	0	0	1,650	1,532	7.18	6.66
2022	461	0	0	4.21	1,152	0	0	1,614	1,390	7.02	6.04
2023	461	0	0	4.61	1,262	0	0	1,723	1,377	7.49	5.99
2024	461	0	0	5.00	1,367	0	0	1,828	1,356	7.95	5.90
2025	461	0	0	5.28	1,445	0	0	1,907	1,312	8.29	5.71
2026	461	0	0	5.38	1,472	0	0	1,934	1,235	8.41	5.37
2027	461	0	0	5.39	1,475	0	0	1,936	1,148	8.42	4.99
2028	461	0	0	5.53	1,513	0	0	1,974	1,086	8.59	4.72
2029	461	0	0	5.59	1,529	0	0	1,990	1,016	8.66	4.42
2030	461	0	0	5.64	1,543	0	0	2,004	949	8.72	4.13
2031	461	0	0	5.82	1,594	0	0	2,055	903	8.94	3.93
2032	461	0	0	5.94	1,625	0	0	2,086	851	9.07	3.70
2033	461	0	0	6.04	1,652	0	0	2,113	800	9.19	3.48
2034	461	0	0	6.21	1,699	0	0	2,161	759	9.40	3.30
2035	461	0	0	6.54	1,790	0	0	2,251	734	9.79	3.19
2036	461	0	0	6.84	1,873	0	0	2,334	706	10.15	3.07
2037	461	0	0	7.18	1,966	0	0	2,427	681	10.55	2.96
2038	461	0	0	7.51	2,056	0	0	2,517	656	10.95	2.85
2039	461	0	0	7.74	2,119	0	0	2,581	624	11.22	2.71
2040	461	0	0	8.06	2,204	0	0	2,666	598	11.59	2.60
2041	0	0	0	8.33	2,280	0	0	2,280	475	9.92	2.06
2042	0	0	0	8.49	2,323	0	0	2,323	449	10.10	1.95
2043	0	0	0	8.71	2,384	0	0	2,384	427	10.37	1.86
2044	0	0	0	9.14	2,502	0	0	2,502	416	10.88	1.81
2045	0	0	0	9.59	2,624	0	0	2,624	405	11.41	1.76
							Net Levelized Busbar Cost (c/kWh)				**8.73**
							Net Levelized Cost ($000s)				**2,008**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-10 Busbar Cost Model for Option 11 at a 35 Percent Capacity Factor

Option 12: 10 MW 4-hour BESS as Diesel Replacement

20-Year Busbar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 19,102	First Year Fixed O&M Cost ($/kWh-yr)	7.5	1.5%
Other Owner Costs, except Esc & IDC	$ 2,122	1st Yr. Var. O&M Charging Cost, $/kWh	0.02	1.5%
Total Capital Cost (with Esc & IDC)	$ 21,225	Fuel Rate ($/MMBTU)	0.00	
kW of Output	10,000	Number of Cycles per Day	1	
Hours of Full Output per Cycle	4	Present Worth Discount Rate	7.8%	
kWh Purchased/Cycle	44,444	Levelized Fixed Charge Rate (20 yr)	13.9%	

Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	2,955	0.202	300	269	0.00	0	0	3,523	3,270	24.13	22.39
2022	2,955	0.202	305	301	0.00	0	0	3,560	3,066	24.38	21.00
2023	2,955	0.202	309	340	0.00	0	0	3,603	2,879	24.68	19.72
2024	2,955	0.202	314	343	0.00	0	0	3,611	2,678	24.74	18.34
2025	2,955	0.202	318	340	0.00	0	0	3,613	2,487	24.75	17.03
2026	2,955	0.202	323	352	0.00	0	0	3,630	2,318	24.86	15.88
2027	2,955	0.202	328	363	0.00	0	0	3,645	2,160	24.97	14.80
2028	2,955	0.202	333	386	0.00	0	0	3,674	2,021	25.16	13.84
2029	2,955	0.202	338	384	0.00	0	0	3,676	1,876	25.18	12.85
2030	2,955	0.202	343	381	0.00	0	0	3,678	1,742	25.19	11.93
2031	2,955	0.202	348	396	0.00	0	0	3,699	1,626	25.34	11.14
2032	2,955	0.202	353	417	0.00	0	0	3,725	1,519	25.51	10.41
2033	2,955	0.202	359	432	0.00	0	0	3,745	1,417	25.65	9.71
2034	2,955	0.202	364	435	0.00	0	0	3,753	1,318	25.71	9.03
2035	2,955	0.202	370	435	0.00	0	0	3,759	1,225	25.75	8.39
2036	2,955	0.202	375	436	0.00	0	0	3,765	1,139	25.79	7.80
2037	2,955	0.202	381	461	0.00	0	0	3,796	1,066	26.00	7.30
2038	2,955	0.202	386	471	0.00	0	0	3,812	993	26.11	6.80
2039	2,955	0.202	392	485	0.00	0	0	3,832	926	26.25	6.34
2040	2,955	0.202	398	485	0.00	0	0	3,837	861	26.28	5.90
							Net Levelized Busbar Cost (c/kWh)				**25.07**
							Net Levelized Cost ($000s)				**3,660**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-11 Busbar Cost Model for Option 12 at One Cycle Per Day

Option 13W: 444 MW - 1x1 7HA.02 CC w/o DF at CPGS											
25-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 351,204		First Year Fixed O&M Cost ($/kW-yr)				10.0	1.5%
Other Owner Costs, except Esc & IDC				$ 87,912		First Year Variable O&M ($/MWh)				3.50	1.5%
Total Capital Cost (with Esc & IDC)				$ 439,116		Fuel Rat(($/MMBTU)				3.21	
Total Net Output, Avg Ambient Cond. (kW)				444,000		Construction Period (months)					
Capacity Factor				90.0%		Present Worth Discount Rate				7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				6,300		Levelized Fixed Charge Rate (25 yr)				13.7%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	59,939	4,440	12,252	3.21	70,727	0	0	147,358	136,747	4.21	3.91
2022	59,939	4,507	12,436	3.07	67,637	0	0	144,518	124,453	4.13	3.56
2023	59,939	4,574	12,622	3.43	75,609	0	0	152,744	122,065	4.36	3.49
2024	59,939	4,643	12,811	3.78	83,350	0	0	160,743	119,207	4.59	3.41
2025	59,939	4,712	13,004	4.04	89,000	0	0	166,655	114,691	4.76	3.28
2026	59,939	4,783	13,199	4.12	90,853	0	0	168,774	107,785	4.82	3.08
2027	59,939	4,855	13,397	4.11	90,617	0	0	168,807	100,043	4.82	2.86
2028	59,939	4,928	13,598	4.23	93,262	0	0	171,726	94,444	4.91	2.70
2029	59,939	5,002	13,801	4.27	94,146	0	0	172,889	88,237	4.94	2.52
2030	59,939	5,077	14,009	4.31	95,109	0	0	174,133	82,472	4.97	2.36
2031	59,939	5,153	14,219	4.47	98,679	0	0	177,990	78,228	5.08	2.23
2032	59,939	5,230	14,432	4.56	100,618	0	0	180,220	73,504	5.15	2.10
2033	59,939	5,309	14,648	4.64	102,436	0	0	182,332	69,011	5.21	1.97
2034	59,939	5,388	14,868	4.79	105,536	0	0	185,732	65,235	5.31	1.86
2035	59,939	5,469	15,091	5.09	112,162	0	0	192,661	62,796	5.50	1.79
2036	59,939	5,551	15,318	5.36	118,191	0	0	198,999	60,191	5.68	1.72
2037	59,939	5,634	15,547	5.66	124,778	0	0	205,899	57,793	5.88	1.65
2038	59,939	5,719	15,780	5.95	131,223	0	0	212,662	55,393	6.08	1.58
2039	59,939	5,805	16,017	6.15	135,531	0	0	217,293	52,523	6.21	1.50
2040	59,939	5,892	16,257	6.42	141,658	0	0	223,747	50,189	6.39	1.43
2041	59,939	5,980	16,501	6.67	147,078	0	0	229,498	47,772	6.56	1.36
2042	59,939	6,070	16,749	6.80	150,065	0	0	232,823	44,974	6.65	1.28
2043	59,939	6,161	17,000	6.99	154,162	0	0	237,262	42,531	6.78	1.21
2044	59,939	6,253	17,255	7.37	162,608	0	0	246,055	40,931	7.03	1.17
2045	59,939	6,347	17,514	7.77	171,300	0	0	255,101	39,380	7.29	1.12
						Net Levelized Busbar Cost (c/kWh)					**5.06**
						Net Levelized Cost ($000s)					**177,163**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-12 Busbar Cost Model for Option 13W at a 90 Percent Capacity Factor

Option 13SD: 444 MW - 1x1 7HA.02 CC w/o DF - Rapid City

25-Year Busbar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 351,204	First Year Fixed O&M Cost ($/kW-yr)	10.0	1.5%
Other Owner Costs, except Esc & IDC	$ 87,912	First Year Variable O&M ($/MWh)	3.50	1.5%
Total Capital Cost (with Esc & IDC)	$ 439,116	Fuel Rate ($/MMBTU)	4.34	
Total Net Output, Avg Ambient Cond. (kW)	444,000	Construction Period (months)		
Capacity Factor	90.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	6,300	Levelized Fixed Charge Rate (25 yr)	13.7%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	59,939	4,440	12,252	4.34	95,814	0	0	172,445	160,027	4.93	4.57
2022	59,939	4,507	12,436	4.21	92,877	0	0	169,758	146,189	4.85	4.18
2023	59,939	4,574	12,622	4.61	101,673	0	0	178,809	142,895	5.11	4.08
2024	59,939	4,643	12,811	5.00	110,161	0	0	187,554	139,090	5.36	3.97
2025	59,939	4,712	13,004	5.28	116,480	0	0	194,135	133,603	5.55	3.82
2026	59,939	4,783	13,199	5.38	118,663	0	0	196,584	125,546	5.62	3.59
2027	59,939	4,855	13,397	5.39	118,861	0	0	197,052	116,782	5.63	3.34
2028	59,939	4,928	13,598	5.53	121,909	0	0	200,374	110,200	5.72	3.15
2029	59,939	5,002	13,801	5.59	123,220	0	0	201,963	103,075	5.77	2.94
2030	59,939	5,077	14,009	5.64	124,345	0	0	203,370	96,319	5.81	2.75
2031	59,939	5,153	14,219	5.82	128,424	0	0	207,735	91,301	5.93	2.61
2032	59,939	5,230	14,432	5.94	130,937	0	0	210,539	85,870	6.01	2.45
2033	59,939	5,309	14,648	6.04	133,112	0	0	213,008	80,621	6.09	2.30
2034	59,939	5,388	14,868	6.21	136,943	0	0	217,139	76,266	6.20	2.18
2035	59,939	5,469	15,091	6.54	144,239	0	0	224,738	73,251	6.42	2.09
2036	59,939	5,551	15,318	6.84	150,945	0	0	231,753	70,098	6.62	2.00
2037	59,939	5,634	15,547	7.18	158,407	0	0	239,528	67,232	6.84	1.92
2038	59,939	5,719	15,780	7.51	165,672	0	0	247,111	64,366	7.06	1.84
2039	59,939	5,805	16,017	7.74	170,797	0	0	252,558	61,047	7.21	1.74
2040	59,939	5,892	16,257	8.06	177,653	0	0	259,741	58,262	7.42	1.66
2041	59,939	5,980	16,501	8.33	183,776	0	0	266,196	55,411	7.60	1.58
2042	59,939	6,070	16,749	8.49	187,226	0	0	269,984	52,152	7.71	1.49
2043	59,939	6,161	17,000	8.71	192,156	0	0	275,256	49,341	7.86	1.41
2044	59,939	6,253	17,255	9.14	201,616	0	0	285,064	47,420	8.14	1.35
2045	59,939	6,347	17,514	9.59	211,437	0	0	295,238	45,576	8.43	1.30
								Net Levelized Busbar Cost (c/kWh)			**5.90**
								Net Levelized Cost ($000s)			**206,651**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-13 Busbar Cost Model for Option 13SD at a 90 Percent Capacity Factor

Option 14W: 167 MW - 3x1 LM6000 PF + CC w/o DF at CPGS											
25-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 230,460		First Year Fixed O&M Cost ($/kW-yr)				28.0	1.5%
Other Owner Costs, except Esc & IDC				$ 57,615		First Year Variable O&M ($/MWh)				4.20	1.5%
Total Capital Cost (with Esc & IDC)				$ 288,242		Fuel Rate ($/MMBTU)				3.21	
Total Net Output, Avg Ambient Cond. (kW)				167,000		Construction Period (months)					
Capacity Factor				90.0%		Present Worth Discount Rate				7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				7,050		Levelized Fixed Charge Rate (25 yr)				13.7%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	39,345	4,676	5,530	3.21	29,769	0	0	79,320	73,608	6.02	5.59
2022	39,345	4,746	5,613	3.07	28,468	0	0	78,172	67,319	5.94	5.11
2023	39,345	4,817	5,697	3.43	31,824	0	0	81,683	65,277	6.20	4.96
2024	39,345	4,890	5,782	3.78	35,082	0	0	85,099	63,110	6.46	4.79
2025	39,345	4,963	5,869	4.04	37,460	0	0	87,637	60,312	6.66	4.58
2026	39,345	5,037	5,957	4.12	38,240	0	0	88,580	56,570	6.73	4.30
2027	39,345	5,113	6,047	4.11	38,141	0	0	88,645	52,535	6.73	3.99
2028	39,345	5,190	6,137	4.23	39,254	0	0	89,926	49,457	6.83	3.76
2029	39,345	5,267	6,229	4.27	39,627	0	0	90,468	46,172	6.87	3.51
2030	39,345	5,346	6,323	4.31	40,032	0	0	91,046	43,121	6.92	3.28
2031	39,345	5,427	6,418	4.47	41,534	0	0	92,724	40,753	7.04	3.10
2032	39,345	5,508	6,514	4.56	42,351	0	0	93,718	38,223	7.12	2.90
2033	39,345	5,591	6,612	4.64	43,116	0	0	94,663	35,829	7.19	2.72
2034	39,345	5,675	6,711	4.79	44,421	0	0	96,151	33,771	7.30	2.56
2035	39,345	5,760	6,811	5.09	47,209	0	0	99,125	32,309	7.53	2.45
2036	39,345	5,846	6,914	5.36	49,747	0	0	101,852	30,807	7.74	2.34
2037	39,345	5,934	7,017	5.66	52,520	0	0	104,816	29,420	7.96	2.23
2038	39,345	6,023	7,123	5.95	55,232	0	0	107,722	28,059	8.18	2.13
2039	39,345	6,113	7,229	6.15	57,046	0	0	109,733	26,524	8.33	2.01
2040	39,345	6,205	7,338	6.42	59,624	0	0	112,512	25,238	8.55	1.92
2041	39,345	6,298	7,448	6.67	61,905	0	0	114,996	23,937	8.73	1.82
2042	39,345	6,392	7,560	6.80	63,163	0	0	116,460	22,496	8.85	1.71
2043	39,345	6,488	7,673	6.99	64,887	0	0	118,394	21,223	8.99	1.61
2044	39,345	6,586	7,788	7.37	68,442	0	0	122,161	20,321	9.28	1.54
2045	39,345	6,684	7,905	7.77	72,101	0	0	126,035	19,456	9.57	1.48
							Net Levelized Busbar Cost (c/kWh)				**7.01**
							Net Levelized Cost ($000s)				**92,302**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-14 Busbar Cost Model for Option 14W at a 90 Percent Capacity Factor

Option 14SD: 167 MW - 3x1 LM6000 PF+ CC w/o DF - Rapid City				
25-Year Busbar Cost Calculation				
Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 230,460	First Year Fixed O&M Cost ($/kW-yr)	28.0	1.5%
Other Owner Costs, except Esc & IDC	$ 57,615	First Year Variable O&M ($/MWh)	4.20	1.5%
Total Capital Cost (with Esc & IDC)	$ 288,242	Fuel Rate ($/MMBTU)	4.34	
Total Net Output, Avg Ambient Cond. (kW)	167,000	Construction Period (months)		
Capacity Factor	90.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	7,050	Levelized Fixed Charge Rate (25 yr)	13.7%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	39,345	4,676	5,530	4.34	40,328	0	0	89,879	83,407	6.83	6.33
2022	39,345	4,746	5,613	4.21	39,092	0	0	88,796	76,468	6.74	5.81
2023	39,345	4,817	5,697	4.61	42,795	0	0	92,654	74,044	7.04	5.62
2024	39,345	4,890	5,782	5.00	46,367	0	0	96,384	71,478	7.32	5.43
2025	39,345	4,963	5,869	5.28	49,027	0	0	99,204	68,272	7.53	5.19
2026	39,345	5,037	5,957	5.38	49,946	0	0	100,285	64,046	7.62	4.86
2027	39,345	5,113	6,047	5.39	50,029	0	0	100,534	59,581	7.64	4.53
2028	39,345	5,190	6,137	5.53	51,312	0	0	101,984	56,088	7.75	4.26
2029	39,345	5,267	6,229	5.59	51,864	0	0	102,706	52,417	7.80	3.98
2030	39,345	5,346	6,323	5.64	52,337	0	0	103,352	48,949	7.85	3.72
2031	39,345	5,427	6,418	5.82	54,054	0	0	105,243	46,255	7.99	3.51
2032	39,345	5,508	6,514	5.94	55,112	0	0	106,479	43,428	8.09	3.30
2033	39,345	5,591	6,612	6.04	56,027	0	0	107,575	40,716	8.17	3.09
2034	39,345	5,675	6,711	6.21	57,640	0	0	109,370	38,414	8.31	2.92
2035	39,345	5,760	6,811	6.54	60,711	0	0	112,627	36,709	8.55	2.79
2036	39,345	5,846	6,914	6.84	63,533	0	0	115,638	34,977	8.78	2.66
2037	39,345	5,934	7,017	7.18	66,674	0	0	118,970	33,393	9.04	2.54
2038	39,345	6,023	7,123	7.51	69,732	0	0	122,222	31,836	9.28	2.42
2039	39,345	6,113	7,229	7.74	71,889	0	0	124,576	30,112	9.46	2.29
2040	39,345	6,205	7,338	8.06	74,774	0	0	127,662	28,636	9.70	2.17
2041	39,345	6,298	7,448	8.33	77,352	0	0	130,443	27,153	9.91	2.06
2042	39,345	6,392	7,560	8.49	78,804	0	0	132,101	25,518	10.03	1.94
2043	39,345	6,488	7,673	8.71	80,879	0	0	134,385	24,089	10.21	1.83
2044	39,345	6,586	7,788	9.14	84,861	0	0	138,579	23,052	10.53	1.75
2045	39,345	6,684	7,905	9.59	88,995	0	0	142,929	22,064	10.86	1.68
							Net Levelized Busbar Cost (c/kWh)				**7.95**
							Net Levelized Cost ($000s)				**104,714**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-15 Busbar Cost Model for Option 14SD at a 90 Percent Capacity Factor

Option 15W: 111 MW - 2x1 LM6000 PF+ CC w/o DF at CPGS

25-Year Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 161,505	First Year Fixed O&M Cost ($/kW-yr)	37.0	1.5%
Other Owner Costs, except Esc & IDC	$ 40,404	First Year Variable O&M ($/MWh)	5.20	1.5%
Total Capital Cost (with Esc & IDC)	$ 201,798	Fuel Rate ($/MMBTU)	3.21	
Total Net Output, Avg Ambient Cond. (kW)	111,000	Construction Period (months)		
Capacity Factor	90.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	7,050	Levelized Fixed Charge Rate (25 yr)	13.7%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	27,545	4,107	4,551	3.21	19,787	0	0	55,990	51,958	6.40	5.94
2022	27,545	4,169	4,619	3.07	18,922	0	0	55,255	47,584	6.31	5.44
2023	27,545	4,231	4,688	3.43	21,152	0	0	57,617	46,045	6.58	5.26
2024	27,545	4,295	4,759	3.78	23,318	0	0	59,917	44,434	6.85	5.08
2025	27,545	4,359	4,830	4.04	24,899	0	0	61,633	42,416	7.04	4.85
2026	27,545	4,424	4,902	4.12	25,417	0	0	62,289	39,780	7.12	4.55
2027	27,545	4,491	4,976	4.11	25,351	0	0	62,363	36,959	7.13	4.22
2028	27,545	4,558	5,051	4.23	26,091	0	0	63,245	34,783	7.23	3.97
2029	27,545	4,627	5,126	4.27	26,339	0	0	63,637	32,478	7.27	3.71
2030	27,545	4,696	5,203	4.31	26,608	0	0	64,052	30,336	7.32	3.47
2031	27,545	4,766	5,281	4.47	27,607	0	0	65,200	28,656	7.45	3.27
2032	27,545	4,838	5,360	4.56	28,149	0	0	65,893	26,875	7.53	3.07
2033	27,545	4,910	5,441	4.64	28,658	0	0	66,554	25,190	7.61	2.88
2034	27,545	4,984	5,522	4.79	29,525	0	0	67,577	23,735	7.72	2.71
2035	27,545	5,059	5,605	5.09	31,379	0	0	69,588	22,681	7.95	2.59
2036	27,545	5,135	5,689	5.36	33,065	0	0	71,435	21,607	8.16	2.47
2037	27,545	5,212	5,775	5.66	34,908	0	0	73,440	20,614	8.39	2.36
2038	27,545	5,290	5,861	5.95	36,711	0	0	75,408	19,642	8.62	2.24
2039	27,545	5,369	5,949	6.15	37,917	0	0	76,780	18,559	8.77	2.12
2040	27,545	5,450	6,038	6.42	39,631	0	0	78,664	17,645	8.99	2.02
2041	27,545	5,532	6,129	6.67	41,147	0	0	80,353	16,726	9.18	1.91
2042	27,545	5,615	6,221	6.80	41,983	0	0	81,363	15,717	9.30	1.80
2043	27,545	5,699	6,314	6.99	43,129	0	0	82,687	14,822	9.45	1.69
2044	27,545	5,784	6,409	7.37	45,491	0	0	85,230	14,178	9.74	1.62
2045	27,545	5,871	6,505	7.77	47,923	0	0	87,845	13,561	10.04	1.55
							Net Levelized Busbar Cost (c/kWh)				**7.41**
							Net Levelized Cost ($000s)				**64,877**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-16 Busbar Cost Model for Option 15W at a 90 Percent Capacity Factor

Option 15SD: 111 MW - 2x1 LM6000 PF+ CC w/o DF - Rapid City											
25-Year Busbar Cost Calculation											
Plant Input Data					Economic Input Data					Rate	Escalation
EPC Capital Cost ($1000)				$ 161,505	First Year Fixed O&M Cost ($/kW-yr)					37.0	1.5%
Other Owner Costs, except Esc & IDC				$ 40,404	First Year Variable O&M ($/MWh)					5.20	1.5%
Total Capital Cost (with Esc & IDC)				$ 201,798	Fuel Rate ($/MMBTU)					4.34	
Total Net Output, Avg Ambient Cond. (kW)				111,000	Construction Period (months)						
Capacity Factor				90.0%	Present Worth Discount Rate					7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				7,050	Levelized Fixed Charge Rate (25 yr)					13.7%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	27,545	4,107	4,551	4.34	26,805	0	0	63,008	58,471	7.20	6.68
2022	27,545	4,169	4,619	4.21	25,983	0	0	62,316	53,664	7.12	6.13
2023	27,545	4,231	4,688	4.61	28,444	0	0	64,909	51,872	7.42	5.93
2024	27,545	4,295	4,759	5.00	30,819	0	0	67,417	49,997	7.70	5.71
2025	27,545	4,359	4,830	5.28	32,587	0	0	69,321	47,706	7.92	5.45
2026	27,545	4,424	4,902	5.38	33,197	0	0	70,070	44,749	8.01	5.11
2027	27,545	4,491	4,976	5.39	33,253	0	0	70,265	41,642	8.03	4.76
2028	27,545	4,558	5,051	5.53	34,106	0	0	71,260	39,191	8.14	4.48
2029	27,545	4,627	5,126	5.59	34,472	0	0	71,771	36,629	8.20	4.19
2030	27,545	4,696	5,203	5.64	34,787	0	0	72,232	34,210	8.25	3.91
2031	27,545	4,766	5,281	5.82	35,928	0	0	73,521	32,313	8.40	3.69
2032	27,545	4,838	5,360	5.94	36,631	0	0	74,375	30,334	8.50	3.47
2033	27,545	4,910	5,441	6.04	37,240	0	0	75,136	28,438	8.59	3.25
2034	27,545	4,984	5,522	6.21	38,311	0	0	76,363	26,821	8.73	3.06
2035	27,545	5,059	5,605	6.54	40,353	0	0	78,562	25,606	8.98	2.93
2036	27,545	5,135	5,689	6.84	42,229	0	0	80,598	24,378	9.21	2.79
2037	27,545	5,212	5,775	7.18	44,316	0	0	82,848	23,254	9.47	2.66
2038	27,545	5,290	5,861	7.51	46,349	0	0	85,045	22,152	9.72	2.53
2039	27,545	5,369	5,949	7.74	47,782	0	0	86,646	20,944	9.90	2.39
2040	27,545	5,450	6,038	8.06	49,700	0	0	88,734	19,904	10.14	2.27
2041	27,545	5,532	6,129	8.33	51,413	0	0	90,619	18,863	10.36	2.16
2042	27,545	5,615	6,221	8.49	52,379	0	0	91,760	17,725	10.49	2.03
2043	27,545	5,699	6,314	8.71	53,758	0	0	93,316	16,728	10.66	1.91
2044	27,545	5,784	6,409	9.14	56,404	0	0	96,143	15,993	10.99	1.83
2045	27,545	5,871	6,505	9.59	59,152	0	0	99,074	15,294	11.32	1.75
							Net Levelized Busbar Cost (c/kWh)				**8.36**
							Net Levelized Cost ($000s)				**73,126**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-17 Busbar Cost Model for Option 15SD at a 90 Percent Capacity Factor

Option 16: 112 MW - 2x1 LM6000 PF+ CC w/o DF at CPGS

25-Year Busbar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 161,504	First Year Fixed O&M Cost ($/kW-yr)	37.0	1.5%
Other Owner Costs, except Esc & IDC	$ 40,320	First Year Variable O&M ($/MWh)	5.20	1.5%
Total Capital Cost (with Esc & IDC)	$ 201,824	Fuel Rate ($/MMBTU)	3.21	
Total Net Output, Avg Ambient Cond. (kW)	112,000	Construction Period (months)		
Capacity Factor	90.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	7,050	Levelized Fixed Charge Rate (25 yr)	13.7%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	27,549	4,144	4,592	3.21	19,965	0	0	56,250	52,199	6.37	5.91
2022	27,549	4,206	4,661	3.07	19,093	0	0	55,508	47,802	6.29	5.41
2023	27,549	4,269	4,730	3.43	21,343	0	0	57,892	46,264	6.56	5.24
2024	27,549	4,333	4,801	3.78	23,528	0	0	60,212	44,653	6.82	5.06
2025	27,549	4,398	4,873	4.04	25,123	0	0	61,944	42,629	7.02	4.83
2026	27,549	4,464	4,947	4.12	25,646	0	0	62,606	39,982	7.09	4.53
2027	27,549	4,531	5,021	4.11	25,579	0	0	62,680	37,147	7.10	4.21
2028	27,549	4,599	5,096	4.23	26,326	0	0	63,570	34,962	7.20	3.96
2029	27,549	4,668	5,172	4.27	26,576	0	0	63,965	32,646	7.24	3.70
2030	27,549	4,738	5,250	4.31	26,848	0	0	64,385	30,493	7.29	3.45
2031	27,549	4,809	5,329	4.47	27,855	0	0	65,542	28,806	7.42	3.26
2032	27,549	4,881	5,409	4.56	28,403	0	0	66,242	27,017	7.50	3.06
2033	27,549	4,955	5,490	4.64	28,916	0	0	66,909	25,324	7.58	2.87
2034	27,549	5,029	5,572	4.79	29,791	0	0	67,941	23,863	7.69	2.70
2035	27,549	5,104	5,656	5.09	31,661	0	0	69,970	22,806	7.92	2.58
2036	27,549	5,181	5,741	5.36	33,363	0	0	71,834	21,727	8.14	2.46
2037	27,549	5,259	5,827	5.66	35,223	0	0	73,857	20,731	8.36	2.35
2038	27,549	5,338	5,914	5.95	37,042	0	0	75,843	19,755	8.59	2.24
2039	27,549	5,418	6,003	6.15	38,258	0	0	77,228	18,667	8.75	2.11
2040	27,549	5,499	6,093	6.42	39,988	0	0	79,128	17,749	8.96	2.01
2041	27,549	5,581	6,184	6.67	41,517	0	0	80,832	16,826	9.15	1.91
2042	27,549	5,665	6,277	6.80	42,361	0	0	81,852	15,811	9.27	1.79
2043	27,549	5,750	6,371	6.99	43,517	0	0	83,188	14,912	9.42	1.69
2044	27,549	5,836	6,467	7.37	45,901	0	0	85,753	14,265	9.71	1.62
2045	27,549	5,924	6,564	7.77	48,355	0	0	88,392	13,645	10.01	1.55
							Net Levelized Busbar Cost (c/kWh)				**7.39**
							Net Levelized Cost ($000s)				**65,216**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-18 Busbar Cost Model for Option 16 at a 90 Percent Capacity Factor

Option 17W: 73 MW - 1x1 LM6000 PF+ CC with DF at CPGS				
25-Year Busbar Cost Calculation				
Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 96,214	First Year Fixed O&M Cost ($/kW-yr)	50.0	1.5%
Other Owner Costs, except Esc & IDC	$ 24,090	First Year Variable O&M ($/MWh)	6.70	1.5%
Total Capital Cost (with Esc & IDC)	$ 120,304	Fuel Rate ($/MMBTU)	3.21	
Total Net Output, Avg Ambient Cond. (kW)	73,000	Construction Period (months)		
Capacity Factor	90.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	7,850	Levelized Fixed Charge Rate (25 yr)	13.7%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	16,421	3,650	3,856	3.21	14,490	0	0	38,417	35,651	6.68	6.19
2022	16,421	3,705	3,914	3.07	13,856	0	0	37,897	32,635	6.58	5.67
2023	16,421	3,760	3,973	3.43	15,490	0	0	39,644	31,681	6.89	5.50
2024	16,421	3,817	4,032	3.78	17,076	0	0	41,346	30,662	7.18	5.33
2025	16,421	3,874	4,093	4.04	18,233	0	0	42,621	29,332	7.41	5.10
2026	16,421	3,932	4,154	4.12	18,613	0	0	43,120	27,538	7.49	4.78
2027	16,421	3,991	4,216	4.11	18,564	0	0	43,193	25,598	7.50	4.45
2028	16,421	4,051	4,280	4.23	19,106	0	0	43,858	24,121	7.62	4.19
2029	16,421	4,112	4,344	4.27	19,287	0	0	44,164	22,540	7.67	3.92
2030	16,421	4,173	4,409	4.31	19,485	0	0	44,488	21,070	7.73	3.66
2031	16,421	4,236	4,475	4.47	20,216	0	0	45,348	19,931	7.88	3.46
2032	16,421	4,300	4,542	4.56	20,613	0	0	45,876	18,711	7.97	3.25
2033	16,421	4,364	4,610	4.64	20,986	0	0	46,382	17,555	8.06	3.05
2034	16,421	4,429	4,680	4.79	21,621	0	0	47,151	16,561	8.19	2.88
2035	16,421	4,496	4,750	5.09	22,978	0	0	48,645	15,855	8.45	2.75
2036	16,421	4,563	4,821	5.36	24,213	0	0	50,019	15,129	8.69	2.63
2037	16,421	4,632	4,893	5.66	25,563	0	0	51,509	14,458	8.95	2.51
2038	16,421	4,701	4,967	5.95	26,883	0	0	52,973	13,798	9.20	2.40
2039	16,421	4,772	5,041	6.15	27,766	0	0	54,000	13,053	9.38	2.27
2040	16,421	4,843	5,117	6.42	29,021	0	0	55,403	12,427	9.63	2.16
2041	16,421	4,916	5,194	6.67	30,131	0	0	56,662	11,795	9.85	2.05
2042	16,421	4,990	5,271	6.80	30,743	0	0	57,426	11,093	9.98	1.93
2043	16,421	5,065	5,351	6.99	31,583	0	0	58,419	10,472	10.15	1.82
2044	16,421	5,141	5,431	7.37	33,313	0	0	60,306	10,032	10.48	1.74
2045	16,421	5,218	5,512	7.77	35,094	0	0	62,245	9,609	10.82	1.67
							Net Levelized Busbar Cost (c/kWh)				**7.83**
							Net Levelized Cost ($000s)				**45,085**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-19 Busbar Cost Model for Option 17W at a 90 Percent Capacity Factor

Option 17SD: 73 MW - 1x1 LM6000 PF+ CC with DF - Rapid City											
25-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 96,214		First Year Fixed O&M Cost ($/kW-yr)				50.0	1.5%
Other Owner Costs, except Esc & IDC				$ 24,090		First Year Variable O&M ($/MWh)				6.70	1.5%
Total Capital Cost (with Esc & IDC)				$ 120,304		Fuel Rate ($/MMBTU)				4.34	
Total Net Output, Avg Ambient Cond. (kW)				73,000		Construction Period (months)					
Capacity Factor				90.0%		Present Worth Discount Rate				7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				7,850		Levelized Fixed Charge Rate (25 yr)				13.7%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	16,421	3,650	3,856	4.34	19,629	0	0	43,557	40,420	7.57	7.02
2022	16,421	3,705	3,914	4.21	19,027	0	0	43,067	37,088	7.48	6.44
2023	16,421	3,760	3,973	4.61	20,829	0	0	44,984	35,949	7.82	6.25
2024	16,421	3,817	4,032	5.00	22,568	0	0	46,839	34,735	8.14	6.04
2025	16,421	3,874	4,093	5.28	23,863	0	0	48,251	33,206	8.38	5.77
2026	16,421	3,932	4,154	5.38	24,310	0	0	48,818	31,177	8.48	5.42
2027	16,421	3,991	4,216	5.39	24,351	0	0	48,979	29,028	8.51	5.04
2028	16,421	4,051	4,280	5.53	24,975	0	0	49,727	27,348	8.64	4.75
2029	16,421	4,112	4,344	5.59	25,244	0	0	50,121	25,580	8.71	4.44
2030	16,421	4,173	4,409	5.64	25,474	0	0	50,478	23,907	8.77	4.15
2031	16,421	4,236	4,475	5.82	26,310	0	0	51,442	22,609	8.94	3.93
2032	16,421	4,300	4,542	5.94	26,825	0	0	52,088	21,244	9.05	3.69
2033	16,421	4,364	4,610	6.04	27,270	0	0	52,666	19,933	9.15	3.46
2034	16,421	4,429	4,680	6.21	28,055	0	0	53,585	18,821	9.31	3.27
2035	16,421	4,496	4,750	6.54	29,550	0	0	55,217	17,997	9.59	3.13
2036	16,421	4,563	4,821	6.84	30,923	0	0	56,729	17,159	9.86	2.98
2037	16,421	4,632	4,893	7.18	32,452	0	0	58,399	16,392	10.15	2.85
2038	16,421	4,701	4,967	7.51	33,941	0	0	60,030	15,636	10.43	2.72
2039	16,421	4,772	5,041	7.74	34,990	0	0	61,225	14,799	10.64	2.57
2040	16,421	4,843	5,117	8.06	36,395	0	0	62,777	14,081	10.91	2.45
2041	16,421	4,916	5,194	8.33	37,649	0	0	64,180	13,360	11.15	2.32
2042	16,421	4,990	5,271	8.49	38,356	0	0	65,039	12,563	11.30	2.18
2043	16,421	5,065	5,351	8.71	39,366	0	0	66,203	11,867	11.50	2.06
2044	16,421	5,141	5,431	9.14	41,304	0	0	68,297	11,361	11.87	1.97
2045	16,421	5,218	5,512	9.59	43,316	0	0	70,468	10,878	12.24	1.89
							Net Levelized Bus-bar Cost (c/kWh)				**8.88**
							Net Levelized Cost ($000s)				**51,126**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-20 Busbar Cost Model for Option 17SD at a 90 Percent Capacity Factor

Option 18W: 91 MW - 1x0 LMS100 CT - Cheyenne

25-Year Busbar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 98,462	First Year Fixed O&M Cost ($/kW-yr)	18.0	1.5%
Other Owner Costs, except Esc & IDC	$ 21,658	First Year Variable O&M ($/MWh)	5.30	1.5%
Total Capital Cost (with Esc & IDC)	$ 120,120	Fuel Rate ($/MMBTU)	3.21	
Total Net Output, Avg Ambient Cond. (kW)	91,000	Construction Period (months)		
Capacity Factor	35.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	8,750	Levelized Fixed Charge Rate (25 yr)	14.4%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	17,309	1,638	1,479	3.21	7,830	0	0	28,256	26,221	10.13	9.40
2022	17,309	1,663	1,501	3.07	7,487	0	0	27,960	24,078	10.02	8.63
2023	17,309	1,688	1,523	3.43	8,370	0	0	28,890	23,088	10.35	8.27
2024	17,309	1,713	1,546	3.78	9,227	0	0	29,795	22,096	10.68	7.92
2025	17,309	1,739	1,569	4.04	9,852	0	0	30,470	20,969	10.92	7.52
2026	17,309	1,765	1,593	4.12	10,057	0	0	30,724	19,622	11.01	7.03
2027	17,309	1,791	1,617	4.11	10,031	0	0	30,749	18,223	11.02	6.53
2028	17,309	1,818	1,641	4.23	10,324	0	0	31,093	17,100	11.14	6.13
2029	17,309	1,845	1,666	4.27	10,422	0	0	31,242	15,945	11.20	5.71
2030	17,309	1,873	1,691	4.31	10,529	0	0	31,402	14,872	11.25	5.33
2031	17,309	1,901	1,716	4.47	10,924	0	0	31,850	13,998	11.42	5.02
2032	17,309	1,929	1,742	4.56	11,139	0	0	32,119	13,100	11.51	4.70
2033	17,309	1,958	1,768	4.64	11,340	0	0	32,375	12,254	11.60	4.39
2034	17,309	1,988	1,795	4.79	11,683	0	0	32,775	11,511	11.75	4.13
2035	17,309	2,018	1,821	5.09	12,416	0	0	33,565	10,940	12.03	3.92
2036	17,309	2,048	1,849	5.36	13,084	0	0	34,290	10,372	12.29	3.72
2037	17,309	2,079	1,876	5.66	13,813	0	0	35,077	9,846	12.57	3.53
2038	17,309	2,110	1,905	5.95	14,527	0	0	35,850	9,338	12.85	3.35
2039	17,309	2,141	1,933	6.15	15,003	0	0	36,387	8,795	13.04	3.15
2040	17,309	2,174	1,962	6.42	15,682	0	0	37,127	8,328	13.31	2.98
2041	0	2,206	1,992	6.67	16,282	0	0	20,479	4,263	7.34	1.53
2042	0	2,239	2,022	6.80	16,612	0	0	20,873	4,032	7.48	1.45
2043	0	2,273	2,052	6.99	17,066	0	0	21,391	3,834	7.67	1.37
2044	0	2,307	2,083	7.37	18,001	0	0	22,390	3,725	8.03	1.33
2045	0	2,342	2,114	7.77	18,963	0	0	23,419	3,615	8.39	1.30
							Net Levelized Busbar Cost (c/kWh)				**10.86**
							Net Levelized Cost ($000s)				**30,298**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-21 Busbar Cost Model for Option 18W at a 35 Percent Capacity Factor

Option 18SD: 91 MW - 1x0 LMS100 CT - Rapid City

25-Year Busbar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 98,462	First Year Fixed O&M Cost ($/kW-yr)	18.0	1.5%
Other Owner Costs, except Esc & IDC	$ 21,658	First Year Variable O&M ($/MWh)	5.30	1.5%
Total Capital Cost (with Esc & IDC)	$ 120,120	Fuel Rate ($/MMBTU)	4.34	
Total Net Output, Avg Ambient Cond. (kW)	91,000	Construction Period (months)		
Capacity Factor	35.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	8,750	Levelized Fixed Charge Rate (25 yr)	14.4%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	17,309	1,638	1,479	4.34	10,607	0	0	31,033	28,798	11.12	10.32
2022	17,309	1,663	1,501	4.21	10,282	0	0	30,754	26,484	11.02	9.49
2023	17,309	1,688	1,523	4.61	11,255	0	0	31,776	25,393	11.39	9.10
2024	17,309	1,713	1,546	5.00	12,195	0	0	32,763	24,297	11.74	8.71
2025	17,309	1,739	1,569	5.28	12,894	0	0	33,512	23,063	12.01	8.27
2026	17,309	1,765	1,593	5.38	13,136	0	0	33,803	21,588	12.12	7.74
2027	17,309	1,791	1,617	5.39	13,158	0	0	33,875	20,076	12.14	7.20
2028	17,309	1,818	1,641	5.53	13,495	0	0	34,264	18,844	12.28	6.75
2029	17,309	1,845	1,666	5.59	13,641	0	0	34,461	17,588	12.35	6.30
2030	17,309	1,873	1,691	5.64	13,765	0	0	34,638	16,405	12.41	5.88
2031	17,309	1,901	1,716	5.82	14,217	0	0	35,143	15,446	12.60	5.54
2032	17,309	1,929	1,742	5.94	14,495	0	0	35,476	14,469	12.71	5.19
2033	17,309	1,958	1,768	6.04	14,736	0	0	35,771	13,539	12.82	4.85
2034	17,309	1,988	1,795	6.21	15,160	0	0	36,251	12,733	12.99	4.56
2035	17,309	2,018	1,821	6.54	15,967	0	0	37,116	12,097	13.30	4.34
2036	17,309	2,048	1,849	6.84	16,710	0	0	37,916	11,468	13.59	4.11
2037	17,309	2,079	1,876	7.18	17,536	0	0	38,800	10,891	13.91	3.90
2038	17,309	2,110	1,905	7.51	18,340	0	0	39,664	10,331	14.22	3.70
2039	17,309	2,141	1,933	7.74	18,907	0	0	40,291	9,739	14.44	3.49
2040	17,309	2,174	1,962	8.06	19,666	0	0	41,111	9,222	14.73	3.31
2041	0	2,206	1,992	8.33	20,344	0	0	24,542	5,109	8.80	1.83
2042	0	2,239	2,022	8.49	20,726	0	0	24,987	4,827	8.96	1.73
2043	0	2,273	2,052	8.71	21,272	0	0	25,596	4,588	9.17	1.64
2044	0	2,307	2,083	9.14	22,319	0	0	26,709	4,443	9.57	1.59
2045	0	2,342	2,114	9.59	23,406	0	0	27,862	4,301	9.99	1.54
								Net Levelized Bus-bar Cost (c/kWh)			**12.03**
								Net Levelized Cost ($000s)			**33,562**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-22 Busbar Cost Model for Option 18SD at a 35 Percent Capacity Factor

Option 19W: 42 MW - 1x0 LM6000 PF+ CT - Cheyenne				
25-Year Busbar Cost Calculation				
Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 52,458	First Year Fixed O&M Cost ($/kW-yr)	43.0	1.5%
Other Owner Costs, except Esc & IDC	$ 11,550	First Year Variable O&M ($/MWh)	7.80	1.5%
Total Capital Cost (with Esc & IDC)	$ 64,008	Fuel Rate ($/MMBTU)	3.21	
Total Net Output, Avg Ambient Cond. (kW)	42,000	Construction Period (months)		
Capacity Factor	35.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	9,400	Levelized Fixed Charge Rate (25 yr)	14.4%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	9,224	1,806	1,004	3.21	3,882	0	0	15,916	14,770	12.36	11.47
2022	9,224	1,833	1,019	3.07	3,712	0	0	15,789	13,597	12.26	10.56
2023	9,224	1,861	1,035	3.43	4,150	0	0	16,269	13,001	12.63	10.10
2024	9,224	1,888	1,050	3.78	4,575	0	0	16,737	12,412	13.00	9.64
2025	9,224	1,917	1,066	4.04	4,885	0	0	17,091	11,762	13.27	9.13
2026	9,224	1,946	1,082	4.12	4,987	0	0	17,238	11,009	13.39	8.55
2027	9,224	1,975	1,098	4.11	4,974	0	0	17,270	10,235	13.41	7.95
2028	9,224	2,004	1,115	4.23	5,119	0	0	17,462	9,603	13.56	7.46
2029	9,224	2,034	1,131	4.27	5,168	0	0	17,557	8,960	13.63	6.96
2030	9,224	2,065	1,148	4.31	5,220	0	0	17,657	8,363	13.71	6.49
2031	9,224	2,096	1,166	4.47	5,416	0	0	17,901	7,868	13.90	6.11
2032	9,224	2,127	1,183	4.56	5,523	0	0	18,057	7,365	14.02	5.72
2033	9,224	2,159	1,201	4.64	5,623	0	0	18,206	6,891	14.14	5.35
2034	9,224	2,192	1,219	4.79	5,793	0	0	18,427	6,472	14.31	5.03
2035	9,224	2,225	1,237	5.09	6,156	0	0	18,842	6,141	14.63	4.77
2036	9,224	2,258	1,256	5.36	6,487	0	0	19,225	5,815	14.93	4.52
2037	9,224	2,292	1,275	5.66	6,849	0	0	19,639	5,512	15.25	4.28
2038	9,224	2,326	1,294	5.95	7,203	0	0	20,046	5,221	15.57	4.05
2039	9,224	2,361	1,313	6.15	7,439	0	0	20,337	4,916	15.79	3.82
2040	9,224	2,396	1,333	6.42	7,775	0	0	20,728	4,650	16.10	3.61
2041	0	2,432	1,353	6.67	8,073	0	0	11,858	2,468	9.21	1.92
2042	0	2,469	1,373	6.80	8,237	0	0	12,079	2,333	9.38	1.81
2043	0	2,506	1,394	6.99	8,462	0	0	12,361	2,216	9.60	1.72
2044	0	2,544	1,415	7.37	8,925	0	0	12,883	2,143	10.00	1.66
2045	0	2,582	1,436	7.77	9,402	0	0	13,420	2,072	10.42	1.61
							Net Levelized Busbar Cost (c/kWh)				**13.24**
							Net Levelized Cost ($000s)				**17,050**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-23 Busbar Cost Model for Option 19W at a 35 Percent Capacity Factor

Option 19SD: 42 MW - 1x0 LM6000 PF+ CT - Rapid City											
25-Year Busbar Cost Calculation											
Plant Input Data					Economic Input Data					Rate	Escalation
EPC Capital Cost ($1000)				$ 52,458	First Year Fixed O&M Cost ($/kW-yr)					43.0	1.5%
Other Owner Costs, except Esc & IDC				$ 11,550	First Year Variable O&M ($/MWh)					7.80	1.5%
Total Capital Cost (with Esc & IDC)				$ 64,008	Fuel Rate ($/MMBTU)					4.34	
Total Net Output, Avg Ambient Cond. (kW)				42,000	Construction Period (months)						
Capacity Factor				35.0%	Present Worth Discount Rate					7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				9,400	Levelized Fixed Charge Rate (25 yr)					14.4%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	9,224	1,806	1,004	4.34	5,259	0	0	17,293	16,048	13.43	12.46
2022	9,224	1,833	1,019	4.21	5,098	0	0	17,174	14,790	13.34	11.49
2023	9,224	1,861	1,035	4.61	5,581	0	0	17,700	14,145	13.74	10.98
2024	9,224	1,888	1,050	5.00	6,047	0	0	18,209	13,504	14.14	10.49
2025	9,224	1,917	1,066	5.28	6,393	0	0	18,600	12,800	14.44	9.94
2026	9,224	1,946	1,082	5.38	6,513	0	0	18,764	11,984	14.57	9.31
2027	9,224	1,975	1,098	5.39	6,524	0	0	18,821	11,154	14.62	8.66
2028	9,224	2,004	1,115	5.53	6,691	0	0	19,034	10,468	14.78	8.13
2029	9,224	2,034	1,131	5.59	6,763	0	0	19,153	9,775	14.87	7.59
2030	9,224	2,065	1,148	5.64	6,825	0	0	19,262	9,123	14.96	7.08
2031	9,224	2,096	1,166	5.82	7,049	0	0	19,534	8,585	15.17	6.67
2032	9,224	2,127	1,183	5.94	7,187	0	0	19,721	8,043	15.31	6.25
2033	9,224	2,159	1,201	6.04	7,306	0	0	19,890	7,528	15.45	5.85
2034	9,224	2,192	1,219	6.21	7,517	0	0	20,151	7,078	15.65	5.50
2035	9,224	2,225	1,237	6.54	7,917	0	0	20,602	6,715	16.00	5.21
2036	9,224	2,258	1,256	6.84	8,285	0	0	21,022	6,359	16.33	4.94
2037	9,224	2,292	1,275	7.18	8,695	0	0	21,485	6,030	16.68	4.68
2038	9,224	2,326	1,294	7.51	9,093	0	0	21,937	5,714	17.04	4.44
2039	9,224	2,361	1,313	7.74	9,375	0	0	22,272	5,384	17.30	4.18
2040	9,224	2,396	1,333	8.06	9,751	0	0	22,704	5,093	17.63	3.95
2041	0	2,432	1,353	8.33	10,087	0	0	13,872	2,888	10.77	2.24
2042	0	2,469	1,373	8.49	10,276	0	0	14,118	2,727	10.96	2.12
2043	0	2,506	1,394	8.71	10,547	0	0	14,447	2,590	11.22	2.01
2044	0	2,544	1,415	9.14	11,066	0	0	15,024	2,499	11.67	1.94
2045	0	2,582	1,436	9.59	11,605	0	0	15,623	2,412	12.13	1.87
							Net Levelized Busbar Cost (c/kWh)				**14.50**
							Net Levelized Cost ($000s)				**18,668**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-24 Busbar Cost Model for Option 19SD at a 35 Percent Capacity Factor

Option 20W: 75 MW - 1x0 7EA CT - Cheyenne											
25-Year Bus-bar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 93,675		First Year Fixed O&M Cost ($/kW-yr)				43.0	1.5%
Other Owner Costs, except Esc & IDC				$ 20,625		First Year Variable O&M ($/MWh)				7.80	1.5%
Total Capital Cost (with Esc & IDC)				$ 114,300		Fuel Rat(($/MMBTU)				3.21	
Total Net Output, Avg Ambient Cond. (kW)				75,000		Construction Period (months)					
Capacity Factor				35.0%		Present Worth Discount Rate				7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				11,200		Levelized Fixed Charge Rate (25 yr)				14.4%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	16,471	3,225	1,794	3.21	8,260	0	0	29,749	27,607	12.94	12.01
2022	16,471	3,273	1,821	3.07	7,899	0	0	29,463	25,373	12.81	11.03
2023	16,471	3,322	1,848	3.43	8,830	0	0	30,471	24,351	13.25	10.59
2024	16,471	3,372	1,876	3.78	9,734	0	0	31,452	23,325	13.68	10.14
2025	16,471	3,423	1,904	4.04	10,394	0	0	32,191	22,154	14.00	9.63
2026	16,471	3,474	1,932	4.12	10,610	0	0	32,487	20,748	14.13	9.02
2027	16,471	3,526	1,961	4.11	10,583	0	0	32,541	19,285	14.15	8.39
2028	16,471	3,579	1,991	4.23	10,891	0	0	32,932	18,112	14.32	7.88
2029	16,471	3,633	2,020	4.27	10,995	0	0	33,119	16,903	14.40	7.35
2030	16,471	3,687	2,051	4.31	11,107	0	0	33,316	15,779	14.49	6.86
2031	16,471	3,743	2,082	4.47	11,524	0	0	33,819	14,864	14.71	6.46
2032	16,471	3,799	2,113	4.56	11,751	0	0	34,133	13,921	14.84	6.05
2033	16,471	3,856	2,144	4.64	11,963	0	0	34,434	13,033	14.97	5.67
2034	16,471	3,914	2,177	4.79	12,325	0	0	34,886	12,253	15.17	5.33
2035	16,471	3,972	2,209	5.09	13,099	0	0	35,751	11,653	15.55	5.07
2036	16,471	4,032	2,242	5.36	13,803	0	0	36,548	11,055	15.89	4.81
2037	16,471	4,092	2,276	5.66	14,572	0	0	37,411	10,501	16.27	4.57
2038	16,471	4,154	2,310	5.95	15,325	0	0	38,259	9,966	16.64	4.33
2039	16,471	4,216	2,345	6.15	15,828	0	0	38,859	9,393	16.90	4.08
2040	16,471	4,279	2,380	6.42	16,543	0	0	39,673	8,899	17.25	3.87
2041	0	4,344	2,416	6.67	17,176	0	0	23,936	4,982	10.41	2.17
2042	0	4,409	2,452	6.80	17,525	0	0	24,386	4,711	10.60	2.05
2043	0	4,475	2,489	6.99	18,004	0	0	24,967	4,476	10.86	1.95
2044	0	4,542	2,526	7.37	18,990	0	0	26,058	4,335	11.33	1.89
2045	0	4,610	2,564	7.77	20,005	0	0	27,179	4,196	11.82	1.82
							Net Levelized Busbar Cost (c/kWh)				**14.04**
							Net Levelized Cost ($000s)				**32,290**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-25 Busbar Cost Model for Option 20W at a 35 Percent Capacity Factor

Option 20SD: 75 MW - 1x0 7EA CT - Rapid City					
25-Year Busbar Cost Calculation					
Plant Input Data		Economic Input Data		Rate	Escalation
EPC Capital Cost ($1000)	$ 93,675	First Year Fixed O&M Cost ($/kW-yr)		43.0	1.5%
Other Owner Costs, except Esc & IDC	$ 20,625	First Year Variable O&M ($/MWh)		7.80	1.5%
Total Capital Cost (with Esc & IDC)	$ 114,300	Fuel Rate ($/MMBTU)		4.34	
Total Net Output, Avg Ambient Cond. (kW)	75,000	Construction Period (months)			
Capacity Factor	35.0%	Present Worth Discount Rate		7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	11,200	Levelized Fixed Charge Rate (25 yr)		14.4%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	16,471	3,225	1,794	4.34	11,190	0	0	32,679	30,325	14.21	13.19
2022	16,471	3,273	1,821	4.21	10,846	0	0	32,411	27,911	14.09	12.14
2023	16,471	3,322	1,848	4.61	11,874	0	0	33,515	26,783	14.57	11.65
2024	16,471	3,372	1,876	5.00	12,865	0	0	34,583	25,647	15.04	11.15
2025	16,471	3,423	1,904	5.28	13,603	0	0	35,400	24,362	15.39	10.59
2026	16,471	3,474	1,932	5.38	13,858	0	0	35,735	22,822	15.54	9.92
2027	16,471	3,526	1,961	5.39	13,881	0	0	35,839	21,240	15.59	9.24
2028	16,471	3,579	1,991	5.53	14,237	0	0	36,277	19,952	15.78	8.68
2029	16,471	3,633	2,020	5.59	14,390	0	0	36,514	18,636	15.88	8.10
2030	16,471	3,687	2,051	5.64	14,521	0	0	36,730	17,396	15.97	7.57
2031	16,471	3,743	2,082	5.82	14,998	0	0	37,293	16,390	16.22	7.13
2032	16,471	3,799	2,113	5.94	15,291	0	0	37,674	15,365	16.38	6.68
2033	16,471	3,856	2,144	6.04	15,545	0	0	38,016	14,389	16.53	6.26
2034	16,471	3,914	2,177	6.21	15,993	0	0	38,554	13,541	16.77	5.89
2035	16,471	3,972	2,209	6.54	16,845	0	0	39,497	12,874	17.18	5.60
2036	16,471	4,032	2,242	6.84	17,628	0	0	40,373	12,211	17.56	5.31
2037	16,471	4,092	2,276	7.18	18,499	0	0	41,339	11,603	17.98	5.05
2038	16,471	4,154	2,310	7.51	19,348	0	0	42,283	11,013	18.39	4.79
2039	16,471	4,216	2,345	7.74	19,946	0	0	42,978	10,388	18.69	4.52
2040	16,471	4,279	2,380	8.06	20,747	0	0	43,877	9,842	19.08	4.28
2041	0	4,344	2,416	8.33	21,462	0	0	28,221	5,874	12.27	2.55
2042	0	4,409	2,452	8.49	21,865	0	0	28,726	5,549	12.49	2.41
2043	0	4,475	2,489	8.71	22,441	0	0	29,404	5,271	12.79	2.29
2044	0	4,542	2,526	9.14	23,545	0	0	30,614	5,093	13.31	2.21
2045	0	4,610	2,564	9.59	24,692	0	0	31,867	4,919	13.86	2.14
							Net Levelized Busbar Cost (c/kWh)				**15.54**
							Net Levelized Cost ($000s)				**35,733**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-26 Busbar Cost Model for Option 20SD at a 35 Percent Capacity Factor

Option 21GW: 200 MW - Solar PV SAT - Gillette, WY											
25-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 220,200		First Year Fixed O&M Cost ($/kW-yr)				7.0	1.5%
Other Owner Costs, except Esc & IDC				$ 44,000		First Year Variable O&M ($/MWh)				0.00	1.5%
Total Capital Cost (with Esc & IDC)				$ 264,200		Fuel Rate ($/MMBTU)				0.00	
Total Net Output, Avg Ambient Cond. (kW)				200,000		Construction Period (months)					
Capacity Factor				21.7%		Present Worth Discount Rate				7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				0		Levelized Fixed Charge Rate (25 yr)				12.5%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	33,131	1,400	0	0.00	0	0	0	34,531	32,044	9.08	8.43
2022	33,131	1,421	0	0.00	0	0	0	34,552	29,755	9.09	7.83
2023	33,131	1,442	0	0.00	0	0	0	34,573	27,629	9.09	7.27
2024	33,131	1,464	0	0.00	0	0	0	34,595	25,655	9.10	6.75
2025	33,131	1,486	0	0.00	0	0	0	34,617	23,823	9.11	6.27
2026	33,131	1,508	0	0.00	0	0	0	34,639	22,122	9.11	5.82
2027	33,131	1,531	0	0.00	0	0	0	34,662	20,542	9.12	5.40
2028	33,131	1,554	0	0.00	0	0	0	34,684	19,075	9.12	5.02
2029	33,131	1,577	0	0.00	0	0	0	34,708	17,714	9.13	4.66
2030	33,131	1,601	0	0.00	0	0	0	34,731	16,449	9.14	4.33
2031	33,131	1,625	0	0.00	0	0	0	34,755	15,275	9.14	4.02
2032	33,131	1,649	0	0.00	0	0	0	34,780	14,185	9.15	3.73
2033	33,131	1,674	0	0.00	0	0	0	34,805	13,173	9.15	3.46
2034	33,131	1,699	0	0.00	0	0	0	34,830	12,233	9.16	3.22
2035	33,131	1,724	0	0.00	0	0	0	34,855	11,361	9.17	2.99
2036	33,131	1,750	0	0.00	0	0	0	34,881	10,550	9.17	2.78
2037	33,131	1,777	0	0.00	0	0	0	34,907	9,798	9.18	2.58
2038	33,131	1,803	0	0.00	0	0	0	34,934	9,099	9.19	2.39
2039	33,131	1,830	0	0.00	0	0	0	34,961	8,451	9.20	2.22
2040	33,131	1,858	0	0.00	0	0	0	34,988	7,848	9.20	2.06
2041	0	1,886	0	0.00	0	0	0	1,886	392	0.50	0.10
2042	0	1,914	0	0.00	0	0	0	1,914	370	0.50	0.10
2043	0	1,943	0	0.00	0	0	0	1,943	348	0.51	0.09
2044	0	1,972	0	0.00	0	0	0	1,972	328	0.52	0.09
2045	0	2,001	0	0.00	0	0	0	2,001	309	0.53	0.08
							Net Levelized Busbar Cost (c/kWh)				**8.41**
							Net Levelized Cost ($000s)				**31,983**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-27 Busbar Cost Model for Option 21GW at a 21.7 Percent Capacity Factor

Option 21SD: 200 MW - Solar PV SAT - Hot Springs, SD											
25-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 220,200		First Year Fixed O&M Cost ($/kW-yr)				7.0	1.5%
Other Owner Costs, except Esc & IDC				$ 44,000		First Year Variable O&M ($/MWh)				0.00	1.5%
Total Capital Cost (with Esc & IDC)				$ 264,200		Fuel Rat(($/MMBTU)				0.00	
Total Net Output, Avg Ambient Cond. (kW)				200,000		Construction Period (months)					
Capacity Factor				24.6%		Present Worth Discount Rate				7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				0		Levelized Fixed Charge Rate (25 yr)				12.5%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	33,131	1,400	0	0.00	0	0	0	34,531	32,044	8.01	7.43
2022	33,131	1,421	0	0.00	0	0	0	34,552	29,755	8.02	6.90
2023	33,131	1,442	0	0.00	0	0	0	34,573	27,629	8.02	6.41
2024	33,131	1,464	0	0.00	0	0	0	34,595	25,655	8.03	5.95
2025	33,131	1,486	0	0.00	0	0	0	34,617	23,823	8.03	5.53
2026	33,131	1,508	0	0.00	0	0	0	34,639	22,122	8.04	5.13
2027	33,131	1,531	0	0.00	0	0	0	34,662	20,542	8.04	4.77
2028	33,131	1,554	0	0.00	0	0	0	34,684	19,075	8.05	4.43
2029	33,131	1,577	0	0.00	0	0	0	34,708	17,714	8.05	4.11
2030	33,131	1,601	0	0.00	0	0	0	34,731	16,449	8.06	3.82
2031	33,131	1,625	0	0.00	0	0	0	34,755	15,275	8.06	3.54
2032	33,131	1,649	0	0.00	0	0	0	34,780	14,185	8.07	3.29
2033	33,131	1,674	0	0.00	0	0	0	34,805	13,173	8.08	3.06
2034	33,131	1,699	0	0.00	0	0	0	34,830	12,233	8.08	2.84
2035	33,131	1,724	0	0.00	0	0	0	34,855	11,361	8.09	2.64
2036	33,131	1,750	0	0.00	0	0	0	34,881	10,550	8.09	2.45
2037	33,131	1,777	0	0.00	0	0	0	34,907	9,798	8.10	2.27
2038	33,131	1,803	0	0.00	0	0	0	34,934	9,099	8.11	2.11
2039	33,131	1,830	0	0.00	0	0	0	34,961	8,451	8.11	1.96
2040	33,131	1,858	0	0.00	0	0	0	34,988	7,848	8.12	1.82
2041	0	1,886	0	0.00	0	0	0	1,886	392	0.44	0.09
2042	0	1,914	0	0.00	0	0	0	1,914	370	0.44	0.09
2043	0	1,943	0	0.00	0	0	0	1,943	348	0.45	0.08
2044	0	1,972	0	0.00	0	0	0	1,972	328	0.46	0.08
2045	0	2,001	0	0.00	0	0	0	2,001	309	0.46	0.07
						Net Levelized Busbar Cost (c/kWh)					**7.42**
						Net Levelized Cost ($000s)					**31,983**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-28 Busbar Cost Model for Option 21SD at a 24.6 Percent Capacity Factor

Option 21CW: 200 MW - Solar PV SAT - Cheyenne, WY			
25-Year Busbar Cost Calculation			
Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 220,200	First Year Fixed O&M Cost ($/kW-yr)	7.0	1.5%
Other Owner Costs, except Esc & IDC	$ 44,000	First Year Variable O&M ($/MWh)	0.00	1.5%
Total Capital Cost (with Esc & IDC)	$ 264,200	Fuel Rate ($/MMBTU)	0.00	
Total Net Output, Avg Ambient Cond. (kW)	200,000	Construction Period (months)		
Capacity Factor	23.1%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	0	Levelized Fixed Charge Rate (25 yr)	12.5%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	33,131	1,400	0	0.00	0	0	0	34,531	32,044	8.53	7.92
2022	33,131	1,421	0	0.00	0	0	0	34,552	29,755	8.54	7.35
2023	33,131	1,442	0	0.00	0	0	0	34,573	27,629	8.54	6.83
2024	33,131	1,464	0	0.00	0	0	0	34,595	25,655	8.55	6.34
2025	33,131	1,486	0	0.00	0	0	0	34,617	23,823	8.55	5.89
2026	33,131	1,508	0	0.00	0	0	0	34,639	22,122	8.56	5.47
2027	33,131	1,531	0	0.00	0	0	0	34,662	20,542	8.56	5.08
2028	33,131	1,554	0	0.00	0	0	0	34,684	19,075	8.57	4.71
2029	33,131	1,577	0	0.00	0	0	0	34,708	17,714	8.58	4.38
2030	33,131	1,601	0	0.00	0	0	0	34,731	16,449	8.58	4.06
2031	33,131	1,625	0	0.00	0	0	0	34,755	15,275	8.59	3.77
2032	33,131	1,649	0	0.00	0	0	0	34,780	14,185	8.59	3.51
2033	33,131	1,674	0	0.00	0	0	0	34,805	13,173	8.60	3.25
2034	33,131	1,699	0	0.00	0	0	0	34,830	12,233	8.61	3.02
2035	33,131	1,724	0	0.00	0	0	0	34,855	11,361	8.61	2.81
2036	33,131	1,750	0	0.00	0	0	0	34,881	10,550	8.62	2.61
2037	33,131	1,777	0	0.00	0	0	0	34,907	9,798	8.63	2.42
2038	33,131	1,803	0	0.00	0	0	0	34,934	9,099	8.63	2.25
2039	33,131	1,830	0	0.00	0	0	0	34,961	8,451	8.64	2.09
2040	33,131	1,858	0	0.00	0	0	0	34,988	7,848	8.65	1.94
2041	0	1,886	0	0.00	0	0	0	1,886	392	0.47	0.10
2042	0	1,914	0	0.00	0	0	0	1,914	370	0.47	0.09
2043	0	1,943	0	0.00	0	0	0	1,943	348	0.48	0.09
2044	0	1,972	0	0.00	0	0	0	1,972	328	0.49	0.08
2045	0	2,001	0	0.00	0	0	0	2,001	309	0.49	0.08
							Net Levelized Busbar Cost (c/kWh)				**7.90**
							Net Levelized Cost ($000s)				**31,983**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-29 Busbar Cost Model for Option 21CW at a 23.1 Percent Capacity Factor

Option 22GW: 100 MW - Solar PV SAT - Gillette, WY											
25-Year Busbar Cost Calculation											
Plant Input Data					Economic Input Data					Rate	Escalation
EPC Capital Cost ($1000)				$ 112,400	First Year Fixed O&M Cost ($/kW-yr)					7.0	1.5%
Other Owner Costs, except Esc & IDC				$ 22,500	First Year Variable O&M ($/MWh)					0.00	1.5%
Total Capital Cost (with Esc & IDC)				$ 134,900	Fuel Rate ($/MMBTU)					0.00	
Total Net Output, Avg Ambient Cond. (kW)				100,000	Construction Period (months)						
Capacity Factor				21.7%	Present Worth Discount Rate					7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				0	Levelized Fixed Charge Rate (25 yr)					12.5%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	16,916	700	0	0.00	0	0	0	17,616	16,348	9.27	8.60
2022	16,916	711	0	0.00	0	0	0	17,627	15,180	9.27	7.99
2023	16,916	721	0	0.00	0	0	0	17,638	14,095	9.28	7.41
2024	16,916	732	0	0.00	0	0	0	17,648	13,088	9.28	6.89
2025	16,916	743	0	0.00	0	0	0	17,659	12,153	9.29	6.39
2026	16,916	754	0	0.00	0	0	0	17,671	11,285	9.30	5.94
2027	16,916	765	0	0.00	0	0	0	17,682	10,479	9.30	5.51
2028	16,916	777	0	0.00	0	0	0	17,693	9,731	9.31	5.12
2029	16,916	789	0	0.00	0	0	0	17,705	9,036	9.31	4.75
2030	16,916	800	0	0.00	0	0	0	17,717	8,391	9.32	4.41
2031	16,916	812	0	0.00	0	0	0	17,729	7,792	9.33	4.10
2032	16,916	825	0	0.00	0	0	0	17,741	7,236	9.33	3.81
2033	16,916	837	0	0.00	0	0	0	17,753	6,719	9.34	3.53
2034	16,916	849	0	0.00	0	0	0	17,766	6,240	9.35	3.28
2035	16,916	862	0	0.00	0	0	0	17,779	5,795	9.35	3.05
2036	16,916	875	0	0.00	0	0	0	17,792	5,381	9.36	2.83
2037	16,916	888	0	0.00	0	0	0	17,805	4,998	9.37	2.63
2038	16,916	902	0	0.00	0	0	0	17,818	4,641	9.37	2.44
2039	16,916	915	0	0.00	0	0	0	17,832	4,310	9.38	2.27
2040	16,916	929	0	0.00	0	0	0	17,845	4,003	9.39	2.11
2041	0	943	0	0.00	0	0	0	943	196	0.50	0.10
2042	0	957	0	0.00	0	0	0	957	185	0.50	0.10
2043	0	971	0	0.00	0	0	0	971	174	0.51	0.09
2044	0	986	0	0.00	0	0	0	986	164	0.52	0.09
2045	0	1,001	0	0.00	0	0	0	1,001	154	0.53	0.08
							Net Levelized Busbar Cost (c/kWh)				**8.58**
							Net Levelized Cost ($000s)				**16,314**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-30 Busbar Cost Model for Option 22GW at a 21.7 Percent Capacity Factor

Option 22SD: 100 MW - Solar PV SAT - Hot Springs, SD

25-Year Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 112,400	First Year Fixed O&M Cost ($/kW-yr)	7.0	1.5%
Other Owner Costs, except Esc & IDC	$ 22,500	First Year Variable O&M ($/MWh)	0.00	1.5%
Total Capital Cost (with Esc & IDC)	$ 134,900	Fuel Rate ($/MMBTU)	0.00	
Total Net Output, Avg Ambient Cond. (kW)	100,000	Construction Period (months)		
Capacity Factor	24.6%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	0	Levelized Fixed Charge Rate (25 yr)	12.5%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	16,916	700	0	0.00	0	0	0	17,616	16,348	8.17	7.59
2022	16,916	711	0	0.00	0	0	0	17,627	15,180	8.18	7.04
2023	16,916	721	0	0.00	0	0	0	17,638	14,095	8.18	6.54
2024	16,916	732	0	0.00	0	0	0	17,648	13,088	8.19	6.07
2025	16,916	743	0	0.00	0	0	0	17,659	12,153	8.19	5.64
2026	16,916	754	0	0.00	0	0	0	17,671	11,285	8.20	5.24
2027	16,916	765	0	0.00	0	0	0	17,682	10,479	8.21	4.86
2028	16,916	777	0	0.00	0	0	0	17,693	9,731	8.21	4.52
2029	16,916	789	0	0.00	0	0	0	17,705	9,036	8.22	4.19
2030	16,916	800	0	0.00	0	0	0	17,717	8,391	8.22	3.89
2031	16,916	812	0	0.00	0	0	0	17,729	7,792	8.23	3.62
2032	16,916	825	0	0.00	0	0	0	17,741	7,236	8.23	3.36
2033	16,916	837	0	0.00	0	0	0	17,753	6,719	8.24	3.12
2034	16,916	849	0	0.00	0	0	0	17,766	6,240	8.24	2.90
2035	16,916	862	0	0.00	0	0	0	17,779	5,795	8.25	2.69
2036	16,916	875	0	0.00	0	0	0	17,792	5,381	8.26	2.50
2037	16,916	888	0	0.00	0	0	0	17,805	4,998	8.26	2.32
2038	16,916	902	0	0.00	0	0	0	17,818	4,641	8.27	2.15
2039	16,916	915	0	0.00	0	0	0	17,832	4,310	8.27	2.00
2040	16,916	929	0	0.00	0	0	0	17,845	4,003	8.28	1.86
2041	0	943	0	0.00	0	0	0	943	196	0.44	0.09
2042	0	957	0	0.00	0	0	0	957	185	0.44	0.09
2043	0	971	0	0.00	0	0	0	971	174	0.45	0.08
2044	0	986	0	0.00	0	0	0	986	164	0.46	0.08
2045	0	1,001	0	0.00	0	0	0	1,001	154	0.46	0.07
								Net Levelized Busbar Cost (c/kWh)			**7.57**
								Net Levelized Cost ($000s)			**16,314**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-31 Busbar Cost Model for Option 22SD at a 24.6 Percent Capacity Factor

Option 22CW: 100 MW - Solar PV SAT - Cheyenne, WY											
25-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 112,400		First Year Fixed O&M Cost ($/kW-yr)				7.0	1.5%
Other Owner Costs, except Esc & IDC				$ 22,500		First Year Variable O&M ($/MWh)				0.00	1.5%
Total Capital Cost (with Esc & IDC)				$ 134,900		Fuel Rate ($/MMBTU)				0.00	
Total Net Output, Avg Ambient Cond. (kW)				100,000		Construction Period (months)					
Capacity Factor				23.1%		Present Worth Discount Rate				7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				0		Levelized Fixed Charge Rate (25 yr)				12.5%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	16,916	700	0	0.00	0	0	0	17,616	16,348	8.71	8.08
2022	16,916	711	0	0.00	0	0	0	17,627	15,180	8.71	7.50
2023	16,916	721	0	0.00	0	0	0	17,638	14,095	8.72	6.97
2024	16,916	732	0	0.00	0	0	0	17,648	13,088	8.72	6.47
2025	16,916	743	0	0.00	0	0	0	17,659	12,153	8.73	6.01
2026	16,916	754	0	0.00	0	0	0	17,671	11,285	8.73	5.58
2027	16,916	765	0	0.00	0	0	0	17,682	10,479	8.74	5.18
2028	16,916	777	0	0.00	0	0	0	17,693	9,731	8.74	4.81
2029	16,916	789	0	0.00	0	0	0	17,705	9,036	8.75	4.47
2030	16,916	800	0	0.00	0	0	0	17,717	8,391	8.76	4.15
2031	16,916	812	0	0.00	0	0	0	17,729	7,792	8.76	3.85
2032	16,916	825	0	0.00	0	0	0	17,741	7,236	8.77	3.58
2033	16,916	837	0	0.00	0	0	0	17,753	6,719	8.77	3.32
2034	16,916	849	0	0.00	0	0	0	17,766	6,240	8.78	3.08
2035	16,916	862	0	0.00	0	0	0	17,779	5,795	8.79	2.86
2036	16,916	875	0	0.00	0	0	0	17,792	5,381	8.79	2.66
2037	16,916	888	0	0.00	0	0	0	17,805	4,998	8.80	2.47
2038	16,916	902	0	0.00	0	0	0	17,818	4,641	8.81	2.29
2039	16,916	915	0	0.00	0	0	0	17,832	4,310	8.81	2.13
2040	16,916	929	0	0.00	0	0	0	17,845	4,003	8.82	1.98
2041	0	943	0	0.00	0	0	0	943	196	0.47	0.10
2042	0	957	0	0.00	0	0	0	957	185	0.47	0.09
2043	0	971	0	0.00	0	0	0	971	174	0.48	0.09
2044	0	986	0	0.00	0	0	0	986	164	0.49	0.08
2045	0	1,001	0	0.00	0	0	0	1,001	154	0.49	0.08
							Net Levelized Busbar Cost (c/kWh)				**8.06**
							Net Levelized Cost ($000s)				**16,314**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-32 Busbar Cost Model for Option 22CW at a 23.1 Percent Capacity Factor

Option 23GW: 50 MW - Solar PV SAT - Gillette, WY											
25-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 58,200		First Year Fixed O&M Cost ($/kW-yr)				7.0	1.5%
Other Owner Costs, except Esc & IDC				$ 11,650		First Year Variable O&M ($/MWh)				0.00	1.5%
Total Capital Cost (with Esc & IDC)				$ 69,850		Fuel Rate ($/MMBTU)				0.00	
Total Net Output, Avg Ambient Cond. (kW)				50,000		Construction Period (months)					
Capacity Factor				21.7%		Present Worth Discount Rate				7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				0		Levelized Fixed Charge Rate (25 yr)				12.5%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	8,759	350	0	0.00	0	0	0	9,109	8,453	9.58	8.89
2022	8,759	355	0	0.00	0	0	0	9,114	7,849	9.59	8.26
2023	8,759	361	0	0.00	0	0	0	9,120	7,288	9.60	7.67
2024	8,759	366	0	0.00	0	0	0	9,125	6,767	9.60	7.12
2025	8,759	371	0	0.00	0	0	0	9,131	6,284	9.61	6.61
2026	8,759	377	0	0.00	0	0	0	9,136	5,835	9.61	6.14
2027	8,759	383	0	0.00	0	0	0	9,142	5,418	9.62	5.70
2028	8,759	388	0	0.00	0	0	0	9,148	5,031	9.62	5.29
2029	8,759	394	0	0.00	0	0	0	9,153	4,672	9.63	4.92
2030	8,759	400	0	0.00	0	0	0	9,159	4,338	9.64	4.56
2031	8,759	406	0	0.00	0	0	0	9,165	4,028	9.64	4.24
2032	8,759	412	0	0.00	0	0	0	9,171	3,741	9.65	3.94
2033	8,759	418	0	0.00	0	0	0	9,178	3,474	9.66	3.65
2034	8,759	425	0	0.00	0	0	0	9,184	3,226	9.66	3.39
2035	8,759	431	0	0.00	0	0	0	9,190	2,995	9.67	3.15
2036	8,759	438	0	0.00	0	0	0	9,197	2,782	9.68	2.93
2037	8,759	444	0	0.00	0	0	0	9,203	2,583	9.68	2.72
2038	8,759	451	0	0.00	0	0	0	9,210	2,399	9.69	2.52
2039	8,759	458	0	0.00	0	0	0	9,217	2,228	9.70	2.34
2040	8,759	464	0	0.00	0	0	0	9,224	2,069	9.70	2.18
2041	0	471	0	0.00	0	0	0	471	98	0.50	0.10
2042	0	478	0	0.00	0	0	0	478	92	0.50	0.10
2043	0	486	0	0.00	0	0	0	486	87	0.51	0.09
2044	0	493	0	0.00	0	0	0	493	82	0.52	0.09
2045	0	500	0	0.00	0	0	0	500	77	0.53	0.08
							Net Levelized Busbar Cost (c/kWh)				**8.87**
							Net Levelized Cost ($000s)				**8,433**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-33 Busbar Cost Model for Option 23GW at a 21.7 Percent Capacity Factor

Option 23SD: 50 MW - Solar PV SAT - Hot Springs, SD				
25-Year Busbar Cost Calculation				
Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 58,200	First Year Fixed O&M Cost ($/kW-yr)	7.0	1.5%
Other Owner Costs, except Esc & IDC	$ 11,650	First Year Variable O&M ($/MWh)	0.00	1.5%
Total Capital Cost (with Esc & IDC)	$ 69,850	Fuel Rate ($/MMBTU)	0.00	
Total Net Output, Avg Ambient Cond. (kW)	50,000	Construction Period (months)		
Capacity Factor	24.6%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	0	Levelized Fixed Charge Rate (25 yr)	12.5%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	8,759	350	0	0.00	0	0	0	9,109	8,453	8.45	7.85
2022	8,759	355	0	0.00	0	0	0	9,114	7,849	8.46	7.28
2023	8,759	361	0	0.00	0	0	0	9,120	7,288	8.46	6.76
2024	8,759	366	0	0.00	0	0	0	9,125	6,767	8.47	6.28
2025	8,759	371	0	0.00	0	0	0	9,131	6,284	8.47	5.83
2026	8,759	377	0	0.00	0	0	0	9,136	5,835	8.48	5.42
2027	8,759	383	0	0.00	0	0	0	9,142	5,418	8.48	5.03
2028	8,759	388	0	0.00	0	0	0	9,148	5,031	8.49	4.67
2029	8,759	394	0	0.00	0	0	0	9,153	4,672	8.50	4.34
2030	8,759	400	0	0.00	0	0	0	9,159	4,338	8.50	4.03
2031	8,759	406	0	0.00	0	0	0	9,165	4,028	8.51	3.74
2032	8,759	412	0	0.00	0	0	0	9,171	3,741	8.51	3.47
2033	8,759	418	0	0.00	0	0	0	9,178	3,474	8.52	3.22
2034	8,759	425	0	0.00	0	0	0	9,184	3,226	8.52	2.99
2035	8,759	431	0	0.00	0	0	0	9,190	2,995	8.53	2.78
2036	8,759	438	0	0.00	0	0	0	9,197	2,782	8.54	2.58
2037	8,759	444	0	0.00	0	0	0	9,203	2,583	8.54	2.40
2038	8,759	451	0	0.00	0	0	0	9,210	2,399	8.55	2.23
2039	8,759	458	0	0.00	0	0	0	9,217	2,228	8.55	2.07
2040	8,759	464	0	0.00	0	0	0	9,224	2,069	8.56	1.92
2041	0	471	0	0.00	0	0	0	471	98	0.44	0.09
2042	0	478	0	0.00	0	0	0	478	92	0.44	0.09
2043	0	486	0	0.00	0	0	0	486	87	0.45	0.08
2044	0	493	0	0.00	0	0	0	493	82	0.46	0.08
2045	0	500	0	0.00	0	0	0	500	77	0.46	0.07
							Net Levelized Busbar Cost (c/kWh)				**7.83**
							Net Levelized Cost ($000s)				**8,433**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-34 Busbar Cost Model for Option 23SD at a 24.6 Percent Capacity Factor

Option 23CW: 50 MW - Solar PV SAT - Cheyenne, WY

25-Year Busbar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 58,200	First Year Fixed O&M Cost ($/kW-yr)	7.0	1.5%
Other Owner Costs, except Esc & IDC	$ 11,650	First Year Variable O&M ($/MWh)	0.00	1.5%
Total Capital Cost (with Esc & IDC)	$ 69,850	Fuel Rate ($/MMBTU)	0.00	
Total Net Output, Avg Ambient Cond. (kW)	50,000	Construction Period (months)		
Capacity Factor	23.1%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	0	Levelized Fixed Charge Rate (25 yr)	12.5%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	8,759	350	0	0.00	0	0	0	9,109	8,453	9.00	8.35
2022	8,759	355	0	0.00	0	0	0	9,114	7,849	9.01	7.76
2023	8,759	361	0	0.00	0	0	0	9,120	7,288	9.01	7.20
2024	8,759	366	0	0.00	0	0	0	9,125	6,767	9.02	6.69
2025	8,759	371	0	0.00	0	0	0	9,131	6,284	9.02	6.21
2026	8,759	377	0	0.00	0	0	0	9,136	5,835	9.03	5.77
2027	8,759	383	0	0.00	0	0	0	9,142	5,418	9.04	5.35
2028	8,759	388	0	0.00	0	0	0	9,148	5,031	9.04	4.97
2029	8,759	394	0	0.00	0	0	0	9,153	4,672	9.05	4.62
2030	8,759	400	0	0.00	0	0	0	9,159	4,338	9.05	4.29
2031	8,759	406	0	0.00	0	0	0	9,165	4,028	9.06	3.98
2032	8,759	412	0	0.00	0	0	0	9,171	3,741	9.06	3.70
2033	8,759	418	0	0.00	0	0	0	9,178	3,474	9.07	3.43
2034	8,759	425	0	0.00	0	0	0	9,184	3,226	9.08	3.19
2035	8,759	431	0	0.00	0	0	0	9,190	2,995	9.08	2.96
2036	8,759	438	0	0.00	0	0	0	9,197	2,782	9.09	2.75
2037	8,759	444	0	0.00	0	0	0	9,203	2,583	9.10	2.55
2038	8,759	451	0	0.00	0	0	0	9,210	2,399	9.10	2.37
2039	8,759	458	0	0.00	0	0	0	9,217	2,228	9.11	2.20
2040	8,759	464	0	0.00	0	0	0	9,224	2,069	9.12	2.04
2041	0	471	0	0.00	0	0	0	471	98	0.47	0.10
2042	0	478	0	0.00	0	0	0	478	92	0.47	0.09
2043	0	486	0	0.00	0	0	0	486	87	0.48	0.09
2044	0	493	0	0.00	0	0	0	493	82	0.49	0.08
2045	0	500	0	0.00	0	0	0	500	77	0.49	0.08
							Net Levelized Busbar Cost (c/kWh)				**8.33**
							Net Levelized Cost ($000s)				**8,433**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-35 Busbar Cost Model for Option 23CW at a 23.1 Percent Capacity Factor

Option 24CW: 200 MW - Wind - Cheyenne, WY											
25-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 225,000		First Year Fixed O&M Cost ($/kW-yr)				30.0	1.5%
Other Owner Costs, except Esc & IDC				$ 45,000		First Year Variable O&M ($/MWh)				0.00	1.5%
Total Capital Cost (with Esc & IDC)				$ 270,200		Fuel Rat ($/MMBTU)				0.00	
Total Net Output, Avg Ambient Cond. (kW)				200,000		Construction Period (months)					
Capacity Factor				48.06%		Present Worth Discount Rate				7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				0		Levelized Fixed Charge Rate (25 yr)				12.5%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	33,883	6,000	0	0.00	0	0	0	39,883	37,011	4.74	4.40
2022	33,883	6,090	0	0.00	0	0	0	39,973	34,423	4.75	4.09
2023	33,883	6,181	0	0.00	0	0	0	40,064	32,017	4.76	3.80
2024	33,883	6,274	0	0.00	0	0	0	40,157	29,781	4.77	3.54
2025	33,883	6,368	0	0.00	0	0	0	40,251	27,701	4.78	3.29
2026	33,883	6,464	0	0.00	0	0	0	40,347	25,767	4.79	3.06
2027	33,883	6,561	0	0.00	0	0	0	40,444	23,969	4.80	2.85
2028	33,883	6,659	0	0.00	0	0	0	40,542	22,297	4.81	2.65
2029	33,883	6,759	0	0.00	0	0	0	40,642	20,742	4.83	2.46
2030	33,883	6,860	0	0.00	0	0	0	40,743	19,297	4.84	2.29
2031	33,883	6,963	0	0.00	0	0	0	40,846	17,952	4.85	2.13
2032	33,883	7,068	0	0.00	0	0	0	40,951	16,702	4.86	1.98
2033	33,883	7,174	0	0.00	0	0	0	41,057	15,539	4.88	1.85
2034	33,883	7,281	0	0.00	0	0	0	41,164	14,458	4.89	1.72
2035	33,883	7,391	0	0.00	0	0	0	41,274	13,453	4.90	1.60
2036	33,883	7,501	0	0.00	0	0	0	41,384	12,517	4.91	1.49
2037	33,883	7,614	0	0.00	0	0	0	41,497	11,648	4.93	1.38
2038	33,883	7,728	0	0.00	0	0	0	41,611	10,839	4.94	1.29
2039	33,883	7,844	0	0.00	0	0	0	41,727	10,086	4.96	1.20
2040	33,883	7,962	0	0.00	0	0	0	41,845	9,386	4.97	1.11
2041	0	8,081	0	0.00	0	0	0	8,081	1,682	0.96	0.20
2042	0	8,202	0	0.00	0	0	0	8,202	1,584	0.97	0.19
2043	0	8,325	0	0.00	0	0	0	8,325	1,492	0.99	0.18
2044	0	8,450	0	0.00	0	0	0	8,450	1,406	1.00	0.17
2045	0	8,577	0	0.00	0	0	0	8,577	1,324	1.02	0.16
						Net Levelized Busbar Cost (c/kWh)					**4.50**
						Net Levelized Cost ($000s)					**37,906**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-36 Busbar Cost Model for Option 24CW at a 48.06 Percent Capacity Factor

Option 24GW: 200 MW - Wind - Gillette, WY						
25-Year Busbar Cost Calculation						
Plant Input Data			Economic Input Data		Rate	Escalation
EPC Capital Cost ($1000)		$ 225,000	First Year Fixed O&M Cost ($/kW-yr)		30.0	1.5%
Other Owner Costs, except Esc & IDC		$ 45,000	First Year Variable O&M ($/MWh)		0.00	1.5%
Total Capital Cost (with Esc & IDC)		$ 270,200	Fuel Rate ($/MMBTU)		0.00	
Total Net Output, Avg Ambient Cond. (kW)		200,000	Construction Period (months)			
Capacity Factor		42.66%	Present Worth Discount Rate		7.8%	
Full Load Heat Rate, Btu/kWh (HHV)		0	Levelized Fixed Charge Rate (25 yr)		12.5%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	33,883	6,000	0	0.00	0	0	0	39,883	37,011	5.34	4.95
2022	33,883	6,090	0	0.00	0	0	0	39,973	34,423	5.35	4.61
2023	33,883	6,181	0	0.00	0	0	0	40,064	32,017	5.36	4.28
2024	33,883	6,274	0	0.00	0	0	0	40,157	29,781	5.37	3.98
2025	33,883	6,368	0	0.00	0	0	0	40,251	27,701	5.39	3.71
2026	33,883	6,464	0	0.00	0	0	0	40,347	25,767	5.40	3.45
2027	33,883	6,561	0	0.00	0	0	0	40,444	23,969	5.41	3.21
2028	33,883	6,659	0	0.00	0	0	0	40,542	22,297	5.42	2.98
2029	33,883	6,759	0	0.00	0	0	0	40,642	20,742	5.44	2.78
2030	33,883	6,860	0	0.00	0	0	0	40,743	19,297	5.45	2.58
2031	33,883	6,963	0	0.00	0	0	0	40,846	17,952	5.47	2.40
2032	33,883	7,068	0	0.00	0	0	0	40,951	16,702	5.48	2.23
2033	33,883	7,174	0	0.00	0	0	0	41,057	15,539	5.49	2.08
2034	33,883	7,281	0	0.00	0	0	0	41,164	14,458	5.51	1.93
2035	33,883	7,391	0	0.00	0	0	0	41,274	13,453	5.52	1.80
2036	33,883	7,501	0	0.00	0	0	0	41,384	12,517	5.54	1.67
2037	33,883	7,614	0	0.00	0	0	0	41,497	11,648	5.55	1.56
2038	33,883	7,728	0	0.00	0	0	0	41,611	10,839	5.57	1.45
2039	33,883	7,844	0	0.00	0	0	0	41,727	10,086	5.58	1.35
2040	33,883	7,962	0	0.00	0	0	0	41,845	9,386	5.60	1.26
2041	0	8,081	0	0.00	0	0	0	8,081	1,682	1.08	0.23
2042	0	8,202	0	0.00	0	0	0	8,202	1,584	1.10	0.21
2043	0	8,325	0	0.00	0	0	0	8,325	1,492	1.11	0.20
2044	0	8,450	0	0.00	0	0	0	8,450	1,406	1.13	0.19
2045	0	8,577	0	0.00	0	0	0	8,577	1,324	1.15	0.18
								Net Levelized Busbar Cost (c/kWh)			**5.07**
								Net Levelized Cost ($000s)			**37,906**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-37 Busbar Cost Model for Option 24GW at a 42.66 Percent Capacity Factor

Option 24DW: 200 MW - Wind - Douglas, WY											
25-Year Busbar Cost Calculation											
Plant Input Data					Economic Input Data					Rate	Escalation
EPC Capital Cost ($1000)				$ 225,000	First Year Fixed O&M Cost ($/kW-yr)					30.0	1.5%
Other Owner Costs, except Esc & IDC				$ 45,000	First Year Variable O&M ($/MWh)					0.00	1.5%
Total Capital Cost (with Esc & IDC)				$ 270,200	Fuel Rate ($/MMBTU)					0.00	
Total Net Output, Avg Ambient Cond. (kW)				200,000	Construction Period (months)						
Capacity Factor				45.42%	Present Worth Discount Rate					7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				0	Levelized Fixed Charge Rate (25 yr)					12.5%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	33,883	6,000	0	0.00	0	0	0	39,883	37,011	5.01	4.65
2022	33,883	6,090	0	0.00	0	0	0	39,973	34,423	5.02	4.33
2023	33,883	6,181	0	0.00	0	0	0	40,064	32,017	5.03	4.02
2024	33,883	6,274	0	0.00	0	0	0	40,157	29,781	5.05	3.74
2025	33,883	6,368	0	0.00	0	0	0	40,251	27,701	5.06	3.48
2026	33,883	6,464	0	0.00	0	0	0	40,347	25,767	5.07	3.24
2027	33,883	6,561	0	0.00	0	0	0	40,444	23,969	5.08	3.01
2028	33,883	6,659	0	0.00	0	0	0	40,542	22,297	5.09	2.80
2029	33,883	6,759	0	0.00	0	0	0	40,642	20,742	5.11	2.61
2030	33,883	6,860	0	0.00	0	0	0	40,743	19,297	5.12	2.42
2031	33,883	6,963	0	0.00	0	0	0	40,846	17,952	5.13	2.26
2032	33,883	7,068	0	0.00	0	0	0	40,951	16,702	5.15	2.10
2033	33,883	7,174	0	0.00	0	0	0	41,057	15,539	5.16	1.95
2034	33,883	7,281	0	0.00	0	0	0	41,164	14,458	5.17	1.82
2035	33,883	7,391	0	0.00	0	0	0	41,274	13,453	5.19	1.69
2036	33,883	7,501	0	0.00	0	0	0	41,384	12,517	5.20	1.57
2037	33,883	7,614	0	0.00	0	0	0	41,497	11,648	5.21	1.46
2038	33,883	7,728	0	0.00	0	0	0	41,611	10,839	5.23	1.36
2039	33,883	7,844	0	0.00	0	0	0	41,727	10,086	5.24	1.27
2040	33,883	7,962	0	0.00	0	0	0	41,845	9,386	5.26	1.18
2041	0	8,081	0	0.00	0	0	0	8,081	1,682	1.02	0.21
2042	0	8,202	0	0.00	0	0	0	8,202	1,584	1.03	0.20
2043	0	8,325	0	0.00	0	0	0	8,325	1,492	1.05	0.19
2044	0	8,450	0	0.00	0	0	0	8,450	1,406	1.06	0.18
2045	0	8,577	0	0.00	0	0	0	8,577	1,324	1.08	0.17
							Net Levelized Busbar Cost (c/kWh)				**4.76**
							Net Levelized Cost ($000s)				**37,906**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-38 Busbar Cost Model for Option 24DW at a 45.42 Percent Capacity Factor

Option 25CW: 100 MW - Wind - Cheyenne, WY

25-Year Busbar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 114,200	First Year Fixed O&M Cost ($/kW-yr)	32.0	1.5%
Other Owner Costs, except Esc & IDC	$ 22,800	First Year Variable O&M ($/MWh)	0.00	1.5%
Total Capital Cost (with Esc & IDC)	$ 137,100	Fuel Rate ($/MMBTU)	0.00	
Total Net Output, Avg Ambient Cond. (kW)	100,000	Construction Period (months)		
Capacity Factor	48.06%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	0	Levelized Fixed Charge Rate (25 yr)	12.5%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	17,192	3,200	0	0.00	0	0	0	20,392	18,924	4.84	4.49
2022	17,192	3,248	0	0.00	0	0	0	20,440	17,602	4.86	4.18
2023	17,192	3,297	0	0.00	0	0	0	20,489	16,374	4.87	3.89
2024	17,192	3,346	0	0.00	0	0	0	20,539	15,231	4.88	3.62
2025	17,192	3,396	0	0.00	0	0	0	20,589	14,169	4.89	3.37
2026	17,192	3,447	0	0.00	0	0	0	20,640	13,181	4.90	3.13
2027	17,192	3,499	0	0.00	0	0	0	20,691	12,263	4.91	2.91
2028	17,192	3,552	0	0.00	0	0	0	20,744	11,409	4.93	2.71
2029	17,192	3,605	0	0.00	0	0	0	20,797	10,614	4.94	2.52
2030	17,192	3,659	0	0.00	0	0	0	20,851	9,875	4.95	2.35
2031	17,192	3,714	0	0.00	0	0	0	20,906	9,188	4.97	2.18
2032	17,192	3,769	0	0.00	0	0	0	20,962	8,549	4.98	2.03
2033	17,192	3,826	0	0.00	0	0	0	21,018	7,955	4.99	1.89
2034	17,192	3,883	0	0.00	0	0	0	21,076	7,402	5.01	1.76
2035	17,192	3,942	0	0.00	0	0	0	21,134	6,888	5.02	1.64
2036	17,192	4,001	0	0.00	0	0	0	21,193	6,410	5.03	1.52
2037	17,192	4,061	0	0.00	0	0	0	21,253	5,965	5.05	1.42
2038	17,192	4,122	0	0.00	0	0	0	21,314	5,552	5.06	1.32
2039	17,192	4,183	0	0.00	0	0	0	21,376	5,167	5.08	1.23
2040	17,192	4,246	0	0.00	0	0	0	21,439	4,809	5.09	1.14
2041	0	4,310	0	0.00	0	0	0	4,310	897	1.02	0.21
2042	0	4,375	0	0.00	0	0	0	4,375	845	1.04	0.20
2043	0	4,440	0	0.00	0	0	0	4,440	796	1.05	0.19
2044	0	4,507	0	0.00	0	0	0	4,507	750	1.07	0.18
2045	0	4,574	0	0.00	0	0	0	4,574	706	1.09	0.17
								Net Levelized Busbar Cost (c/kWh)			**4.61**
								Net Levelized Cost ($000s)			**19,411**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-39 Busbar Cost Model for Option 25CW at a 48.06 Percent Capacity Factor

Option 25GW: 100 MW - Wind - Gillette, WY											
25-Year Busbar Cost Calculation											
Plant Input Data					Economic Input Data					Rate	Escalation
EPC Capital Cost ($1000)				$ 114,200	First Year Fixed O&M Cost ($/kW-yr)					32.0	1.5%
Other Owner Costs, except Esc & IDC				$ 22,800	First Year Variable O&M ($/MWh)					0.00	1.5%
Total Capital Cost (with Esc & IDC)				$ 137,100	Fuel Rate ($/MMBTU)					0.00	
Total Net Output, Avg Ambient Cond. (kW)				100,000	Construction Period (months)						
Capacity Factor				42.66%	Present Worth Discount Rate					7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				0	Levelized Fixed Charge Rate (25 yr)					12.5%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	17,192	3,200	0	0.00	0	0	0	20,392	18,924	5.46	5.06
2022	17,192	3,248	0	0.00	0	0	0	20,440	17,602	5.47	4.71
2023	17,192	3,297	0	0.00	0	0	0	20,489	16,374	5.48	4.38
2024	17,192	3,346	0	0.00	0	0	0	20,539	15,231	5.50	4.08
2025	17,192	3,396	0	0.00	0	0	0	20,589	14,169	5.51	3.79
2026	17,192	3,447	0	0.00	0	0	0	20,640	13,181	5.52	3.53
2027	17,192	3,499	0	0.00	0	0	0	20,691	12,263	5.54	3.28
2028	17,192	3,552	0	0.00	0	0	0	20,744	11,409	5.55	3.05
2029	17,192	3,605	0	0.00	0	0	0	20,797	10,614	5.57	2.84
2030	17,192	3,659	0	0.00	0	0	0	20,851	9,875	5.58	2.64
2031	17,192	3,714	0	0.00	0	0	0	20,906	9,188	5.59	2.46
2032	17,192	3,769	0	0.00	0	0	0	20,962	8,549	5.61	2.29
2033	17,192	3,826	0	0.00	0	0	0	21,018	7,955	5.62	2.13
2034	17,192	3,883	0	0.00	0	0	0	21,076	7,402	5.64	1.98
2035	17,192	3,942	0	0.00	0	0	0	21,134	6,888	5.66	1.84
2036	17,192	4,001	0	0.00	0	0	0	21,193	6,410	5.67	1.72
2037	17,192	4,061	0	0.00	0	0	0	21,253	5,965	5.69	1.60
2038	17,192	4,122	0	0.00	0	0	0	21,314	5,552	5.70	1.49
2039	17,192	4,183	0	0.00	0	0	0	21,376	5,167	5.72	1.38
2040	17,192	4,246	0	0.00	0	0	0	21,439	4,809	5.74	1.29
2041	0	4,310	0	0.00	0	0	0	4,310	897	1.15	0.24
2042	0	4,375	0	0.00	0	0	0	4,375	845	1.17	0.23
2043	0	4,440	0	0.00	0	0	0	4,440	796	1.19	0.21
2044	0	4,507	0	0.00	0	0	0	4,507	750	1.21	0.20
2045	0	4,574	0	0.00	0	0	0	4,574	706	1.22	0.19
							Net Levelized Busbar Cost (c/kWh)				**5.19**
							Net Levelized Cost ($000s)				**19,411**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-40 Busbar Cost Model for Option 25GW at a 42.66 Percent Capacity Factor

Option 25DW: 100 MW - Wind - Douglas, WY

25-Year Busbar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 114,200	First Year Fixed O&M Cost ($/kW-yr)	32.0	1.5%
Other Owner Costs, except Esc & IDC	$ 22,800	First Year Variable O&M ($/MWh)	0.00	1.5%
Total Capital Cost (with Esc & IDC)	$ 137,100	Fuel Rate ($/MMBTU)	0.00	
Total Net Output, Avg Ambient Cond. (kW)	100,000	Construction Period (months)		
Capacity Factor	45.42%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	0	Levelized Fixed Charge Rate (25 yr)	12.5%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	17,192	3,200	0	0.00	0	0	0	20,392	18,924	5.13	4.76
2022	17,192	3,248	0	0.00	0	0	0	20,440	17,602	5.14	4.42
2023	17,192	3,297	0	0.00	0	0	0	20,489	16,374	5.15	4.12
2024	17,192	3,346	0	0.00	0	0	0	20,539	15,231	5.16	3.83
2025	17,192	3,396	0	0.00	0	0	0	20,589	14,169	5.17	3.56
2026	17,192	3,447	0	0.00	0	0	0	20,640	13,181	5.19	3.31
2027	17,192	3,499	0	0.00	0	0	0	20,691	12,263	5.20	3.08
2028	17,192	3,552	0	0.00	0	0	0	20,744	11,409	5.21	2.87
2029	17,192	3,605	0	0.00	0	0	0	20,797	10,614	5.23	2.67
2030	17,192	3,659	0	0.00	0	0	0	20,851	9,875	5.24	2.48
2031	17,192	3,714	0	0.00	0	0	0	20,906	9,188	5.25	2.31
2032	17,192	3,769	0	0.00	0	0	0	20,962	8,549	5.27	2.15
2033	17,192	3,826	0	0.00	0	0	0	21,018	7,955	5.28	2.00
2034	17,192	3,883	0	0.00	0	0	0	21,076	7,402	5.30	1.86
2035	17,192	3,942	0	0.00	0	0	0	21,134	6,888	5.31	1.73
2036	17,192	4,001	0	0.00	0	0	0	21,193	6,410	5.33	1.61
2037	17,192	4,061	0	0.00	0	0	0	21,253	5,965	5.34	1.50
2038	17,192	4,122	0	0.00	0	0	0	21,314	5,552	5.36	1.40
2039	17,192	4,183	0	0.00	0	0	0	21,376	5,167	5.37	1.30
2040	17,192	4,246	0	0.00	0	0	0	21,439	4,809	5.39	1.21
2041	0	4,310	0	0.00	0	0	0	4,310	897	1.08	0.23
2042	0	4,375	0	0.00	0	0	0	4,375	845	1.10	0.21
2043	0	4,440	0	0.00	0	0	0	4,440	796	1.12	0.20
2044	0	4,507	0	0.00	0	0	0	4,507	750	1.13	0.19
2045	0	4,574	0	0.00	0	0	0	4,574	706	1.15	0.18
							Net Levelized Busbar Cost (c/kWh)				**4.88**
							Net Levelized Cost ($000s)				**19,411**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-41 Busbar Cost Model for Option 25DW at a 45.42 Percent Capacity Factor

Option 26CW: 50 MW - Wind - Cheyenne, WY												
25-Year Busbar Cost Calculation												
Plant Input Data						Economic Input Data					Rate	Escalation
EPC Capital Cost ($1000)				$ 57,200		First Year Fixed O&M Cost ($/kW-yr)					34.0	1.5%
Other Owner Costs, except Esc & IDC				$ 11,450		First Year Variable O&M ($/MWh)					0.00	1.5%
Total Capital Cost (with Esc & IDC)				$ 68,650		Fuel Rate ($/MMBTU)					0.00	
Total Net Output, Avg Ambient Cond. (kW)				50,000		Construction Period (months)						
Capacity Factor				48.06%		Present Worth Discount Rate					7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				0		Levelized Fixed Charge Rate (25 yr)					12.5%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)	
2021	8,609	1,700	0	0.00	0	0	0	10,309	9,566	4.90	4.54	
2022	8,609	1,726	0	0.00	0	0	0	10,334	8,899	4.91	4.23	
2023	8,609	1,751	0	0.00	0	0	0	10,360	8,279	4.92	3.93	
2024	8,609	1,778	0	0.00	0	0	0	10,386	7,703	4.93	3.66	
2025	8,609	1,804	0	0.00	0	0	0	10,413	7,166	4.95	3.40	
2026	8,609	1,831	0	0.00	0	0	0	10,440	6,667	4.96	3.17	
2027	8,609	1,859	0	0.00	0	0	0	10,468	6,204	4.97	2.95	
2028	8,609	1,887	0	0.00	0	0	0	10,495	5,772	4.99	2.74	
2029	8,609	1,915	0	0.00	0	0	0	10,524	5,371	5.00	2.55	
2030	8,609	1,944	0	0.00	0	0	0	10,552	4,998	5.01	2.37	
2031	8,609	1,973	0	0.00	0	0	0	10,582	4,651	5.03	2.21	
2032	8,609	2,003	0	0.00	0	0	0	10,611	4,328	5.04	2.06	
2033	8,609	2,033	0	0.00	0	0	0	10,641	4,028	5.06	1.91	
2034	8,609	2,063	0	0.00	0	0	0	10,672	3,748	5.07	1.78	
2035	8,609	2,094	0	0.00	0	0	0	10,703	3,488	5.08	1.66	
2036	8,609	2,125	0	0.00	0	0	0	10,734	3,247	5.10	1.54	
2037	8,609	2,157	0	0.00	0	0	0	10,766	3,022	5.11	1.44	
2038	8,609	2,190	0	0.00	0	0	0	10,798	2,813	5.13	1.34	
2039	8,609	2,222	0	0.00	0	0	0	10,831	2,618	5.15	1.24	
2040	8,609	2,256	0	0.00	0	0	0	10,865	2,437	5.16	1.16	
2041	0	2,290	0	0.00	0	0	0	2,290	477	1.09	0.23	
2042	0	2,324	0	0.00	0	0	0	2,324	449	1.10	0.21	
2043	0	2,359	0	0.00	0	0	0	2,359	423	1.12	0.20	
2044	0	2,394	0	0.00	0	0	0	2,394	398	1.14	0.19	
2045	0	2,430	0	0.00	0	0	0	2,430	375	1.15	0.18	
						Net Levelized Busbar Cost (c/kWh)					**4.67**	
						Net Levelized Cost ($000s)					**9,831**	
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.												

Figure A-42 Busbar Cost Model for Option 26CW at a 48.06 Percent Capacity Factor

Option 26GW: 50 MW - Wind - Gillette, WY											
25-Year Busbar Cost Calculation											
Plant Input Data					Economic Input Data				Rate	Escalation	
EPC Capital Cost ($1000)				$ 57,200	First Year Fixed O&M Cost ($/kW-yr)				34.0	1.5%	
Other Owner Costs, except Esc & IDC				$ 11,450	First Year Variable O&M ($/MWh)				0.00	1.5%	
Total Capital Cost (with Esc & IDC)				$ 68,650	Fuel Rate ($/MMBTU)				0.00		
Total Net Output, Avg Ambient Cond. (kW)				50,000	Construction Period (months)						
Capacity Factor				42.66%	Present Worth Discount Rate				7.8%		
Full Load Heat Rate, Btu/kWh (HHV)				0	Levelized Fixed Charge Rate (25 yr)				12.5%		
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	8,609	1,700	0	0.00	0	0	0	10,309	9,566	5.52	5.12
2022	8,609	1,726	0	0.00	0	0	0	10,334	8,899	5.53	4.76
2023	8,609	1,751	0	0.00	0	0	0	10,360	8,279	5.54	4.43
2024	8,609	1,778	0	0.00	0	0	0	10,386	7,703	5.56	4.12
2025	8,609	1,804	0	0.00	0	0	0	10,413	7,166	5.57	3.84
2026	8,609	1,831	0	0.00	0	0	0	10,440	6,667	5.59	3.57
2027	8,609	1,859	0	0.00	0	0	0	10,468	6,204	5.60	3.32
2028	8,609	1,887	0	0.00	0	0	0	10,495	5,772	5.62	3.09
2029	8,609	1,915	0	0.00	0	0	0	10,524	5,371	5.63	2.87
2030	8,609	1,944	0	0.00	0	0	0	10,552	4,998	5.65	2.67
2031	8,609	1,973	0	0.00	0	0	0	10,582	4,651	5.66	2.49
2032	8,609	2,003	0	0.00	0	0	0	10,611	4,328	5.68	2.32
2033	8,609	2,033	0	0.00	0	0	0	10,641	4,028	5.70	2.16
2034	8,609	2,063	0	0.00	0	0	0	10,672	3,748	5.71	2.01
2035	8,609	2,094	0	0.00	0	0	0	10,703	3,488	5.73	1.87
2036	8,609	2,125	0	0.00	0	0	0	10,734	3,247	5.74	1.74
2037	8,609	2,157	0	0.00	0	0	0	10,766	3,022	5.76	1.62
2038	8,609	2,190	0	0.00	0	0	0	10,798	2,813	5.78	1.51
2039	8,609	2,222	0	0.00	0	0	0	10,831	2,618	5.80	1.40
2040	8,609	2,256	0	0.00	0	0	0	10,865	2,437	5.81	1.30
2041	0	2,290	0	0.00	0	0	0	2,290	477	1.23	0.26
2042	0	2,324	0	0.00	0	0	0	2,324	449	1.24	0.24
2043	0	2,359	0	0.00	0	0	0	2,359	423	1.26	0.23
2044	0	2,394	0	0.00	0	0	0	2,394	398	1.28	0.21
2045	0	2,430	0	0.00	0	0	0	2,430	375	1.30	0.20
						Net Levelized Busbar Cost (c/kWh)					**5.26**
						Net Levelized Cost ($000s)					**9,831**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-43 Busbar Cost Model for Option 26GW at a 42.66 Percent Capacity Factor

Option 26DW: 50 MW - Wind - Douglas, WY											
25-Year Busbar Cost Calculation											
Plant Input Data				Economic Input Data					Rate	Escalation	
EPC Capital Cost ($1000)			$ 57,200	First Year Fixed O&M Cost ($/kW-yr)					34.0	1.5%	
Other Owner Costs, except Esc & IDC			$ 11,450	First Year Variable O&M ($/MWh)					0.00	1.5%	
Total Capital Cost (with Esc & IDC)			$ 68,650	Fuel Rate ($/MMBTU)					0.00		
Total Net Output, Avg Ambient Cond. (kW)			50,000	Construction Period (months)							
Capacity Factor			45.42%	Present Worth Discount Rate					7.8%		
Full Load Heat Rate, Btu/kWh (HHV)			0	Levelized Fixed Charge Rate (25 yr)					12.5%		

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	8,609	1,700	0	0.00	0	0	0	10,309	9,566	5.18	4.81
2022	8,609	1,726	0	0.00	0	0	0	10,334	8,899	5.19	4.47
2023	8,609	1,751	0	0.00	0	0	0	10,360	8,279	5.21	4.16
2024	8,609	1,778	0	0.00	0	0	0	10,386	7,703	5.22	3.87
2025	8,609	1,804	0	0.00	0	0	0	10,413	7,166	5.23	3.60
2026	8,609	1,831	0	0.00	0	0	0	10,440	6,667	5.25	3.35
2027	8,609	1,859	0	0.00	0	0	0	10,468	6,204	5.26	3.12
2028	8,609	1,887	0	0.00	0	0	0	10,495	5,772	5.28	2.90
2029	8,609	1,915	0	0.00	0	0	0	10,524	5,371	5.29	2.70
2030	8,609	1,944	0	0.00	0	0	0	10,552	4,998	5.30	2.51
2031	8,609	1,973	0	0.00	0	0	0	10,582	4,651	5.32	2.34
2032	8,609	2,003	0	0.00	0	0	0	10,611	4,328	5.33	2.18
2033	8,609	2,033	0	0.00	0	0	0	10,641	4,028	5.35	2.02
2034	8,609	2,063	0	0.00	0	0	0	10,672	3,748	5.36	1.88
2035	8,609	2,094	0	0.00	0	0	0	10,703	3,488	5.38	1.75
2036	8,609	2,125	0	0.00	0	0	0	10,734	3,247	5.40	1.63
2037	8,609	2,157	0	0.00	0	0	0	10,766	3,022	5.41	1.52
2038	8,609	2,190	0	0.00	0	0	0	10,798	2,813	5.43	1.41
2039	8,609	2,222	0	0.00	0	0	0	10,831	2,618	5.44	1.32
2040	8,609	2,256	0	0.00	0	0	0	10,865	2,437	5.46	1.23
2041	0	2,290	0	0.00	0	0	0	2,290	477	1.15	0.24
2042	0	2,324	0	0.00	0	0	0	2,324	449	1.17	0.23
2043	0	2,359	0	0.00	0	0	0	2,359	423	1.19	0.21
2044	0	2,394	0	0.00	0	0	0	2,394	398	1.20	0.20
2045	0	2,430	0	0.00	0	0	0	2,430	375	1.22	0.19
								Net Levelized Busbar Cost (c/kWh)			**4.94**
								Net Levelized Cost ($000s)			**9,831**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-44 Busbar Cost Model for Option 26DW at a 45.42 Percent Capacity Factor

Option 27W: Stand Alone 4-hour BESS - 10 MW in Wyoming					
20-Year Busbar Cost Calculation					
Plant Input Data		Economic Input Data		Rate	Escalation
EPC Capital Cost ($1000)	$ 19,102	First Year Fixed O&M Cost ($/kWh-yr)		7.5	1.5%
Other Owner Costs, except Esc & IDC	$ 2,122	1st Yr. Var. O&M Charging Cost, $/kWh		0.02	1.5%
Total Capital Cost (with Esc & IDC)	$ 21,225	Fuel Rate ($/MMBTU)		0.00	
kW of Output	10,000	Cycles per Day		1	
Hours of Full Output per Cycle	4	Present Worth Discount Rate		7.8%	
kWh Purchased/Cycle	44,444	Levelized Fixed Charge Rate (20 yr)		13.9%	

Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	2,955	0.202	300	269	0.00	0	0	3,523	3,270	24.13	22.39
2022	2,955	0.202	305	301	0.00	0	0	3,560	3,066	24.38	21.00
2023	2,955	0.202	309	340	0.00	0	0	3,603	2,879	24.68	19.72
2024	2,955	0.202	314	343	0.00	0	0	3,611	2,678	24.74	18.34
2025	2,955	0.202	318	340	0.00	0	0	3,613	2,487	24.75	17.03
2026	2,955	0.202	323	352	0.00	0	0	3,630	2,318	24.86	15.88
2027	2,955	0.202	328	363	0.00	0	0	3,645	2,160	24.97	14.80
2028	2,955	0.202	333	386	0.00	0	0	3,674	2,021	25.16	13.84
2029	2,955	0.202	338	384	0.00	0	0	3,676	1,876	25.18	12.85
2030	2,955	0.202	343	381	0.00	0	0	3,678	1,742	25.19	11.93
2031	2,955	0.202	348	396	0.00	0	0	3,699	1,626	25.34	11.14
2032	2,955	0.202	353	417	0.00	0	0	3,725	1,519	25.51	10.41
2033	2,955	0.202	359	432	0.00	0	0	3,745	1,417	25.65	9.71
2034	2,955	0.202	364	435	0.00	0	0	3,753	1,318	25.71	9.03
2035	2,955	0.202	370	435	0.00	0	0	3,759	1,225	25.75	8.39
2036	2,955	0.202	375	436	0.00	0	0	3,765	1,139	25.79	7.80
2037	2,955	0.202	381	461	0.00	0	0	3,796	1,066	26.00	7.30
2038	2,955	0.202	386	471	0.00	0	0	3,812	993	26.11	6.80
2039	2,955	0.202	392	485	0.00	0	0	3,832	926	26.25	6.34
2040	2,955	0.202	398	485	0.00	0	0	3,837	861	26.28	5.90
							Net Levelized Busbar Cost (c/kWh)				**25.07**
							Net Levelized Cost ($000s)				**3,660**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-45 Busbar Cost Model for Option 27W at One Cycle Per Day

Option 27SD: Stand Alone 4-hour BESS - 10 MW in South Dakota											
20-Year Busbar Cost Calculation											
Plant Input Data				Economic Input Data						Rate	Escalation
EPC Capital Cost ($1000)			$ 19,102	First Year Fixed O&M Cost ($/kWh-yr)						7.5	1.5%
Other Owner Costs, except Esc & IDC			$ 2,122	1st Yr. Var. O&M Charging Cost, $/kWh						0.03	1.5%
Total Capital Cost (with Esc & IDC)			$ 21,225	Fuel Rate ($/MMBTU)						0.00	
kW of Output			10,000	Cycles per Day						1	
Hours of Full Output per Cycle			4	Present Worth Discount Rate						7.8%	
kWh Purchased/Cycle			44,444	Levelized Fixed Charge Rate (20 yr)						13.9%	
Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	2,955	0.202	300	459	0.00	0	0	3,713	3,446	25.43	23.60
2022	2,955	0.202	305	450	0.00	0	0	3,709	3,194	25.41	21.88
2023	2,955	0.202	309	466	0.00	0	0	3,730	2,981	25.55	20.41
2024	2,955	0.202	314	470	0.00	0	0	3,738	2,772	25.60	18.99
2025	2,955	0.202	318	473	0.00	0	0	3,746	2,578	25.66	17.66
2026	2,955	0.202	323	477	0.00	0	0	3,755	2,398	25.72	16.42
2027	2,955	0.202	328	490	0.00	0	0	3,773	2,236	25.84	15.32
2028	2,955	0.202	333	499	0.00	0	0	3,787	2,083	25.94	14.26
2029	2,955	0.202	338	508	0.00	0	0	3,800	1,939	26.03	13.28
2030	2,955	0.202	343	504	0.00	0	0	3,802	1,801	26.04	12.33
2031	2,955	0.202	348	524	0.00	0	0	3,827	1,682	26.21	11.52
2032	2,955	0.202	353	538	0.00	0	0	3,846	1,569	26.34	10.74
2033	2,955	0.202	359	553	0.00	0	0	3,866	1,463	26.48	10.02
2034	2,955	0.202	364	561	0.00	0	0	3,880	1,363	26.57	9.33
2035	2,955	0.202	370	541	0.00	0	0	3,865	1,260	26.47	8.63
2036	2,955	0.202	375	531	0.00	0	0	3,860	1,168	26.44	8.00
2037	2,955	0.202	381	532	0.00	0	0	3,867	1,086	26.49	7.44
2038	2,955	0.202	386	526	0.00	0	0	3,867	1,007	26.49	6.90
2039	2,955	0.202	392	522	0.00	0	0	3,868	935	26.50	6.40
2040	2,955	0.202	398	574	0.00	0	0	3,926	881	26.89	6.03
						Net Levelized Busbar Cost (c/kWh)					**25.93**
						Net Levelized Cost ($000s)					**3,786**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-46 Busbar Cost Model for Option 27SD at One Cycle Per Day

Option 28W: Stand Alone 4-hour BESS - 30 MW in Wyoming											
20-Year Busbar Cost Calculation											
Plant Input Data					Economic Input Data					Rate	Escalation
EPC Capital Cost ($1000)			$ 52,833		First Year Fixed O&M Cost ($/kWh-yr)					7.5	1.5%
Other Owner Costs, except Esc & IDC			$ 5,870		1st Yr. Var. O&M Charging Cost, $/kWh					0.02	1.5%
Total Capital Cost (with Esc & IDC)			$ 58,703		Fuel Rate ($/MMBTU)					0.00	
kW of Output			30,000		Cycles per Day					1	
Hours of Full Output per Cycle			4		Present Worth Discount Rate					7.8%	
kWh Purchased/Cycle			133,333		Levelized Fixed Charge Rate (20 yr)					13.9%	
Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	8,171	0.187	900	806	0.00	0	0	9,878	9,167	22.55	20.93
2022	8,171	0.187	914	903	0.00	0	0	9,988	8,601	22.80	19.64
2023	8,171	0.187	927	1,019	0.00	0	0	10,117	8,085	23.10	18.46
2024	8,171	0.187	941	1,029	0.00	0	0	10,142	7,521	23.15	17.17
2025	8,171	0.187	955	1,021	0.00	0	0	10,148	6,984	23.17	15.94
2026	8,171	0.187	970	1,057	0.00	0	0	10,198	6,513	23.28	14.87
2027	8,171	0.187	984	1,088	0.00	0	0	10,244	6,071	23.39	13.86
2028	8,171	0.187	999	1,159	0.00	0	0	10,330	5,681	23.58	12.97
2029	8,171	0.187	1,014	1,151	0.00	0	0	10,336	5,275	23.60	12.04
2030	8,171	0.187	1,029	1,142	0.00	0	0	10,343	4,898	23.61	11.18
2031	8,171	0.187	1,044	1,189	0.00	0	0	10,405	4,573	23.76	10.44
2032	8,171	0.187	1,060	1,252	0.00	0	0	10,483	4,276	23.93	9.76
2033	8,171	0.187	1,076	1,295	0.00	0	0	10,543	3,990	24.07	9.11
2034	8,171	0.187	1,092	1,304	0.00	0	0	10,567	3,712	24.13	8.47
2035	8,171	0.187	1,109	1,306	0.00	0	0	10,586	3,450	24.17	7.88
2036	8,171	0.187	1,125	1,307	0.00	0	0	10,603	3,207	24.21	7.32
2037	8,171	0.187	1,142	1,383	0.00	0	0	10,697	3,002	24.42	6.85
2038	8,171	0.187	1,159	1,413	0.00	0	0	10,743	2,798	24.53	6.39
2039	8,171	0.187	1,177	1,456	0.00	0	0	10,804	2,612	24.67	5.96
2040	8,171	0.187	1,194	1,455	0.00	0	0	10,820	2,427	24.70	5.54
							Net Levelized Busbar Cost (c/kWh)				**23.49**
							Net Levelized Cost ($000s)				**10,288**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-47 Busbar Cost Model for Option 28W at One Cycle Per Day

Option 28SD: Stand Alone 4-hour BESS - 30 MW in South Dakota			
20-Year Busbar Cost Calculation			
Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 52,833	First Year Fixed O&M Cost ($/kWh-yr)	7.5	1.5%
Other Owner Costs, except Esc & IDC	$ 5,870	1st Yr. Var. O&M Charging Cost, $/kWh	0.03	1.5%
Total Capital Cost (with Esc & IDC)	$ 58,703	Fuel Rate ($/MMBTU)	0.00	
kW of Output	30,000	Cycles per Day	1	
Hours of Full Output per Cycle	4	Present Worth Discount Rate	7.8%	
kWh Purchased/Cycle	133,333	Levelized Fixed Charge Rate (20 yr)	13.9%	

Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	8,171	0.187	900	1,377	0.00	0	0	10,448	9,696	23.85	22.14
2022	8,171	0.187	914	1,351	0.00	0	0	10,436	8,987	23.83	20.52
2023	8,171	0.187	927	1,398	0.00	0	0	10,497	8,388	23.97	19.15
2024	8,171	0.187	941	1,410	0.00	0	0	10,522	7,803	24.02	17.82
2025	8,171	0.187	955	1,420	0.00	0	0	10,546	7,258	24.08	16.57
2026	8,171	0.187	970	1,431	0.00	0	0	10,572	6,751	24.14	15.41
2027	8,171	0.187	984	1,471	0.00	0	0	10,627	6,298	24.26	14.38
2028	8,171	0.187	999	1,498	0.00	0	0	10,668	5,867	24.36	13.40
2029	8,171	0.187	1,014	1,523	0.00	0	0	10,708	5,465	24.45	12.48
2030	8,171	0.187	1,029	1,512	0.00	0	0	10,713	5,074	24.46	11.58
2031	8,171	0.187	1,044	1,572	0.00	0	0	10,788	4,741	24.63	10.83
2032	8,171	0.187	1,060	1,615	0.00	0	0	10,846	4,424	24.76	10.10
2033	8,171	0.187	1,076	1,660	0.00	0	0	10,907	4,128	24.90	9.43
2034	8,171	0.187	1,092	1,684	0.00	0	0	10,948	3,845	24.99	8.78
2035	8,171	0.187	1,109	1,622	0.00	0	0	10,903	3,554	24.89	8.11
2036	8,171	0.187	1,125	1,592	0.00	0	0	10,889	3,294	24.86	7.52
2037	8,171	0.187	1,142	1,597	0.00	0	0	10,910	3,062	24.91	6.99
2038	8,171	0.187	1,159	1,578	0.00	0	0	10,909	2,841	24.91	6.49
2039	8,171	0.187	1,177	1,565	0.00	0	0	10,913	2,638	24.92	6.02
2040	8,171	0.187	1,194	1,721	0.00	0	0	11,087	2,487	25.31	5.68
							Net Levelized Busbar Cost (c/kWh)				**24.35**
							Net Levelized Cost ($000s)				**10,664**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-48 Busbar Cost Model for Option 28SD at One Cycle Per Day

Option 29W: Stand Alone 4-hour BESS - 100 MW in Wyoming											
20-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 161,098		First Year Fixed O&M Cost ($/kWh-yr)				7.5	1.5%
Other Owner Costs, except Esc & IDC				$ 17,900		1st Yr. Var. O&M Charging Cost, $/kWh				0.02	1.5%
Total Capital Cost (with Esc & IDC)				$ 178,997		Fuel Rate ($/MMBTU)				0.00	
kW of Output				100,000		Cycles per Day				1	
Hours of Full Output per Cycle				4		Present Worth Discount Rate				7.8%	
kWh Purchased/Cycle				444,444		Levelized Fixed Charge Rate (20 yr)				13.9%	
Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	24,916	0.171	3,000	2,688	0.00	0	0	30,604	28,401	20.96	19.45
2022	24,916	0.171	3,045	3,009	0.00	0	0	30,971	26,671	21.21	18.27
2023	24,916	0.171	3,091	3,395	0.00	0	0	31,402	25,095	21.51	17.19
2024	24,916	0.171	3,137	3,431	0.00	0	0	31,484	23,349	21.56	15.99
2025	24,916	0.171	3,184	3,403	0.00	0	0	31,504	21,681	21.58	14.85
2026	24,916	0.171	3,232	3,522	0.00	0	0	31,670	20,226	21.69	13.85
2027	24,916	0.171	3,280	3,627	0.00	0	0	31,824	18,860	21.80	12.92
2028	24,916	0.171	3,330	3,864	0.00	0	0	32,110	17,660	21.99	12.10
2029	24,916	0.171	3,379	3,837	0.00	0	0	32,132	16,399	22.01	11.23
2030	24,916	0.171	3,430	3,807	0.00	0	0	32,154	15,229	22.02	10.43
2031	24,916	0.171	3,482	3,965	0.00	0	0	32,363	14,224	22.17	9.74
2032	24,916	0.171	3,534	4,172	0.00	0	0	32,623	13,305	22.34	9.11
2033	24,916	0.171	3,587	4,317	0.00	0	0	32,820	12,422	22.48	8.51
2034	24,916	0.171	3,641	4,346	0.00	0	0	32,903	11,557	22.54	7.92
2035	24,916	0.171	3,695	4,352	0.00	0	0	32,964	10,744	22.58	7.36
2036	24,916	0.171	3,751	4,356	0.00	0	0	33,023	9,988	22.62	6.84
2037	24,916	0.171	3,807	4,610	0.00	0	0	33,334	9,356	22.83	6.41
2038	24,916	0.171	3,864	4,709	0.00	0	0	33,490	8,723	22.94	5.97
2039	24,916	0.171	3,922	4,854	0.00	0	0	33,692	8,144	23.08	5.58
2040	24,916	0.171	3,981	4,849	0.00	0	0	33,746	7,570	23.11	5.18
						Net Levelized Busbar Cost (c/kWh)					**21.90**
						Net Levelized Cost ($000s)					**31,973**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-49 Busbar Cost Model for Option 29W at One Cycle Per Day

Option 29SD: Stand Alone 4-hour BESS - 100 MW in South Dakota											
20-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 161,098		First Year Fixed O&M Cost ($/kWh-yr)				7.5	1.5%
Other Owner Costs, except Esc & IDC				$ 17,900		1st Yr. Var. O&M Charging Cost, $/kWh				0.03	1.5%
Total Capital Cost (with Esc & IDC)				$ 178,997		Fuel Rate ($/MMBTU)				0.00	
kW of Output				100,000		Cycles per Day				1	
Hours of Full Output per Cycle				4		Present Worth Discount Rate				7.8%	
kWh Purchased/Cycle				444,444		Levelized Fixed Charge Rate (20 yr)				13.9%	
Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	24,916	0.171	3,000	4,590	0.00	0	0	32,506	30,165	22.26	20.66
2022	24,916	0.171	3,045	4,504	0.00	0	0	32,466	27,958	22.24	19.15
2023	24,916	0.171	3,091	4,660	0.00	0	0	32,668	26,106	22.38	17.88
2024	24,916	0.171	3,137	4,699	0.00	0	0	32,752	24,289	22.43	16.64
2025	24,916	0.171	3,184	4,732	0.00	0	0	32,833	22,595	22.49	15.48
2026	24,916	0.171	3,232	4,769	0.00	0	0	32,917	21,022	22.55	14.40
2027	24,916	0.171	3,280	4,903	0.00	0	0	33,100	19,617	22.67	13.44
2028	24,916	0.171	3,330	4,992	0.00	0	0	33,238	18,280	22.77	12.52
2029	24,916	0.171	3,379	5,076	0.00	0	0	33,372	17,032	22.86	11.67
2030	24,916	0.171	3,430	5,041	0.00	0	0	33,388	15,813	22.87	10.83
2031	24,916	0.171	3,482	5,240	0.00	0	0	33,638	14,784	23.04	10.13
2032	24,916	0.171	3,534	5,382	0.00	0	0	33,832	13,799	23.17	9.45
2033	24,916	0.171	3,587	5,532	0.00	0	0	34,035	12,882	23.31	8.82
2034	24,916	0.171	3,641	5,613	0.00	0	0	34,170	12,002	23.40	8.22
2035	24,916	0.171	3,695	5,408	0.00	0	0	34,020	11,088	23.30	7.59
2036	24,916	0.171	3,751	5,307	0.00	0	0	33,974	10,276	23.27	7.04
2037	24,916	0.171	3,807	5,322	0.00	0	0	34,045	9,556	23.32	6.55
2038	24,916	0.171	3,864	5,260	0.00	0	0	34,040	8,867	23.32	6.07
2039	24,916	0.171	3,922	5,217	0.00	0	0	34,055	8,232	23.33	5.64
2040	24,916	0.171	3,981	5,736	0.00	0	0	34,633	7,769	23.72	5.32
						Net Levelized Busbar Cost (c/kWh)					**22.76**
						Net Levelized Cost ($000s)					**33,226**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-50 Busbar Cost Model for Option 29SD at One Cycle Per Day

Option 30W: Stand Alone 4-hour BESS - 200 MW in Wyoming												
20-Year Busbar Cost Calculation												
Plant Input Data						Economic Input Data					Rate	Escalation
EPC Capital Cost ($1000)				$ 306,085		First Year Fixed O&M Cost ($/kWh-yr)					7.5	1.5%
Other Owner Costs, except Esc & IDC				$ 34,009		1st Yr. Var. O&M Charging Cost, $/kWh					0.02	1.5%
Total Capital Cost (with Esc & IDC)				$ 340,095		Fuel Rate ($/MMBTU)					0.00	
kW of Output				200,000		Cycles per Day					1	
Hours of Full Output per Cycle				4		Present Worth Discount Rate					7.8%	
kWh Purchased/Cycle				888,889		Levelized Fixed Charge Rate (20 yr)					13.9%	
Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)	
2021	47,341	0.162	6,000	5,376	0.00	0	0	58,717	54,489	20.11	18.66	
2022	47,341	0.162	6,090	6,018	0.00	0	0	59,450	51,196	20.36	17.53	
2023	47,341	0.162	6,181	6,791	0.00	0	0	60,313	48,199	20.66	16.51	
2024	47,341	0.162	6,274	6,862	0.00	0	0	60,477	44,850	20.71	15.36	
2025	47,341	0.162	6,368	6,807	0.00	0	0	60,516	41,647	20.72	14.26	
2026	47,341	0.162	6,464	7,044	0.00	0	0	60,849	38,860	20.84	13.31	
2027	47,341	0.162	6,561	7,255	0.00	0	0	61,156	36,244	20.94	12.41	
2028	47,341	0.162	6,659	7,728	0.00	0	0	61,729	33,949	21.14	11.63	
2029	47,341	0.162	6,759	7,673	0.00	0	0	61,773	31,527	21.16	10.80	
2030	47,341	0.162	6,860	7,615	0.00	0	0	61,816	29,277	21.17	10.03	
2031	47,341	0.162	6,963	7,929	0.00	0	0	62,234	27,352	21.31	9.37	
2032	47,341	0.162	7,068	8,345	0.00	0	0	62,754	25,595	21.49	8.77	
2033	47,341	0.162	7,174	8,633	0.00	0	0	63,148	23,901	21.63	8.19	
2034	47,341	0.162	7,281	8,692	0.00	0	0	63,314	22,238	21.68	7.62	
2035	47,341	0.162	7,391	8,705	0.00	0	0	63,437	20,676	21.72	7.08	
2036	47,341	0.162	7,501	8,711	0.00	0	0	63,554	19,223	21.77	6.58	
2037	47,341	0.162	7,614	9,221	0.00	0	0	64,176	18,013	21.98	6.17	
2038	47,341	0.162	7,728	9,419	0.00	0	0	64,488	16,797	22.08	5.75	
2039	47,341	0.162	7,844	9,707	0.00	0	0	64,893	15,686	22.22	5.37	
2040	47,341	0.162	7,962	9,698	0.00	0	0	65,001	14,580	22.26	4.99	
						Net Levelized Busbar Cost (c/kWh)					**21.05**	
						Net Levelized Cost ($000s)					**61,455**	
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.												

Figure A-51 Busbar Cost Model for Option 30W at One Cycle Per Day

Option 30SD: Stand Alone 4-hour BESS - 200 MW in South Dakota											
20-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 306,085		First Year Fixed O&M Cost ($/kWh-yr)				7.5	1.5%
Other Owner Costs, except Esc & IDC				$ 34,009		1st Yr. Var. O&M Charging Cost, $/kWh				0.03	1.5%
Total Capital Cost (with Esc & IDC)				$ 340,095		Fuel Rate ($/MMBTU)				0.00	
kW of Output				200,000		Cycles per Day				1	
Hours of Full Output per Cycle				4		Present Worth Discount Rate				7.8%	
kWh Purchased/Cycle				888,889		Levelized Fixed Charge Rate (20 yr)				13.9%	
Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	47,341	0.162	6,000	9,179	0.00	0	0	62,521	58,018	21.41	19.87
2022	47,341	0.162	6,090	9,008	0.00	0	0	62,439	53,770	21.38	18.41
2023	47,341	0.162	6,181	9,321	0.00	0	0	62,843	50,221	21.52	17.20
2024	47,341	0.162	6,274	9,398	0.00	0	0	63,013	46,731	21.58	16.00
2025	47,341	0.162	6,368	9,464	0.00	0	0	63,173	43,476	21.63	14.89
2026	47,341	0.162	6,464	9,538	0.00	0	0	63,343	40,453	21.69	13.85
2027	47,341	0.162	6,561	9,807	0.00	0	0	63,709	37,757	21.82	12.93
2028	47,341	0.162	6,659	9,984	0.00	0	0	63,985	35,190	21.91	12.05
2029	47,341	0.162	6,759	10,152	0.00	0	0	64,252	32,792	22.00	11.23
2030	47,341	0.162	6,860	10,083	0.00	0	0	64,284	30,446	22.02	10.43
2031	47,341	0.162	6,963	10,480	0.00	0	0	64,784	28,473	22.19	9.75
2032	47,341	0.162	7,068	10,764	0.00	0	0	65,173	26,581	22.32	9.10
2033	47,341	0.162	7,174	11,064	0.00	0	0	65,579	24,821	22.46	8.50
2034	47,341	0.162	7,281	11,226	0.00	0	0	65,849	23,128	22.55	7.92
2035	47,341	0.162	7,391	10,817	0.00	0	0	65,548	21,365	22.45	7.32
2036	47,341	0.162	7,501	10,615	0.00	0	0	65,457	19,799	22.42	6.78
2037	47,341	0.162	7,614	10,644	0.00	0	0	65,599	18,413	22.47	6.31
2038	47,341	0.162	7,728	10,519	0.00	0	0	65,589	17,084	22.46	5.85
2039	47,341	0.162	7,844	10,433	0.00	0	0	65,618	15,861	22.47	5.43
2040	47,341	0.162	7,962	11,472	0.00	0	0	66,775	14,978	22.87	5.13
						Net Levelized Busbar Cost (c/kWh)					**21.90**
						Net Levelized Cost ($000s)					**63,961**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-52 Busbar Cost Model for Option 30SD at One Cycle Per Day

Option 31: 100MW Biofuel Plant											
25-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 408,000		First Year Fixed O&M Cost ($/kW-yr)				125.0	1.5%
Other Owner Costs, except Esc & IDC				$ 81,600		First Year Variable O&M ($/MWh)				4.80	1.5%
Total Capital Cost (with Esc & IDC)				$ 489,600		Fuel Rate ($/MMBTU)				3.13	1.5%
Total Net Output, Avg Ambient Cond. (kW)				100,000		Construction Period (months)					
Capacity Factor				90.0%		Present Worth Discount Rate				7.8%	
Full Load Heat Rate, Btu/kWh (HHV)				13,700		Levelized Fixed Charge Rate (25 yr)				13.9%	
Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	68,152	12,500	3,784	3.13	33,753	0	0	118,190	109,679	14.99	13.91
2022	68,152	12,688	3,841	3.17	34,260	0	0	118,941	102,427	15.09	12.99
2023	68,152	12,878	3,899	3.22	34,774	0	0	119,702	95,660	15.18	12.13
2024	68,152	13,071	3,957	3.27	35,295	0	0	120,476	89,345	15.28	11.33
2025	68,152	13,267	4,017	3.32	35,825	0	0	121,261	83,451	15.38	10.58
2026	68,152	13,466	4,077	3.37	36,362	0	0	122,057	77,950	15.48	9.89
2027	68,152	13,668	4,138	3.42	36,907	0	0	122,866	72,816	15.58	9.24
2028	68,152	13,873	4,200	3.47	37,461	0	0	123,686	68,024	15.69	8.63
2029	68,152	14,081	4,263	3.52	38,023	0	0	124,519	63,550	15.79	8.06
2030	68,152	14,292	4,327	3.57	38,593	0	0	125,365	59,375	15.90	7.53
2031	68,152	14,507	4,392	3.63	39,172	0	0	126,223	55,476	16.01	7.04
2032	68,152	14,724	4,458	3.68	39,760	0	0	127,094	51,836	16.12	6.57
2033	68,152	14,945	4,525	3.74	40,356	0	0	127,978	48,438	16.23	6.14
2034	68,152	15,169	4,592	3.79	40,961	0	0	128,876	45,265	16.35	5.74
2035	68,152	15,397	4,661	3.85	41,576	0	0	129,787	42,302	16.46	5.37
2036	68,152	15,628	4,731	3.91	42,200	0	0	130,711	39,536	16.58	5.01
2037	68,152	15,862	4,802	3.97	42,833	0	0	131,649	36,952	16.70	4.69
2038	68,152	16,100	4,874	4.03	43,475	0	0	132,602	34,539	16.82	4.38
2039	68,152	16,342	4,947	4.09	44,127	0	0	133,569	32,286	16.94	4.10
2040	68,152	16,587	5,022	4.15	44,789	0	0	134,550	30,181	17.07	3.83
2041	0	16,836	5,097	4.21	45,461	0	0	67,394	14,028	8.55	1.78
2042	0	17,088	5,173	4.27	46,143	0	0	68,404	13,213	8.68	1.68
2043	0	17,345	5,251	4.34	46,835	0	0	69,430	12,446	8.81	1.58
2044	0	17,605	5,330	4.40	47,537	0	0	70,472	11,723	8.94	1.49
2045	0	17,869	5,410	4.47	48,251	0	0	71,529	11,042	9.07	1.40
							Net Levelized Busbar Cost (c/kWh)				**15.15**
							Net Levelized Cost ($000s)				**119,437**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-53 Busbar Cost Model for Option 31 at a 90 Percent Capacity Factor

Option 32: 40 MW - Geo-thermal Plant				
25-Year Busbar Cost Calculation				
Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 285,840	First Year Fixed O&M Cost ($/kW-yr)	200.0	1.5%
Other Owner Costs, except Esc & IDC	$ 57,160	First Year Variable O&M ($/MWh)	0.00	1.5%
Total Capital Cost (with Esc & IDC)	$ 343,040	Fuel Rate ($/MMBTU)	0.00	
Total Net Output, Avg Ambient Cond. (kW)	40,000	Construction Period (months)		
Capacity Factor	90.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	0	Levelized Fixed Charge Rate (25 yr)	12.5%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	43,017	8,000	0	0.00	0	0	0	51,017	47,343	16.18	15.01
2022	43,017	8,120	0	0.00	0	0	0	51,137	44,037	16.22	13.96
2023	43,017	8,242	0	0.00	0	0	0	51,259	40,964	16.25	12.99
2024	43,017	8,365	0	0.00	0	0	0	51,383	38,105	16.29	12.08
2025	43,017	8,491	0	0.00	0	0	0	51,508	35,448	16.33	11.24
2026	43,017	8,618	0	0.00	0	0	0	51,635	32,976	16.37	10.46
2027	43,017	8,748	0	0.00	0	0	0	51,765	30,678	16.41	9.73
2028	43,017	8,879	0	0.00	0	0	0	51,896	28,541	16.46	9.05
2029	43,017	9,012	0	0.00	0	0	0	52,029	26,554	16.50	8.42
2030	43,017	9,147	0	0.00	0	0	0	52,164	24,706	16.54	7.83
2031	43,017	9,284	0	0.00	0	0	0	52,302	22,987	16.58	7.29
2032	43,017	9,424	0	0.00	0	0	0	52,441	21,388	16.63	6.78
2033	43,017	9,565	0	0.00	0	0	0	52,582	19,902	16.67	6.31
2034	43,017	9,708	0	0.00	0	0	0	52,726	18,519	16.72	5.87
2035	43,017	9,854	0	0.00	0	0	0	52,871	17,233	16.77	5.46
2036	43,017	10,002	0	0.00	0	0	0	53,019	16,037	16.81	5.09
2037	43,017	10,152	0	0.00	0	0	0	53,169	14,924	16.86	4.73
2038	43,017	10,304	0	0.00	0	0	0	53,321	13,889	16.91	4.40
2039	43,017	10,459	0	0.00	0	0	0	53,476	12,926	16.96	4.10
2040	43,017	10,616	0	0.00	0	0	0	53,633	12,030	17.01	3.81
2041	0	10,775	0	0.00	0	0	0	10,775	2,243	3.42	0.71
2042	0	10,936	0	0.00	0	0	0	10,936	2,113	3.47	0.67
2043	0	11,101	0	0.00	0	0	0	11,101	1,990	3.52	0.63
2044	0	11,267	0	0.00	0	0	0	11,267	1,874	3.57	0.59
2045	0	11,436	0	0.00	0	0	0	11,436	1,765	3.63	0.56
								Net Levelized Busbar Cost (c/kWh)			**15.40**
								Net Levelized Cost ($000s)			**48,560**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-54 Busbar Cost Model for Option 32 at a 90 Percent Capacity Factor

Option 33: 100 MW - Small Scale Modular Reactor

25-Year Busbar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 378,200	First Year Fixed O&M Cost ($/kW-yr)	100.0	1.5%
Other Owner Costs, except Esc & IDC	$ 115,600	First Year Variable O&M ($/MWh)	9.00	1.5%
Total Capital Cost (with Esc & IDC)	$ 493,800	Fuel Rate ($/MMBTU)	0.00	
Total Net Output, Avg Ambient Cond. (kW)	100,000	Construction Period (months)		
Capacity Factor	90.0%	Present Worth Discount Rate	7.8%	
Full Load Heat Rate, Btu/kWh (HHV)	0	Levelized Fixed Charge Rate (25 yr)	14.4%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	71,157	10,000	7,096	0.00	0	0	0	88,252	81,897	11.19	10.39
2022	71,157	10,150	7,202	0.00	0	0	0	88,509	76,220	11.23	9.67
2023	71,157	10,302	7,310	0.00	0	0	0	88,769	70,939	11.26	9.00
2024	71,157	10,457	7,420	0.00	0	0	0	89,033	66,027	11.29	8.37
2025	71,157	10,614	7,531	0.00	0	0	0	89,301	61,457	11.33	7.80
2026	71,157	10,773	7,644	0.00	0	0	0	89,573	57,205	11.36	7.26
2027	71,157	10,934	7,759	0.00	0	0	0	89,850	53,249	11.40	6.75
2028	71,157	11,098	7,875	0.00	0	0	0	90,130	49,569	11.43	6.29
2029	71,157	11,265	7,993	0.00	0	0	0	90,415	46,145	11.47	5.85
2030	71,157	11,434	8,113	0.00	0	0	0	90,704	42,958	11.50	5.45
2031	71,157	11,605	8,235	0.00	0	0	0	90,997	39,994	11.54	5.07
2032	71,157	11,779	8,358	0.00	0	0	0	91,294	37,235	11.58	4.72
2033	71,157	11,956	8,484	0.00	0	0	0	91,596	34,668	11.62	4.40
2034	71,157	12,136	8,611	0.00	0	0	0	91,903	32,279	11.66	4.09
2035	71,157	12,318	8,740	0.00	0	0	0	92,214	30,056	11.70	3.81
2036	71,157	12,502	8,871	0.00	0	0	0	92,530	27,987	11.74	3.55
2037	71,157	12,690	9,004	0.00	0	0	0	92,851	26,062	11.78	3.31
2038	71,157	12,880	9,139	0.00	0	0	0	93,176	24,270	11.82	3.08
2039	71,157	13,073	9,276	0.00	0	0	0	93,506	22,602	11.86	2.87
2040	71,157	13,270	9,416	0.00	0	0	0	93,842	21,050	11.90	2.67
2041	0	13,469	9,557	0.00	0	0	0	23,025	4,793	2.92	0.61
2042	0	13,671	9,700	0.00	0	0	0	23,371	4,514	2.96	0.57
2043	0	13,876	9,846	0.00	0	0	0	23,721	4,252	3.01	0.54
2044	0	14,084	9,993	0.00	0	0	0	24,077	4,005	3.05	0.51
2045	0	14,295	10,143	0.00	0	0	0	24,438	3,773	3.10	0.48
							Net Levelized Busbar Cost (c/kWh)				**10.75**
							Net Levelized Cost ($000s)				**84,719**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-55 Busbar Cost Model for Option 33 at a 90 Percent Capacity Factor

Option 34A: Add 30 min BESS to LM6000 - 137 MW											
20-Year Busbar Cost Calculation											
Plant Input Data						Economic Input Data				Rate	Escalation
EPC Capital Cost ($1000)				$ 37,165		First Year Fixed O&M Cost ($/kWh-yr)				7.5	1.5%
Other Owner Costs, except Esc & IDC				$ 4,129		1st Yr. Var. O&M Charging Cost, $/kWh				0.02	1.5%
Total Capital Cost (with Esc & IDC)				$ 41,294		Fuel Rate ($/MMBTU)				0.00	
kW of Output				137,000		Cycles per Day				1	
Hours of Full Output per Cycle				0.5		Present Worth Discount Rate				7.8%	
kWh Purchased/Cycle				76,111		Levelized Fixed Charge Rate (20 yr)				13.9%	
Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	5,748	0.230	514	460	0.00	0	0	6,722	6,238	26.89	24.95
2022	5,748	0.230	521	515	0.00	0	0	6,785	5,843	27.14	23.37
2023	5,748	0.230	529	581	0.00	0	0	6,859	5,481	27.43	21.92
2024	5,748	0.230	537	588	0.00	0	0	6,873	5,097	27.49	20.39
2025	5,748	0.230	545	583	0.00	0	0	6,876	4,732	27.50	18.93
2026	5,748	0.230	553	603	0.00	0	0	6,905	4,410	27.62	17.64
2027	5,748	0.230	562	621	0.00	0	0	6,931	4,108	27.72	16.43
2028	5,748	0.230	570	662	0.00	0	0	6,980	3,839	27.92	15.35
2029	5,748	0.230	579	657	0.00	0	0	6,984	3,564	27.93	14.26
2030	5,748	0.230	587	652	0.00	0	0	6,988	3,309	27.95	13.24
2031	5,748	0.230	596	679	0.00	0	0	7,023	3,087	28.09	12.35
2032	5,748	0.230	605	715	0.00	0	0	7,068	2,883	28.27	11.53
2033	5,748	0.230	614	739	0.00	0	0	7,102	2,688	28.40	10.75
2034	5,748	0.230	623	744	0.00	0	0	7,116	2,499	28.46	10.00
2035	5,748	0.230	633	745	0.00	0	0	7,126	2,323	28.50	9.29
2036	5,748	0.230	642	746	0.00	0	0	7,136	2,159	28.54	8.63
2037	5,748	0.230	652	790	0.00	0	0	7,190	2,018	28.76	8.07
2038	5,748	0.230	662	806	0.00	0	0	7,216	1,880	28.86	7.52
2039	5,748	0.230	672	831	0.00	0	0	7,251	1,753	29.00	7.01
2040	5,748	0.230	682	830	0.00	0	0	7,260	1,629	29.04	6.51
							Net Levelized Busbar Cost (c/kWh)				**27.82**
							Net Levelized Cost ($000s)				**6,957**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-56 Busbar Cost Model for Option 34A at One Cycle Per Day

Option 34B: Add 30 min BESS to LM6000 - 100 MW											
20-Year Busbar Cost Calculation											
Plant Input Data					Economic Input Data					Rate	Escalation
EPC Capital Cost ($1000)			$ 27,767		First Year Fixed O&M Cost ($/kWh-yr)					7.5	1.5%
Other Owner Costs, except Esc & IDC			$ 3,085		1st Yr. Var. O&M Charging Cost, $/kWh					0.02	1.5%
Total Capital Cost (with Esc & IDC)			$ 30,852		Fuel Rate ($/MMBTU)					0.00	
kW of Output			100,000		Cycles per Day					1	
Hours of Full Output per Cycle			0.5		Present Worth Discount Rate					7.8%	
kWh Purchased/Cycle			55,556		Levelized Fixed Charge Rate (20 yr)					13.9%	
Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	4,295	0.235	375	336	0.00	0	0	5,006	4,645	27.43	25.45
2022	4,295	0.235	381	376	0.00	0	0	5,051	4,350	27.68	23.84
2023	4,295	0.235	386	424	0.00	0	0	5,105	4,080	27.97	22.36
2024	4,295	0.235	392	429	0.00	0	0	5,116	3,794	28.03	20.79
2025	4,295	0.235	398	425	0.00	0	0	5,118	3,522	28.04	19.30
2026	4,295	0.235	404	440	0.00	0	0	5,139	3,282	28.16	17.98
2027	4,295	0.235	410	453	0.00	0	0	5,158	3,057	28.26	16.75
2028	4,295	0.235	416	483	0.00	0	0	5,194	2,856	28.46	15.65
2029	4,295	0.235	422	480	0.00	0	0	5,197	2,652	28.47	14.53
2030	4,295	0.235	429	476	0.00	0	0	5,199	2,462	28.49	13.49
2031	4,295	0.235	435	496	0.00	0	0	5,225	2,297	28.63	12.58
2032	4,295	0.235	442	522	0.00	0	0	5,258	2,144	28.81	11.75
2033	4,295	0.235	448	540	0.00	0	0	5,283	1,999	28.95	10.96
2034	4,295	0.235	455	543	0.00	0	0	5,293	1,859	29.00	10.19
2035	4,295	0.235	462	544	0.00	0	0	5,301	1,728	29.04	9.47
2036	4,295	0.235	469	544	0.00	0	0	5,308	1,605	29.08	8.80
2037	4,295	0.235	476	576	0.00	0	0	5,347	1,501	29.30	8.22
2038	4,295	0.235	483	589	0.00	0	0	5,366	1,398	29.40	7.66
2039	4,295	0.235	490	607	0.00	0	0	5,392	1,303	29.54	7.14
2040	4,295	0.235	498	606	0.00	0	0	5,398	1,211	29.58	6.64
							Net Levelized Busbar Cost (c/kWh)				**28.37**
							Net Levelized Cost ($000s)				**5,177**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-57 Busbar Cost Model for Option 34B at One Cycle Per Day

Option 34C: Add 30 min BESS to LM6000* - 100 MW

20-Year Busbar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 27,767	First Year Fixed O&M Cost ($/kWh-yr)	7.5	1.5%
Other Owner Costs, except Esc & IDC	$ 3,085	1st Yr. Var. O&M Charging Cost, $/kWh	0.02	1.5%
Total Capital Cost (with Esc & IDC)	$ 30,852	Fuel Rate ($/MMBTU)	0.00	
kW of Output	100,000	Cycles per Day	1	
Hours of Full Output per Cycle	0.5	Present Worth Discount Rate	7.8%	
kWh Purchased/Cycle	55,556	Levelized Fixed Charge Rate (20 yr)	13.9%	

Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	4,295	0.235	375	336	0.00	0	0	5,006	4,645	27.43	25.45
2022	4,295	0.235	381	376	0.00	0	0	5,051	4,350	27.68	23.84
2023	4,295	0.235	386	424	0.00	0	0	5,105	4,080	27.97	22.36
2024	4,295	0.235	392	429	0.00	0	0	5,116	3,794	28.03	20.79
2025	4,295	0.235	398	425	0.00	0	0	5,118	3,522	28.04	19.30
2026	4,295	0.235	404	440	0.00	0	0	5,139	3,282	28.16	17.98
2027	4,295	0.235	410	453	0.00	0	0	5,158	3,057	28.26	16.75
2028	4,295	0.235	416	483	0.00	0	0	5,194	2,856	28.46	15.65
2029	4,295	0.235	422	480	0.00	0	0	5,197	2,652	28.47	14.53
2030	4,295	0.235	429	476	0.00	0	0	5,199	2,462	28.49	13.49
2031	4,295	0.235	435	496	0.00	0	0	5,225	2,297	28.63	12.58
2032	4,295	0.235	442	522	0.00	0	0	5,258	2,144	28.81	11.75
2033	4,295	0.235	448	540	0.00	0	0	5,283	1,999	28.95	10.96
2034	4,295	0.235	455	543	0.00	0	0	5,293	1,859	29.00	10.19
2035	4,295	0.235	462	544	0.00	0	0	5,301	1,728	29.04	9.47
2036	4,295	0.235	469	544	0.00	0	0	5,308	1,605	29.08	8.80
2037	4,295	0.235	476	576	0.00	0	0	5,347	1,501	29.30	8.22
2038	4,295	0.235	483	589	0.00	0	0	5,366	1,398	29.40	7.66
2039	4,295	0.235	490	607	0.00	0	0	5,392	1,303	29.54	7.14
2040	4,295	0.235	498	606	0.00	0	0	5,398	1,211	29.58	6.64
							Net Levelized Busbar Cost (c/kWh)				**28.37**
							Net Levelized Cost ($000s)				**5,177**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-58 Busbar Cost Model for Option 34C at One Cycle Per Day

Option 34D: Add 30 min BESS to LM6000 - 56 MW				
20-Year Busbar Cost Calculation				
Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1000)	$ 16,231	First Year Fixed O&M Cost ($/kWh-yr)	7.5	1.5%
Other Owner Costs, except Esc & IDC	$ 1,803	1st Yr. Var. O&M Charging Cost, $/kWh	0.02	1.5%
Total Capital Cost (with Esc & IDC)	$ 18,035	Fuel Rate ($/MMBTU)	0.00	
kW of Output	56,000	Cycles per Day	1	
Hours of Full Output per Cycle	0.5	Present Worth Discount Rate	7.8%	
kWh Purchased/Cycle	31,111	Levelized Fixed Charge Rate (20 yr)	13.9%	

Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	2,510	0.246	210	188	0.00	0	0	2,909	2,699	28.46	26.41
2022	2,510	0.246	213	211	0.00	0	0	2,934	2,527	28.71	24.72
2023	2,510	0.246	216	238	0.00	0	0	2,964	2,369	29.01	23.18
2024	2,510	0.246	220	240	0.00	0	0	2,970	2,203	29.06	21.55
2025	2,510	0.246	223	238	0.00	0	0	2,972	2,045	29.08	20.01
2026	2,510	0.246	226	247	0.00	0	0	2,983	1,905	29.19	18.64
2027	2,510	0.246	230	254	0.00	0	0	2,994	1,774	29.29	17.36
2028	2,510	0.246	233	270	0.00	0	0	3,014	1,658	29.49	16.22
2029	2,510	0.246	237	269	0.00	0	0	3,016	1,539	29.51	15.06
2030	2,510	0.246	240	267	0.00	0	0	3,017	1,429	29.52	13.98
2031	2,510	0.246	244	278	0.00	0	0	3,032	1,332	29.66	13.04
2032	2,510	0.246	247	292	0.00	0	0	3,050	1,244	29.84	12.17
2033	2,510	0.246	251	302	0.00	0	0	3,064	1,160	29.98	11.35
2034	2,510	0.246	255	304	0.00	0	0	3,069	1,078	30.03	10.55
2035	2,510	0.246	259	305	0.00	0	0	3,074	1,002	30.08	9.80
2036	2,510	0.246	263	305	0.00	0	0	3,078	931	30.12	9.11
2037	2,510	0.246	266	323	0.00	0	0	3,100	870	30.33	8.51
2038	2,510	0.246	270	330	0.00	0	0	3,111	810	30.44	7.93
2039	2,510	0.246	275	340	0.00	0	0	3,125	755	30.57	7.39
2040	2,510	0.246	279	339	0.00	0	0	3,128	702	30.61	6.87
							Net Levelized Busbar Cost (c/kWh)				**29.40**
							Net Levelized Cost ($000s)				**3,004**

Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.

Figure A-59 Busbar Cost Model for Option 34D at One Cycle Per Day

Option 34E-W: Add 30 min BESS to LM6000 - 40 MW in Wyoming											
20-Year Busbar Cost Calculation											
Plant Input Data				Economic Input Data						Rate	Escalation
EPC Capital Cost ($1000)			$ 11,886	First Year Fixed O&M Cost ($/kWh-yr)						7.5	1.5%
Other Owner Costs, except Esc & IDC			$ 1,321	1st Yr. Var. O&M Charging Cost, $/kWh						0.02	1.5%
Total Capital Cost (with Esc & IDC)			$ 13,207	Fuel Rate ($/MMBTU)						0.00	
kW of Output			40,000	Cycles per Day						1	
Hours of Full Output per Cycle			0.5	Present Worth Discount Rate						7.8%	
kWh Purchased/Cycle			22,222	Levelized Fixed Charge Rate (20 yr)						13.9%	
Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	1,838	0.252	150	134	0.00	0	0	2,123	1,970	29.08	26.98
2022	1,838	0.252	152	150	0.00	0	0	2,141	1,844	29.33	25.26
2023	1,838	0.252	155	170	0.00	0	0	2,163	1,728	29.63	23.68
2024	1,838	0.252	157	172	0.00	0	0	2,167	1,607	29.68	22.01
2025	1,838	0.252	159	170	0.00	0	0	2,168	1,492	29.69	20.44
2026	1,838	0.252	162	176	0.00	0	0	2,176	1,390	29.81	19.04
2027	1,838	0.252	164	181	0.00	0	0	2,184	1,294	29.91	17.73
2028	1,838	0.252	166	193	0.00	0	0	2,198	1,209	30.11	16.56
2029	1,838	0.252	169	192	0.00	0	0	2,199	1,122	30.13	15.38
2030	1,838	0.252	172	190	0.00	0	0	2,200	1,042	30.14	14.27
2031	1,838	0.252	174	198	0.00	0	0	2,211	972	30.28	13.31
2032	1,838	0.252	177	209	0.00	0	0	2,224	907	30.46	12.42
2033	1,838	0.252	179	216	0.00	0	0	2,234	845	30.60	11.58
2034	1,838	0.252	182	217	0.00	0	0	2,238	786	30.65	10.77
2035	1,838	0.252	185	218	0.00	0	0	2,241	730	30.70	10.00
2036	1,838	0.252	188	218	0.00	0	0	2,244	679	30.74	9.30
2037	1,838	0.252	190	231	0.00	0	0	2,259	634	30.95	8.69
2038	1,838	0.252	193	235	0.00	0	0	2,267	590	31.06	8.09
2039	1,838	0.252	196	243	0.00	0	0	2,277	550	31.19	7.54
2040	1,838	0.252	199	242	0.00	0	0	2,280	511	31.23	7.01
							Net Levelized Busbar Cost (c/kWh)				**30.02**
							Net Levelized Cost ($000s)				**2,191**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-60 Busbar Cost Model for Option 34E-W at One Cycle Per Day

Option 34E-SD: Add 30 min BESS to LM6000 - 40 MW in South Dakota											
20-Year Busbar Cost Calculation											
Plant Input Data					Economic Input Data					Rate	Escalation
EPC Capital Cost ($1000)				$ 11,886	First Year Fixed O&M Cost ($/kWh-yr)					7.5	1.5%
Other Owner Costs, except Esc & IDC				$ 1,321	1st Yr. Var. O&M Charging Cost, $/kWh					0.03	1.5%
Total Capital Cost (with Esc & IDC)				$ 13,207	Fuel Rate ($/MMBTU)					0.00	
kW of Output				40,000	Cycles per Day					1	
Hours of Full Output per Cycle				0.5	Present Worth Discount Rate					7.8%	
kWh Purchased/Cycle				22,222	Levelized Fixed Charge Rate (20 yr)					13.9%	
Year	Annual Capital Cost ($ 1,000)	Capital Cost ($/kWh)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MMBTU)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Busbar Cost (c/kWh)	Net PW Cost (c/kWh)
2021	1,838	0.252	150	229	0.00	0	0	2,218	2,058	30.38	28.19
2022	1,838	0.252	152	225	0.00	0	0	2,216	1,908	30.35	26.14
2023	1,838	0.252	155	233	0.00	0	0	2,226	1,779	30.49	24.37
2024	1,838	0.252	157	235	0.00	0	0	2,230	1,654	30.55	22.66
2025	1,838	0.252	159	237	0.00	0	0	2,234	1,538	30.60	21.06
2026	1,838	0.252	162	238	0.00	0	0	2,238	1,430	30.66	19.58
2027	1,838	0.252	164	245	0.00	0	0	2,248	1,332	30.79	18.25
2028	1,838	0.252	166	250	0.00	0	0	2,254	1,240	30.88	16.98
2029	1,838	0.252	169	254	0.00	0	0	2,261	1,154	30.97	15.81
2030	1,838	0.252	172	252	0.00	0	0	2,262	1,071	30.99	14.68
2031	1,838	0.252	174	262	0.00	0	0	2,274	1,000	31.16	13.69
2032	1,838	0.252	177	269	0.00	0	0	2,284	932	31.29	12.76
2033	1,838	0.252	179	277	0.00	0	0	2,294	868	31.43	11.90
2034	1,838	0.252	182	281	0.00	0	0	2,301	808	31.52	11.07
2035	1,838	0.252	185	270	0.00	0	0	2,294	748	31.42	10.24
2036	1,838	0.252	188	265	0.00	0	0	2,291	693	31.39	9.49
2037	1,838	0.252	190	266	0.00	0	0	2,295	644	31.44	8.82
2038	1,838	0.252	193	263	0.00	0	0	2,295	598	31.43	8.19
2039	1,838	0.252	196	261	0.00	0	0	2,295	555	31.44	7.60
2040	1,838	0.252	199	287	0.00	0	0	2,324	521	31.84	7.14
							Net Levelized Busbar Cost (c/kWh)				**30.87**
							Net Levelized Cost ($000s)				**2,254**
Note: Owner's costs include AFUDC, startup costs, financing costs, linear facility costs outside the fence, and other costs not traditionally included in EPC costs.											

Figure A-61 Busbar Cost Model for Option 34E-SD at One Cycle Per Day

E. NEIL SIMPSON UNIT II POWER PLANT STUDIES

This appendix contains three studies conducted on Neil Simpson Unit II:

- Coal to Natural Gas Conversion Evaluation
- Life Assessment Report Update
- Decommissioning and Demolition Report

COAL TO NATURAL GAS CONVERSION EVALUATION

This study developed the conceptual design characteristics and cost for converting the coal-fired Neil Simpson Unit II plant to a 100 percent natural gas-fired boiler.

Conversion eliminates purchasing coal, coal handling and coal firing equipment, circulating dry scrubber and associated equipment, and the equipment, display, water use, and wastewater discharge treatment for ash handling. Removing this equipment results in much lower auxiliary power consumption.

In contrast, conversion requires installing new gas supply piping, metering, and regulation equipment as well as equipment associated with natural gas burners and electric high energy spark igniters. With little to no ash, conversion virtually eliminates cleaning the air heaters, boilers, precipitators, and dust control equipment.

Natural gas burners generate lower CO_2 emissions—1,100 pounds per MWh per unit—while maximizing the heat input rating of the boilers. Boiler efficiency increases by 3.5 percent and net generation is maintained

The study estimated the cost of conversion to be $9,057,000. The study only calculated the cost of conversion and not any related cost savings realized by a conversion.

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REV 2 – FINAL COMMENTS INCORPORATED

COAL TO NATURAL GAS CONVERSION EVALUATION

Neil Simpson Power Plant – Unit 2

B&V PROJECT NUMBER: 407186
B&V FILE NUMBER: 40.1200

PREPARED FOR

Black Hills Corporation

26 MARCH 2021

PREPARED BY

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1.0 Executive Summary

Black & Veatch has been requested by Black Hills Corporation to evaluate the concept of converting the existing Neil Simpson Unit 2 (NS2) coal-fired boiler to a fully natural gas-fired boiler. Converting to gas firing involves the design and installation of new gas supply piping, metering, and regulation in addition to replacing the existing coal-fired burners, natural-gas fired startup burners, and associated equipment with natural gas burners and electric high energy spark igniters. Conversion to gas firing reduces greenhouse gas (GHG) emissions and eliminates the cost of purchasing coal, coal handling equipment, coal firing equipment, ash handling equipment and disposal, the circulating dry scrubber (CDS) and associated equipment, and water usage/wastewater discharge treatment associated with ash handling. Because natural gas has little to no ash, gas conversion will also reduce or eliminate maintenance cleanings associated with ash deposition and fouling, such as air heater washes, boiler washes, precipitator washes, and dust control washes. Existing precipitator, coal handling, ash handling, and associated equipment would be removed from service, resulting in much lower auxiliary power consumption. Conversion of NS2 to natural gas firing results in a predicted reduction of carbon dioxide (CO_2) emissions in the range of 1,100 pounds per megawatt-hour (lb/MWh) per unit. New natural gas burners generate lower emissions during startup and normal operation while providing boiler maximum continuous rating (MCR) heat input capability. Boiler modeling calculations indicate NS2 is capable of maintaining current net generation output when converted to natural gas firing, with unit's net heat rate decreasing approximately 3.5 percent because of a slight increase in boiler efficiency and reductions in auxiliary loads.

New gas-firing equipment cost estimates were obtained from Riley Power Incorporated (RPI) and Babcock & Wilcox (B&W). Either the Coal Seam Pipeline or Bear Paw Pipeline will provide the natural gas for NS2 after the conversion, and the natural gas supplier is expected to provide the metering and pressure reducing station inside the site boundary. Therefore, the cost for that scope of work is not included in the project estimate.

Regarding environmental permitting, conversion to gas firing affects NS2's applicability to both proposed and existing environmental rules for coal fired generation assets. Investigation is needed to confirm that gas conversion would be considered a minor modification under the New Source Review (NSR) program, thereby requiring a less time-intensive and onerous permit application. Investigation may also be necessary to determine if changes in the units' stack characteristics impact Black Hills Power's ability to demonstrate through air dispersion modeling that the facility does not contribute to a violation of any National Ambient Air Quality Standards (NAAQS). Lastly, federal GHG performance standards, and how the state of Wyoming may implement those changes, are presently unknown. Because environmental regulations are constantly in flux, the situation at the time of project's initiation must be evaluated to determine impacts to the design, schedule, and cost of the project. Permitting assessment has not been included in the project cost estimate developed herein.

Estimated total installed costs for gas conversion of NS2 are summarized in Table 1-1, with details provided in Section 4.0. Total on-site project costs begin at the terminal point located at the discharge of the metering and pressure reducing station to the new gas burners, including on-site gas supply piping, a fuel gas heater, separate pressure reducing/control skids, and new burner system equipment at the boiler.

Table 1-1 Natural Gas Conversion Project Estimated Costs Summary

COST DESCRIPTION	UNIT 2
Direct Cost	
Mechanical	$2,601,000
Mechanical Installation	$441,000
Civil/Structural	$1,181,000
Electrical/Controls	$800,000
Total Direct Cost	**$5,023,000**
Indirect Cost	
Engineering Cost	$1,005,000
Construction Management	$1,005,000
Insurance, Warranty, Bonds	$126,000
Project Contingency	$716,000
Total Indirect Cost	**$2,852,000**
EPC Fee	$394,000
Owner's Cost	$788,000
Total On-Site Project Cost	**$9,057,000**
Demolition of Coal Equipment	**$3,000,000**

2.0 Introduction

Neil Simpson Unit 2 is a pulverized coal-fired unit that entered operation in September 1995. The boiler is a B&W, subcritical, opposed wall-fired boiler with no reheat circuit, featuring 12 low-nitrogen oxide (NO_X) CAJ burners. Nominal MCR is considered to be 90 megawatts (MW) gross and 80 MW net generation. The unit is equipped with one forced draft (FD) and one induced draft (ID) fan. The forced draft fan has a bypass to the scrubber that is not currently used. Three B&W 67N mills grind the coal, and primary air (PA) is supplied by three hot-side PA fans. A single bisector air heater is employed.

NO_X reduction is solely via low-NO_X burners. Particulate control is by a cold-side electrostatic precipitator (ESP), and sulfur dioxide (SO_2) removal is by a CDS located upstream of the ESP. Figure 2-1 shows a flow diagram of the boiler and flue gas system.

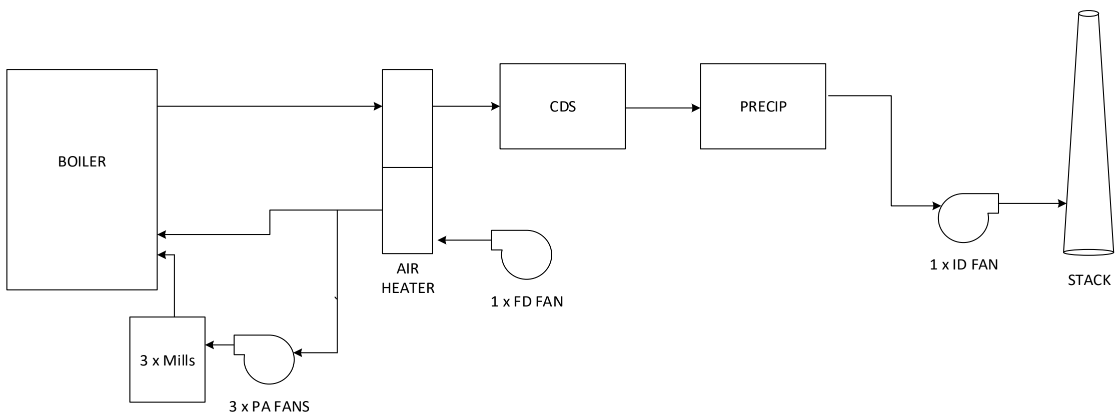


Figure 2-1 Neil Simpson Unit 2 Boiler and Flue Gas Flow Diagram

2.1 STUDY OBJECTIVE

The purpose of this study is to develop project conceptual design characteristics and a cost estimate in accordance with the Association for the Advancement of Cost Engineering (AACE) Class 5 for the conversion of the coal fired boiler at NS2 to a 100 percent natural gas-fired boiler. Conversion to 100 percent natural gas firing is a potential option being considered by Black Hills Power to lower emissions and eliminate costs associated with coal purchase, coal handling, coal firing, precipitator usage, ash handling and disposal, water usage, and treatment of wastewater from ash sluicing. This study identifies equipment upgrades and modifications required to achieve natural gas firing, provides an estimated total installed cost for the equipment and on-site gas supply, and describes the performance impacts of natural gas firing.

2.2 STUDY OVERVIEW

The study is based on replacement of coal burners, natural gas startup burners and associated equipment with natural gas burners suitable for firing gas from startup through full load operation at NS2. Natural gas burners will be sized such that 100 percent of the NS2 existing boiler MCR heat input at full unit load can be supplied by firing natural gas. It should be noted that NS2 currently is a base loaded unit.

The NS2 boiler was designed and furnished by B&W and is a radiant style configuration. The NS2 boiler is equipped with twelve (12) coal fired burners, twelve (12) natural gas startup burners, and three (3) coal pulverizers. The boiler is equipped with three levels of two coal fired burners on the front wall and three levels of two coal fired burners on the rear furnace wall. Each coal burner is provided with a natural gas-fired startup burner and a flame scanner. At full load, the capacity of NS2 is approximately 90 MW gross output power.

Implementation of full conversion to natural gas firing requires replacement of the existing coal fired system (coal burners, natural gas startup burners, coal pulverizers, coal handling, ash handling, etc.) with a new natural gas fired burner system (natural gas burners, high energy spark igniters, piping, valves, controls, burner management system [BMS], and associated equipment). This conversion will also require a significant increase in the natural gas supply to the site. Either the Coal Seam Pipeline or Bear Paw Pipeline will be used to provide the natural gas after the boiler is converted, and the natural gas supplier will be expected to provide the metering and pressure reduction station inside the plant boundary. Any new intrastate pipeline or high-pressure reducing station are not included as part of this study's cost estimate.

One additional benefit of the gas conversion may be an increase in turndown capability of the unit. Typically, turndown of a pulverized coal unit is limited by the minimum load of 2 mills. Following the gas conversion, this system bottleneck will be eliminated. Natural gas burners typically have a turndown of 1:10. Other system bottlenecks such as steam temperatures and turbine impacts may need to be evaluated to determine the new minimum load. Natural gas burners also are not subject to the same mill warm-up durations.

With natural gas conversion, all systems associated with firing coal (mills, coal handling equipment, ash handling equipment, precipitators, etc.) could be decommissioned and removed from service. Additionally, some of the air quality control (AQC) equipment should not be needed, because natural gas is relatively free of many constituents that coal contains. When burning natural gas, flue gas emissions for particulate matter (PM), SO_2, and mercury (Hg) are significantly reduced. NS2 currently uses a CDS and ESP to remove acid gases and PM from the flue gas, respectively. Due to the reduced emissions from the burning of natural gas, it is expected that both of these systems can be decommissioned in place as shown in Figure 2-2. Decommissioning should be performed by the engineering, procurement, and construction (EPC) contractor, and there are potential cost savings to Black Hills Corporation on the basis of salvage value of the equipment and materials. If Black Hills Corporation chooses instead to remove the equipment from the site, Black & Veatch estimates that it would cost about $3,000,000 to demolish the equipment needed for coal-firing, such as the coal unloaders, feeders, pulverizers, CDS, ESP, and ash handling equipment. This cost includes permitting, utility disconnects, basic cleaning of materials, and construction equipment (e.g. cranes) and labor.

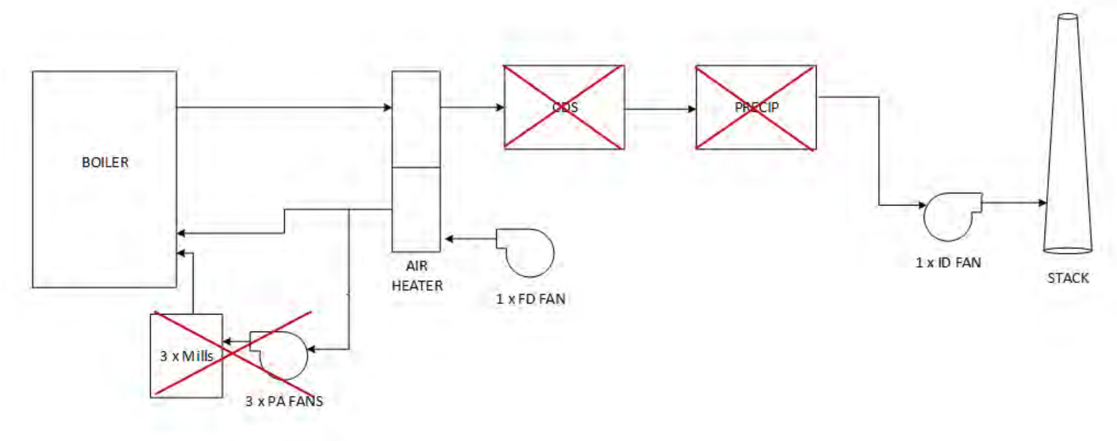


Figure 2-2 Neil Simpson Unit 2 Boiler and Flue Gas Flow Diagram – NG Conversion

Flue gas emissions of NO_x and carbon monoxide (CO) are likewise reduced but are still present when burning natural gas. Even though emissions are expected to be reduced, there is a possibility that a selective catalytic reduction (SCR) system and an oxidation catalyst will be needed for NO_x and CO, respectively. A thorough permit review is strongly recommended to confirm whether or not a gas conversion would necessitate additional AQC equipment. Since it is not known whether an SCR or oxidation catalyst are needed, they are not included in this study. However, Black Hills Power should consider that a new SCR on NS2 after a gas conversion may cost over 20 million dollars of total capital cost.

3.0 Project Concept Description

3.1 NATURAL GAS SUPPLY

Approximately 45,000 lb/h of natural gas will be required for 100 percent capacity natural gas firing for NS2. The current facility does have a natural gas line that feeds a combustion turbine, but it is not known whether or not this line has sufficient additional capacity for NS2. This study therefore assumes that a new pipeline of approximately 8 inch diameter will need to be installed within the boundaries of the plant. The natural gas pipeline will terminate along the southern boundary of the plant property, as shown in Appendix A. The natural gas supplier will provide a metering and pressure regulating station with emergency shutoff, online gas chromatograph, liquids/particulates filtering, telemetry for flow data, and associated equipment located just inside the southern site boundary. For on-site supply pipe sizing purposes, it is assumed the gas flow rate of over a million pounds per day is available at the outlet of the pressure reducing and metering station at a minimum operating pressure of 175 pounds per square inch gauge (psig).

From the metering and pressure regulation station, approximately 1,200 feet of 8 inch diameter natural gas supply piping will be routed to a water bath type natural gas heater (refer to Appendix B). The natural gas heater is an indirect-fired type heater that burns natural gas and is designed to increase the temperature of the natural gas to comply with the burner supplier's temperature requirements at the inlet to the burner control skids (e.g. stay above the water saturation temperature). The natural gas heater would be shop tested, and except for the flue gas stack and ladder, ships as a completely assembled package. Piping from the discharge of the natural gas heater goes to a natural gas pressure reducing/control skid provided by the burner equipment supplier. Because of limited space and as a safety preference to keep higher pressure natural gas outside of the boiler building enclosures, the gas heater and the pressure reducing/control skid are located outdoors.

The pressure/control station for NS2 will be shop assembled, prewired, and skid mounted. The skid includes a complete valve train with the devices prewired to a National Electrical Manufacturers Association (NEMA) 4X-rated junction box, carbon steel piping of National Fire Protection Association (NFPA) 85 compliant design, and American Society of Mechanical Engineers (ASME) B31.1 construction to supply and control natural gas to the burner gas guns. The main valve train consists of a main safety shutoff valve, burner header atmospheric vent valve, main fuel flow control valve, minimum flow bypass valve, constant fuel pressure regulator, flowmeter, strainer, manual shutoff valve, vent valves, pressure switches, fuel pressure gauge, and piping. Each pressure/control skid maintains a pressure of 60 psig at the inlet to the natural gas burners.

All natural-gas system safety valves and venting systems will be provided in accordance with NFPA 85 Boiler and Combustion Systems Hazards Code requirements. These components are in the scope of supply of the burner equipment vendor and are described in the following sections.

3.2 NATURAL GAS BURNER SYSTEM

3.2.1 Coal to Natural Gas Conversion

Black & Veatch requested budgetary proposals from B&W and RPI based on the NS2 coal to natural gas firing project concept. RPI, a subsidiary of Babcock Power, approximates a cost of about $3,000,000 for the equipment supply for NS2's gas burners. B&W quotes a cost of $2,500,000. Since B&W provided the boiler and burners at NS2, their quote is carried forward due to their familiarity with the facility.

RPI estimates the design, manufacturing, and delivery of the new gas firing equipment is approximately 44 weeks after receipt of an order, and B&W estimates that 36 to 42 weeks will be required.

3.2.2 Natural Gas Conversion Equipment

When converted to gas firing, NS2 will have 12 new, low NO_x, natural gas burner guns, with six on the front furnace wall and the other six on the rear furnace wall. NS2's existing 12 coal fired burners and natural gas startup burners will be replaced with 12 new low NO_x natural gas burners, plus high energy spark igniters, main flame ultraviolet (UV) scanners with optic extensions, and a BMS. The gas-firing equipment includes gas supply piping, burner guns, flow regulators, valve racks with safety shutoff valves, vent valves and piping, manual shut-off valves, high energy spark igniters with associated equipment, flame scanners, and BMS control and monitoring equipment. Conversion to gas firing as described herein prohibits the ability to fire coal in the future (although gas burners could be purchased which do allow continued coal firing). Refer to Table 3-1 for a list of conversion modifications.

Table 3-1 Natural Gas Combustion Equipment Neil Simpson Unit 2

COMPONENT	UNIT DESIGN PARAMETERS
Unit Supply	8-inch diameter piping from the main supply line with branch to each unit's pressure reduction and control skid.
Natural Gas Burners	Twelve natural gas guns, each with about 85 MMBtu/h heat input, perforated plate diffusers, air chamber assemblies with directional vanes, burner front plate modifications and gas gun supports, burner secondary air damper modifications, and UV flame scanners with fiber-optic extensions.
Main Natural Gas Valve Train	One preassembled, prewired, complete main valve train, prewired to NEMA 4X junction box, NFPA 85 and ASME B31.1 compliant; main safety shutoff valve, burner header atmospheric vent valve, main fuel control valve, minimum flow bypass valve, constant fuel pressure regulator, flowmeter, strainer, header high/low pressure switches, manual shutoff valve, fuel pressure gauges.
Main Burner Gas Gun Piping and Valve Spools	Twelve complete prefabricated main burner valve spools for shutoff and venting of natural gas at each burner; NFPA 85 and ASME B31.1 compliant; individual burner safety shutoff valves, atmospheric vent valve, pressure gauge, piping/fittings, flexible stainless-steel hose.

COMPONENT	UNIT DESIGN PARAMETERS
BMS and Combustion Controls System (CCS) Logic	BMS protection logic and CCS digital and analog (SAMA) control logic furnished by burner system supplier for implementation by customer. Hardware, power, interconnect, and programming are by customer.
Boiler Heating Surface Modifications	None anticipated.
FD Fans and Motors	Existing fans remain in service to supply the combustion air to the wind box.
Bisector Air Heaters and Ductwork	Existing air heaters remain in service without modification, except that hot primary air ductwork will be isolated from the wind box.
Overfire Air (OFA) Ports	Four of each of the following: burner/OFA partition plates and OFA port air flow measurement probes.

3.2.3 Predicted Emissions Firing Natural Gas

Estimated performance and emissions for NS2 with 100 percent natural gas firing are as follows, with the qualification that for guaranteed emissions a detailed study for NS2 must be performed and confirmed by the Suppliers:

- NO_x: 0.10 – 0.17 lb/MMBtu
- CO: 50 - 200 ppm @ 3 percent O_2
- Particulate: Not applicable
- Burner Turndown: 4:1

The predicted NO_x emissions of 0.10 to 0.17 lb/MMBtu (without FGR) are below the anticipated permitting levels of 0.20 lb/MMBtu. Based on RPI provided information, NO_x level reductions because of the installation of new low NO_x gas burners, coupled with changes to the OFA system, should result in NO_x levels below those required for permitting.

3.3 INSTRUMENTATION AND CONTROLS

A new BMS and firing rate CCS with field device inputs/outputs and control logic will be required for the new natural gas burners, igniters, and other equipment on each unit. The burner supplier will provide recommended control and protection logic for the BMS and CCS; however, the necessary hardware, software implementation, and installation are by others. Estimated costs to implement the BMS hardware and software for each boiler and to make modifications to the plant CCS, including an NFPA 85 audit of the BMS logic implementation, are included in the cost estimate.

3.4 HAZARDOUS AREA CLASSIFICATION

NS2 uses natural gas during startup, so it is assumed that areas where the natural gas supply lines have potential leak points have been properly classified with all equipment being properly designed and installed to meet the classifications' requirements. However, in the event this is not the case, NFPA, National Electrical Code (NEC), and National Electrical Safety Code (NESC) standards define hazardous area classifications at electrical generating stations for areas where flammable and/or combustible liquids, gases, or dusts are handled. Hazardous area classifications determine the criteria for selection and installation of properly rated electrical equipment to minimize the possibility of ignition. The NEC (NFPA 70) defines construction and installation requirements for electrical equipment within the boundaries of hazardous areas, such as explosion-proof enclosures, installation of purge air systems, or use of intrinsically safe systems. Electrical installation methods include raceway systems specifically rated for the hazardous area and sealing off raceways when crossing hazardous area boundaries. Assuming the existing boiler buildings and burner decks are classified as well-ventilated, NFPA 497 requires the area around potential gas leaks and gas burners to be rated a Class I, Division 2, Group D hazardous area for electrical equipment.

Long sections of welded pipe without any flanges, valves, or instrument connections will not require a hazardous area classification. However, pressure reduction/control skids, burner header trains, individual valves, and instrument connections all have potential leakage points. Existing electrical components and raceway, whether located in the boiler buildings or outside, that are within a 15-foot sphere of potential leak points and not presently rated for a Class I, Division 2, Group D environment will have to be replaced with appropriately rated equipment or relocated. Examples include lighting fixtures, power receptacles, communications equipment, power distribution equipment, control panels, electric control drives, and associated raceway. A detailed study on hazardous areas will need to be performed to define the area classification in accordance with NFPA and identify equipment requiring upgrade or replacement. The costs for substantial electrical equipment replacement for compliance with area classification have not been included in the cost estimate.

3.5 FIRE PROTECTION IMPACTS

In general, converting from coal firing burners with natural gas igniters to natural gas burners and igniters will not require additional fire protection. The fire protection study and design basis developed during this project's design should be submitted for review and approval by the authority having jurisdiction (e.g. fire marshal, as applicable).

Outdoor gas fired boilers, fire hose stations, and portable extinguishers are typically sufficient for fire protection. When natural gas supply lines are routed through a building or enclosed area, there is potential additional fire protection and gas detectors that may be required. This study assumes the main natural gas supply lines and pressure/control skids are located outdoors to minimize potential issues.

3.6 FLUE GAS DUCTWORK MODIFICATIONS

After conversion to natural gas, NS2 will not require the use of the CDS or the ESP due to significantly lowered emissions. Therefore, CDS and its related system components can be removed from service. It is recommended, however, the ESP remain in service for a period of time following the conversion to natural gas to aid in the removal of any residual fly ash that may be lingering in the duct work due to firing coal. Once the NS2 staff determines that the ductwork downstream of the economizer to the inlet of the ID fan is relatively free of fly ash, the ESP can be removed from service and retired in place.

Due to the CDS no longer lowering the flue gas temperature, the flue gas will have increased temperatures. The ID fan, ductwork, and stack will need to be thoroughly reviewed during detailed design efforts to ensure they are capable of handling the changes to the flue gas properties. If the increased temperature proves to be problematic, the water lances in the CDS may need to be used to lower the temperature.

3.7 AIR HEATER FLUE GAS OUTLET TEMPERATURE

As detailed in Section 5.3, the flue gas temperature at the NS2 economizer outlet is predicted to decrease with natural gas firing compared to firing pulverized coal, and this will have an impact on all downstream equipment. The air heater is located immediately downstream of the economizer in the flue gas' path, and the air heater's baskets are expected to accommodate the increased temperatures. After the air heater, the flue gas enters the CDS. The flue gas is presently cooled when passing through the CDS. With the CDS removed from service for natural gas firing, the impact of higher exhaust temperatures on the existing stack flue was addressed. The temperature of the flue gas entering the carbon steel stack is estimated at approximately 320° F (after the air heater and with no cooling from the CDS). The flue gas temperature is well below the maximum temperature allowed for carbon steel, so there should be no adverse effects on the chimney, which is a dual walled, steel stack.

3.8 COMBUSTION AIR AND FLUE GAS DRAFT EQUIPMENT

As shown in Figure 2-2, the mills and PA fans will no longer be utilized following the natural gas conversion. Given the FD fan and the air heater are already sized for 100 percent of the combustion air, the FD fan and air heater should be adequate following the gas conversion. The ductwork from the air heater air outlet to the boiler (including the windbox) may need to be reviewed during detailed design to confirm whether the sizing is adequate. This will depend on the anticipated excess air percentage determined by the gas burner supplier.

The ID fan is expected to have a significant reduction in duty following the removal from service of the CDS and ESP. Given the issues noted by the plant in using the inlet vanes to turn down the ID fan operation, a natural gas conversion may offer additional strength to the decision to upgrade the actuator for the inlet vanes or consider a variable frequency drive (VFD) for the ID fan.

4.0 Basis of Estimate

The basis for the cost estimates provided for gas conversion is described in this section. Estimates for new gas-fired burners were provided by RPI and B&W, and due to B&W's familiarity with the facility as the original equipment manufacturer (OEM) of the boiler and burners, B&W's costs are used. Equipment supplier estimates are specific for application at NS2 but are not based on detailed bid specifications. The project cost estimates provided are based on a full EPC contracting approach and have an accuracy in accordance with AACE Class 5. All engineering design, procurement, construction management, construction, and startup/commissioning will be accomplished by the EPC contractor. Costs will vary based on selection of specific options and further investigation, detailed design, and a more detailed estimate. The installation and indirect costs for this project were calculated based on past experience by Black & Veatch on other projects.

4.1 DIRECT COST ASSUMPTIONS

The following assumptions are associated with direct costs:

1. Direct costs include the costs associated with the purchase of equipment, erection, and installation contractor services.
2. On-site gas regulating equipment, piping, gas heater, gas burners, burner control skids, and other materials downstream of the metering and regulating station are included.
3. All costs are expressed in 2021 dollars. Costs used from Black & Veatch's past projects were escalated using the Chemical Engineering Plant Cost Index (CEPCI), and with 2021 information unavailable, 2021 dollars were used.
4. No allowance is included for operational spare parts.
5. With the exception of the coal firing components located in the immediate vicinity of the coal burners, any activities associated with the demolition of the existing coal firing related systems (silos, coal/ash handling equipment, etc.), are not included in the project scope. The estimate stops at the replacement of the coal fired burners.

4.2 INDIRECT COST ASSUMPTIONS

The following assumptions are associated with indirect costs:

1. Costs are included for construction equipment, small tools and consumables, safety and medical services, insurance premiums/bonds/warranty, equipment checkout, calibration and testing, commissioning/startup, and operating training.
2. Costs for detailed design engineering and technical support during construction, training, and closeout are included.
3. Field construction management services include field management staff; support staff; field contract administration; field inspection and quality assurance; project controls; technical direction; and management of commissioning, startup, and testing.

4. Costs for EPC contractor general administration and fee are included.
5. Contingency of 10 percent on all direct and indirect costs is included.
6. Costs for insurance, payment and performance bonds, and warranty at 2.5 percent of direct costs are included.
7. No federal, state, county, and local taxes are included.
8. Owner's costs at 10 percent of total contracted cost are included. Such costs would include, but not be limited to, permitting and licensing; financing and interest; builder's risk insurance; operating staff during startup; fuel, water, and electricity used during startup; operating equipment; and supplies.
9. Long-term operating spare parts are not included.

4.3 ESTIMATE RESULTS

Estimated total installed costs for conversion of NS2 to 100 percent natural gas firing are presented in Table 4-1.

Table 4-1 Gas Conversion Total Installed Cost Estimate Summary

COST DESCRIPTION	UNIT 2
Direct Cost	
Mechanical	$2,601,000
Mechanical Installation	$441,000
Civil/Structural	$1,181,000
Electrical/Controls	$800,000
Total Direct Cost	**$5,023,000**
Indirect Cost	
Engineering Cost	$1,005,000
Construction Management	$1,005,000
Insurance, Warranty, Bonds	$126,000
Project Contingency	$716,000
Total Indirect Cost	**$2,852,000**
EPC Fee	$394,000
Owner's Cost	$788,000
Total On-Site Project Cost	**$9,057,000**
Demolition of Coal Equipment	**$3,000,000**

5.0 Performance Impact Estimates

5.1 PERFORMANCE ESTIMATE BASIS

Black & Veatch performed combustion calculations using the B&W's original boiler performance data sheet and the coal properties provided in Table 5-1. The second case was based on firing 100 percent natural gas (analysis in Table 5-2) using the gas analysis from the Bear Paw pipeline.

Table 5-1 Babcock & Wilcox Design Coal

BABCOCK & WILCOX DESIGN COAL	VALUE
Higher Heating Value, Btu/lbm	7,950
Ultimate Analysis (%)	
Moisture	30.00
Ash	7.50
Carbon	46.70
Hydrogen	3.10
Nitrogen	0.70
Sulfur	0.85
Chlorine	0.01
Oxygen (balance)	11.14
Total (%)	100.00

Table 5-2 Study Design Natural Gas

NATURAL GAS	VALUE
Higher Heating Value, Btu/scf	970
Ultimate Analysis (%)	
Methane	96.02
Ethane	0.00
Propane	0.00
Butane	0.00
Pentane	0.00
n-Hexane	0.00
Carbon Dioxide	2.11
Nitrogen	1.87
Total (%)	100.00

5.2 PERFORMANCE RESULTS

To determine impacts of gas firing compared to burning coal, Black & Veatch first developed performance estimates using 100 percent coal properties shown in Table 5-1. This project utilized the Electric Power Research Institute (EPRI) Vista program to model the performance impacts of coal to gas conversion on NS2's boiler. Vista is a detailed modeling program specializing in coal-fired boilers, which has been developed over 30 years by EPRI and Black & Veatch, and this study utilized a model of NS2 that was developed in late 2020 for a heat rate study at the Neil Simpson Complex. The program contains a detailed slice-by-slice heat transfer model to calculate the impacts upon steaming rate and temperature, required air and fuel flows, and flue gas conditions and composition.

The Vista model indicated NS2 can achieve the same full load gross MW output on natural gas as when firing coal. The Vista model predicts NS2's net heat rate and boiler efficiency will slightly improve when combusting natural gas. This is due to a few factors. A benefit to burning natural gas is that fewer auxiliary loads are required, and the boiler requires less excess air to combust natural gas (the final excess air requirements will be dictated by the burner vendors during detailed design to meet NO_x guarantees). Somewhat countering this benefit are higher unrecoverable latent heat losses, primarily due to the increased hydrogen that is combusted, which decreases the boiler efficiency. In addition to slightly improved boiler performance and heat rate, the emissions of SO_2, NO_x, PM, and CO_2 are all expected to significantly decrease. The performance estimates for NS2 are presented in Table 5-3.

Table 5-3 Neil Simpson Unit 2 Natural Gas Firing Performance Estimates

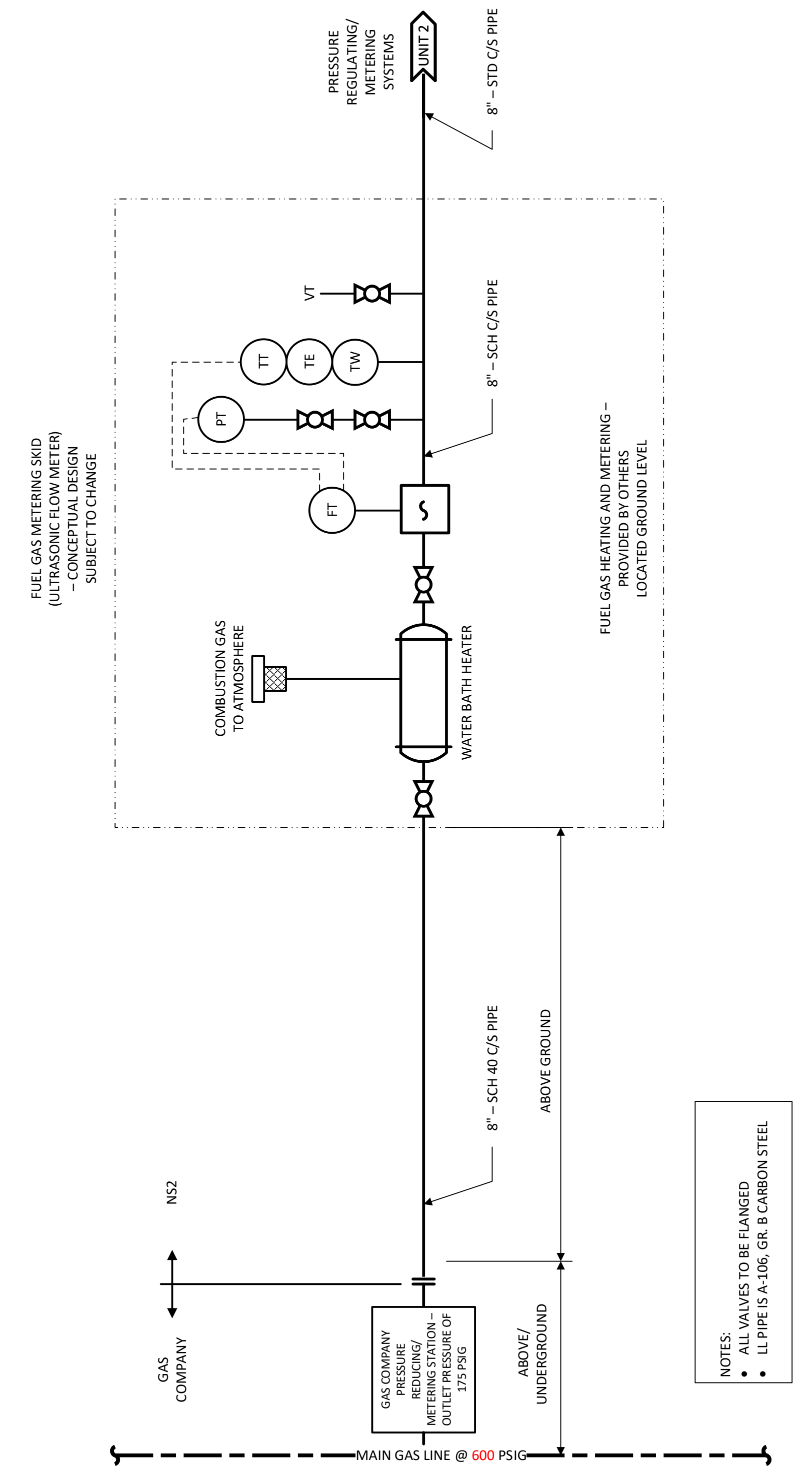
PARAMETER	BASE CASE COAL FULL LOAD	CASE 1 NATURAL GAS FULL LOAD
Site Conditions		
Ambient Pressure, psia	12.49	12.49
Ambient Temperature, ° F	91	91
Ambient Relative Humidity, %	60	60
Performance		
Gross Plant Output, MW	89.97	89.97
Auxiliary Load, MW	9.73	7.57
Net Unit Output, MW	80.24	82.40
Coal Input, MMBtu/h (HHV)	1,060	NA
Natural Gas Input, MMBtu/h (HHV)	NA	1,050
Boiler Efficiency (HHV), %	83.38	83.98
Net Unit Output, Btu/kWh (HHV)	13,204	12,744
Flue Gas Temperature @ Econ Outlet, ° F	807	737
SO_2 Emissions, lbm/MMBtu	0.20	0.00
Stack NO_x Emissions, lbm/MMBtu	0.23	0.17
Particulate Emissions, lbm/MMBtu	0.02	0.00
CO_2 Emissions, lbm/MWh net	2,793	1,520
Stack Temperature, ° F	160	280
Stack Flue Gas Flow, ft^3/min	338,048	326,000

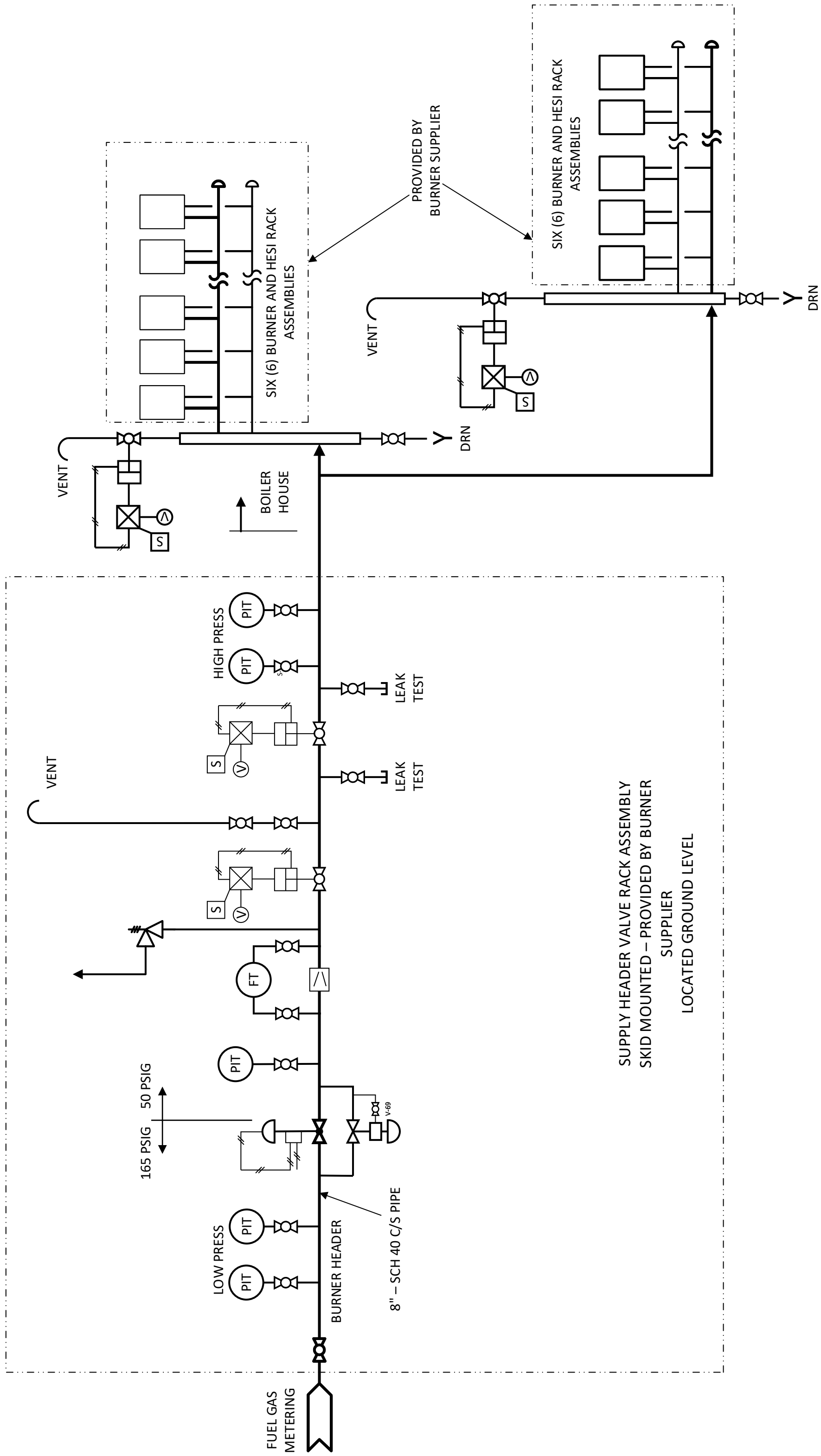
Notes:
1. Based on runs from Vista model received from Neil Simpson November 2020.
2. Coal fired emissions are those hard set in the Vista model.
3. Gas fired emissions are those based on estimates from the burner suppliers with a small reduction of NO_x in the SCR to achieve the same emissions as set in the Vista program for coal firing.

Appendix A. Proposed Natural Gas Pipe Routing

Natural gas is taken from the gas meter by the combustion turbines and routed to the southern part of the boiler building. The distances are approximate and rounded up to 1,200 ft for the study.

Appendix B. Proposed Natural Gas P&IDs




SIX (6) BURNER AND HESI RACK ASSEMBLIES
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S
FT
PIT
50 PSIG
165 PSIG
LOW PRESS
PIT
PIT
BURNER HEADER
8" – SCH 40 C/S PIPE
SUPPLY HEADER VALVE RACK ASSEMBLY
SKID MOUNTED – PROVIDED BY BURNER SUPPLIER
LOCATED GROUND LEVEL
FUEL GAS METERING

LIFE ASSESSMENT REPORT UPDATE

Neil Simpson Unit II has delivered baseload power since 1995. A life assessment study about the unit was first conducted in October 2019. This Black & Veatch study updated that report. The study considered new information, assessed modifications, updated previous costs and any new costs, and refreshed recommendations to operate the unit until 2039.

The purpose of the update is to (1) incorporate new information into the report and refresh previous recommendations, (2) assess any modifications that have been performed to the facility and the impact they have on any previous analysis, and (3) update costs previously developed and provide costs for any new recommendations and modifications expected to meet environmental regulations passed since the previous life assessment report or foreseen in the future that would require updating the air quality process equipment, including addition of an SCR, baghouse, and scrubber.

REV 2 –FINAL COMMENTS INCORPORATED

IRP STUDY LIFE ASSESSMENT REPORT UPDATE

Neil Simpson Power Plant – Unit 2

B&V PROJECT NO. 407186
B&V FILE NO. 40.1000

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PREPARED FOR

Black Hills Corporation

26 MARCH 2021

PREPARED BY

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1.0 Executive Summary

The Neil Simpson Unit 2 (NS2 or Unit) was built and became operational in 1995 and has been operating primarily as a base load unit for 25 years. Black Hills Corporation (Black Hills) contracted with Black & Veatch in November 2020 to update Black & Veatch's October 2019 Life Assessment of Neil Simpson Unit 2. The purpose of the update is to incorporate new information into the report and refresh previous recommendations, assess any modifications that have been performed to the facility and the impact they have on any previous analysis, and update costs previously developed and provide costs for any new recommendations and modifications expected to meet environmental regulations passed since the previous Life Assessment report or foreseen in the future which would require updating the air quality process equipment, including addition of an SCR, baghouse and scrubber. This updated report includes assessment and costs to run the plant to 2039.

Black & Veatch did not evaluate any options to extend the plant life beyond 2039.

Black & Veatch thanks Black Hills staff for their timely help providing historical maintenance, operating and budget information for Black & Veatch's review and analysis. Due to COVID-19 restrictions, no site visits were conducted. Black Hills home office and plant staff meetings were performed virtually.

Black & Veatch's analysis of NS2's information created a snapshot of the Unit's current operating and mechanical condition. The current Unit condition, as of December 2020, was used as the basis for forecasting plant system/equipment maintenance and budget requirements for operation until 2039.

Cycling operation analysis was not a part of this study; however, reference to cycling is included to help characterize the impacts of cycling. Black & Veatch recommends that Black Hills perform a cycling study. The results of the cycling study will identify the specific effects of cycling to NS2 and provide guidance on what plant systems and equipment will need modifications or replacement to minimize the impact of cycling until 2039.

Black & Veatch finds Neil Simpson in good condition and well maintained. Table 1-1 summarizes NS2's key performance indicators (KPI's) for the past 6+ years. High reliability factors are indicative of Black Hills's good operation and maintenance (O&M) strategy. Analysis confirms that many of the critical plant equipment and sub-components have been well maintained or replaced when near or at their end of life. Historical operating, maintenance and capital improvement and replacement practices are appropriate. Black Hills must continue with appropriate levels of O&M and capital investment commitment to provide reliable and safe service until 2039.

Table 1-1 Key Performance Indicators

YEAR	AVERAGE AVAILABILITY EAF	NET AVGERAGE NCF %	FORCED OUTAGE FACTOR
2014	86.2	93.4	5.9
2015	96.7	49.2	0.5
2016	88.8	93.7	8.4
2017	75.6	77.5	9.2
2018	90.8	98.8	6.7
2019	93.1	94.8	1.4
*2020	93.8*	92.8*	1.9
* Data thru 10/2020			

Black & Veatch found a few gaps in the maintenance and capital replacement strategy. There are maintenance process improvements that can be performed to improve the reliability and prepare the unit for possible future cycling operation. Areas identified as needing improvement are the following:

- Develop formal boiler mapping program.
- Develop critical equipment Inspection and Testing program.
- Perform asset life analysis on systems and equipment.

Appendix A summarizes Black & Veatch's updated O&M and capital forecasted expenditures to 2039. Capital forecasts provided by Black Hills are not included in Appendix A. Items listed in Appendix A have been categorized into the following categories: Safety, Environmental, Reliability and Infrastructure.

2.0 Background

Power plants are typically designed for a life of 30 plus years. The financial aspects of the plant may assume the plant life (or depreciated life) to be 40 - 50 years. NS2 began service in late 1995 with a depreciated end of life to be 2039, or 45 in service years.

With diligent O&M practices, power plants can operate much longer than the 30-year design life. If the plant was nominally maintained, with little capital renewal and replacement performed after 30 years, the plant would not operate as designed, may be unsafe to operate, and unreliable. A company would have to invest a large sum of money into a plant in this condition to reinstate the design rating and performance to operate for the remaining depreciation life. An investment of this amount may not be in the best interest of the company and stakeholders. The company and plant would then be in the position of deciding between the feasibility of continued operation or alternative generation solutions.

Power plant system equipment experience various levels of degradation during their service life. Equipment service life is determined by three key factors; safety, efficiency and reliability. These factors are affected by operating conditions, O&M practices, and obsolescence. Power plant equipment manufactures provide specific O&M procedures to maximize equipment performance and reliability for the intended service and life. Power plants are dynamic in that many O&M factors will cause the equipment to operate "outside" of design parameters creating accelerated degradation leading to failure or necessary replacement before the end of its design life. Some of the more severe mechanical conditions include: continuous and fluctuating high temperatures, pressure, rotation, corrosion and abrasion. Electrical and control systems are exposed to extreme environmental and operating conditions. Control systems require update of hardware and software to keep up with technology changes. All of these factors take part in reducing component service life. Periodic replacement and refurbishment is required to ensure safe, reliable, and efficient operation of any plant until the end of its depreciation life.

Black HillsNS2 O&M strategy and O&M programs appear to be appropriate to operate, maintain and monitor equipment condition. Plant staff does a good job operating and maintaining the power plant systems and equipment by exercising prudent and appropriate replacement and refurbishment actions to mitigate impact to safety, reliability and efficiency. This level of effort must be maintained to ensure operation until 2039.

3.0 Scope of Assessment

Black Hills Corporation requested Black & Veatch to perform a Life Assessment of the NS2 power plant in 2019 with the goal to identify the actions necessary to continue operation of the unit for 20 additional years (2039). The intent of the 2020 Life Assessment is to update the 2019 assessment with the most recent information to provide a current "snapshot" of unit condition considering capital expenditure and maintenance process improvements that affect NS2's safety and environmental compliance and performance. Update of the report utilized historical and updated maintenance and outage information including information from the March 4, 2020 minor outage and Black Hills's scheduled capital expenditure and outage forecasts.

The assessment reviewed historical and forecasted O&M practices, forecasted renewal and replacement capital (CAPX) allocations and forecasted capital improvement expenditures required to meet best available technologies (BAT) for current environmental regulations until 2039. Appendix A lists recommendations and cost estimates which have a bearing on the continued operation of NS2. Black & Veatch's opinion is based on the availability of relevant information. Qualified engineers in Mechanical, Environmental, Electrical and Controls Engineering, and Operations & Maintenance have reviewed the condition of this Unit and were used to develop the recommendations contained in this report.

NS2 Life Assessment assumes the emissions permits for the plant are all in place and the plant is compliant. The forecast further assumes that emissions regulations, including air, water and solid wastes remain unchanged.

4.0 Equipment Assessment

Neil Simpson 2's boiler is rated for 778,000 lbs/hr steam at 1,005°F and 1,635 psia. The turbine is rated for 88,900 kW @ 3,600 RPM with 1,000°F steam at 1,535 psia; steam is condensed through a forced draft Air Cooled Condenser (ACC). The generator is rated at 105,600kVA with a power factor (PF) of 0.90; power leaves the building at 13,800V.

The Life Assessment study includes the following systems and sub systems:

- Steam Generator
- Boiler Fuel
- Boiler Air and Gas
- Turbine
- Generator and Exciter
- High Energy Piping
- Auxiliary Equipment / Balance of Plant
- Electrical Equipment
- Controls
- Environmental - Air Pollution Control Equipment
- Chimney
- Infrastructure

4.1 STEAM GENERATOR

The steam generator is a pulverized coal, balanced draft, natural circulation, subcritical pressure, "Carolina" type, radiant boiler (RB) capable of producing superheated main steam at 1,620 psig and 1,005°F while firing coal. Wyodak coal is the design fuel for the Unit with the Unit converted to use natural gas for startup/shutdown only. NS2 is not permitted to burn "dual" fuels for supplemental natural gas firing. Modification of air permits would be required if "dual" fuel firing is considered.

The major components provided with the steam generation system are the steam generator (boiler), coal burners, coal bunkers, coal feeders, coal pulverizers, pulverizer seal air fans, superheat desuperheater, pulverizer inerting steam desuperheater, and coal silo and coal feeder outlet slide gate valves. The major components within the steam generator include the furnace enclosure, convection pass enclosure, steam drum, primary and secondary superheaters, economizer and the superheater attemperator.

Over the years Babcock & Wilcox (B&W) has issued numerous service bulletins related to proper equipment, O&M, and potential safety hazards associated with B&W supplied equipment and materials. These bulletins have been issued in two formats – Technical Service Bulletins (TSB) and Plant Service Bulletins (PSB). TSB's are more specific to a particular type of unit or to a particular piece of equipment. PSB's are more generalized and can cover a wide range of boiler and equipment. Items called out in these bulletins should be addressed on a one-time basis or as the issues occur during the life of the Unit. In addition, B&W has developed "Standard Recommendations for Pressure Part Inspection During a Boiler Life Extension Program" Attachment B as additional information for plants to maintain equipment.

These PSB's, TSB's and inspection standards are a good baseline for an NS2 boiler maintenance program.

Black Hills has not reviewed plant documentation on previous B&W and non-B&W inspections of RB-623 to update which service bulletin inspections have been performed. Black & Veatch review of service bulletin documentation and discussion with NS2 staff found gaps in the documentation. Black & Veatch recommends NS2 track service bulletins and their deposition in the enterprise asset manager system (EAM). Migration of information into EAM is in progress.

Service bulletin inspections and testing which results in CAPX replacement projects or O&M repairs have been found to be documented by work orders in EAM.

4.1.1 Furnace Enclosure

4.1.1.1 Boiler Exterior

During the 2019 Black & Veatch site visit walkdown the boiler, boiler house and surrounding equipment and structures were observed to be in good visual condition. Housekeeping was good with little coal dust residual on surface areas. Black Hills should continue to diligently address safety and housekeeping issues by addressing and correcting them as soon as possible.

B&W performed a boiler inspection during the 2017 major outage. As a result of their inspection, a boiler inspection punch list was issued to Black Hills. B&W left site prior to the end of the outage and was unable to verify if their recommendations were implemented prior to the end of the 2017 outage. Black & Veatch did not investigate the deposition of these recommendations during the 2019 site visit. Discussion with plant maintenance in 2021 confirmed all B&W recommendations have been addressed. In certain instances, preventative maintenance (PM) work orders have been written for continued monitoring.

4.1.1.2 Boiler Pressure Parts

Black Hills has performed boiler tube and superheater inspection, repair and replacement of various pressure parts from 2010 through 2017. Boiler pressure part replacement is typically identified through analysis of tube and header testing, comparison of operation to design parameters, unit operating characteristics and recorded maintenance frequency. B&W's "Standard Recommendations for Pressure Part Inspection During a Boiler Life Extension Program" is a good reference source of boiler components failure mode and types of testing which should be performed to identify these failure modes.

No additional pressure part inspection and testing information is available since 2019.

Review of Black Hills NS2 data shows the Unit's pressure parts have had routine inspections and testing of the boiler, superheaters and economizer tubes from 2010 through 2017. Boiler reliability has been good as a result of this testing program. Black Hills must continue performing inspections and testing during scheduled minor and major outages. In 2020 Black Hills implemented "Boiler Aware", a boiler maintenance and data acquisition software program. Additionally, Black Hills has assigned a dedicated engineer to champion implementation and to maintain the Boiler Aware program and boiler maintenance program.

Review of available information identified missing boiler inspection and testing data listed in Table 4-1. Addressing this missing data will help future outage planning scope of work and capital budget forecasting. Additionally, it is important to have up to date data to use as a baseline for base load operation. If the Unit changes operation mode, i.e., load cycling or hot and cold cycling, this base line will be used to identify cycling effects and accelerated rate of degradation to the boiler components.

Table 4-1 Boiler Pressure Part Data Gaps

BOILER SECTION	DATA REQUIRED	JUSTIFICATION
Secondary Superheater (SSH)	Oxide thickness and Metallurgical analysis	Quantifies SSH inside tube surface condition and degree of thermal conductivity which affects material creep properties and high pressure (HP) inlet nozzle turbine solid particle erosion (SPE)
Secondary Superheater Header	Header ligament and tube bore	Identify early stage creep damage
Steam Drum Internal	Visual and non-destructive evaluation (NDE) for drum internal condition	Water chemistry effects, steam separators and inner chemical feed piping, bolting, plate and shell penetration condition.
Steam Drum External	Visual and NDE drum riser piping and safety valve internal connections	2017 B&W inspection highlight needed repairs. No major issues.
Safety Valve	Inspection, testing and calibration	Information not reviewed – This data should be driven by periodic Insurance and Statutory requirements.

Black Hills Water Chemistry staff noted NS2's first chemical cleaning in 2014 was performed with less-than-optimal results. Based on Black Hills records, a successful chemical cleaning was performed (WO# 10050096) during the 2019 outage. Tube samples taken from the boiler indicated sufficient cleaning was accomplished. Tube samples will be taken again in 2024 to check deposition loading and to begin planning a chemical cleaning in 2027. Black & Veatch recommends chemical cleaning frequency be determined by periodic tube sampling and boiler water quality monitoring. Black & Veatch agrees with Black Hills's assessment and chemical cleaning plan. Budget estimate for the next cleaning is $334,000.

Appendix A includes estimated costs for reoccurring chemical cleaning until 2039.

4.1.1.3 Boiler Tubes

Boiler tube failures typically have the largest impact on unit reliability. Preventive measures of inspection and testing along with repair and replacement of deteriorated materials will improve reliability, but not eliminate tube failures. While NS2 boiler tubes have various degrees of degradation, there are areas which need replacement in order to maintain reliability until 2039.

Black Hills capital budget in 2021 and 2025 shows funds budgeted for testing and major boiler repairs. Black & Veatch reviewed the planned scope of work, finding the work to be testing, repairs and selected tube section replacement. Based on information provided, the 2019 and 2021 boiler tube replacement recommendations remain the same. Appendix A includes estimated costs for future boiler tube replacement.

Furnace Waterwall tube thickness testing in the area between the burners and over-fire air (OFA) ports has identified a notable degree of waterwall wastage. This area of the boiler creates a reducing atmosphere which accelerates tube metal wastage. Black Hills has been using several different methods of external tube coating to reduce the wastage rate. Waterwall panels constructed of spiral welded tubes with an Inconel material has provided good success in minimizing or eliminating material wastage. Black Hills has only replaced sections as required and has not performed a wholesale replacement of this area with weld overlay panels. Continued section replacement of waterwall tubes (panels) should provide acceptable service without wholesale waterwall replacement. Appendix A does not include estimated costs for partial waterwall panel replacement.

The Furnace Rear Arch Tube were non-destructive evaluation (NDE) thickness tested in 2017 and show tubes between platform levels 8 – 12 (arch tubes) with material thickness reduction of 15 to 30 percent of nominal tube wall thickness. These tubes will require replacement and should be considered for replacement with other furnace tube replacement work.

The Front Convection Pass (screen tubes) show moderate to high tube metal reduction. Information provided does not confirm if these front convection pass tubes have been replaced. Black & Veatch recommends planning for replacement of the front convection pass (screen tubes) at the next major outage.

Appendix A includes estimated costs for replacement of the furnace rear wall upper panels and convection pass screen tubes.

Capital expenditure information indicates boiler roof tubes have been replaced in 2017. Specifics of the tube replacement location and quantity was not provided. Boiler inspection reports do not include furnace and convection pass roof tube thickness data. Service records do not indicate there are issues with the furnace and convection pass roof tubes. Black & Veatch does not anticipate the replacement of the convection pass roof tubes before 2039.

Black & Veatch recommends NDE testing and mapping of the furnace and convection pass roof be performed to monitor their condition. Replacement and NDE costs for furnace and convection pass roof tubes have not been included in Appendix A.

The Economizer is reported to be in good condition according to B&W's 2017 inspection report. There are areas of minor erosion but nothing requiring immediate attention. BHE should continue to inspect, repair or replace tube shields to help minimize tube erosion. Special attention should be given in the sootblower alleys. Unprotected tube surfaces show signs of erosion polishing; however, conditions are not concerning at the time of inspections. There have been economizer tube leaks in the past, although no leak trends are developing.

Economizer erosion will continue and will begin to affect the boiler reliability. Continued cycling will induce additional thermal stress cycles which affect economizer performance. The economizer is not equipped with a recirculation system. A recirculation system will reduce economizer thermal shocking during unit startup. Interviews confirmed there are no current economizer steaming issues during startup. This feature is beneficial if the unit begins on-off cycling.

Cost estimates for replacing the economizer and installing an economizer recirculation system have been included in Appendix A.

Secondary Superheater tubes (SH) typically have a service life of 20 – 25 years. The NS2 SH appears to be in good condition. SH testing in 2012 shows SH outlet tube assembly number 4 with tube metal thickness reduction between 80 – 90 percent. Information provided does not show the identified areas as repaired or replaced. The SH inlet lower hairpin bends were replaced in 2017. Oxide thickness testing will provide additional SH inlet and outlet section health verification. Replacement of the SH is dependent on the tube metallurgical condition, oxide scale thickness, and continued maintenance of the SH element support and tube spacer system.

Black & Veatch recommends performing an ultrasonic NDE survey on the SH inlet and outlet tube sections to obtain a comprehensive evaluation to determine the condition of the SH tube oxide scale loading. In addition, several tube samples should be taken to check tube metallurgical condition. Results of this testing will provide guidance when the SSH sections will need to be replaced.

Estimated cost for the replacement of the inlet and outlet tubes sections of the SH have been included in Appendix A.

Superheater outlet headers typical have a design life of 30 years. Superheater outlet headers experience the highest operating temperatures and therefore are prone to creep. Creep damage is detectable by physical measurement and non-destructive testing processes. Comparing periodic measurement of the header diameter to original header specifications provides an indication if the material is experiencing swelling which indicates there is creep in the material grain structure. Replication testing is a method of non-destructive testing that will provide a macro level look at the material grain structure. Replication samples on base header material, weld connections and high stress locations will show if there is the formation of cracks in the grain structure. Material cracking can be classified into various stages or classes of creep. The lowest severity is Class 1 and the highest Class 5. Material with a creep class rating of 3 should be considered for replacement within 3 – 5 years. Class 4 or higher should be replaced at the earliest possible overhaul. A frequent monitoring program should be implemented to the material with a class rating of 3 or greater. Additional destructive testing can be done to better determine the metallurgical condition of the outlet header.

NS2 outlet header inspection and testing information was not available for review during the 2019 and 2020 life assessment. Information provided and feedback from Black Hills plant staff indicates Unit 2's SH outlet header is original and has not been metallurgical tested. Total operating hours of the SH outlet header is estimated to be approximately 194,000 hours based on an Equivalent Availability Factor (EAF) of 88.5 percent for the life of the Unit. Industry experience has seen headers operate between 250,000 to 350,000 hours with little significant degradation under base loaded conditions. With continued operation with increased cycling, this header will experience accelerated degradation. Information provided and interviews with plant staff indicates Black Hills has not performed SSH header inspections and testing.

Black & Veatch recommends performing periodic testing every 5 – 7 years to monitor the header's condition and effects of cycling. NDE testing of the SH header should include tube stubs, drain stubs, vent stubs, nozzle block, support plates and outlet piping connection. SH header replacement would be determined based on the results of this periodic testing.

Black & Veatch expects the SH Outlet header will not require replacement to safely operate until 2039.

4.1.1.4 Attemperator

The superheater steam attemperator is in the boiler link piping between the primary superheater (PSH) outlet header to SH inlet header. Attemperator borescope inspection was performed during the 2012 major outage. Results showed both the attemperator nozzle, liner and pipe body were in good condition. Normal operation requires the attemperator to be in continuous service thereby imposing long term degradation of the attemperator components. Failure of the attemperator nozzle or liner will cause major downstream damage to the SSH and turbine.

Black & Veatch recommends the attemperator pipe body including attemperator components be removed and refurbished or replaced during the life of the unit. Refurbishment lead time may dictate the choice of refurbishment or replacement. Pre-replacement borescope inspection will help to determine time to schedule the refurbishment/replacement.

Attemperator body and internals replacement costs have been included in Appendix A.

Attemperation spray control valves operate under a heavy-duty service condition thereby requiring periodic inspections and replacement of internal components. Prior to 2019, Unit 2 operated with only one spray control valve station. During the 2019 minor outage, a second (redundant) attemperator spray valve station was added.

4.1.1.5 Boiler Enclosures

Boiler enclosures include the penthouse, penetration seals, windbox, arch nose dead air space and lower furnace enclosure. These areas are not considered a part of the pressure parts but are required to be sealed from the atmosphere to provide boiler and personnel protection. It is important that these areas are routinely inspected to identify areas of overheating and leakage. These areas are vulnerable to boiler movement caused by thermal expansion. Boiler enclosure issues will accelerate with the onset of unit cycling. B&W and others inspection reports indicate these enclosures are in fair to good condition but require repair and maintenance in specific locations. Black Hills should review inspection reports to assign workorders to correct as-found conditions.

It is recommended to continue frequent maintenance inspection and repairs of the boiler enclosures.

4.1.1.6 Sootblowers

Black Hills installed a Diamond Power Intelligent Sootblower system during the 2019 minor outage. This included new bent tube panels for the water blower system. A new bent tube panel was added for the FEGT measurement probe on the 10^{th} Floor, and bent tube panels on the 8^{th} Floor were added to a water lance for opacity control during unit start up only. During the 2019 site visit, plant staff was working to optimize the sootblower program to maximize boiler cleaning efficiency and reduce effects of steam and water impingement on the boiler tubes. As of 2020 the plant has optimized the performance of the new system with continued adjustments to the system to account for changing internal boiler conditions. Sootblower inspection of various other areas have identified degradation in and around some of the sootblower wall panels and tubes in the sootblower lanes. Most of this deterioration is repairable by O&M activities.

Black & Veatch recommends continued inspection and thickness testing and maintenance of tube shields in the affected areas of the sootblower.

4.2 BOILER FUEL

4.2.1.1 Pulverizers

Black & Veatch finds the pulverizer system is in good condition. Pulverizer O&M is a mature process within Black Hills. Black Hills has a robust pulverizer maintenance program which identifies routine maintenance and capital replacement parts. The B&W 67N Roll Wheel Pulverizers are maintained annually with wear components such as the roll wheel and tables being replaced on an 8-year cycle.

Photo 4-1 B&W Pulverizers

Table 4-2 is the Pulverizer Rebuild Schedule based on recent historical and forecasted Black Hills Capital Expenditures.

Table 4-2 Pulverizer Overhaul Schedule

MILL	LAST OVERHAUL	COST	REPEAT FREQUENCY	NEXT BUDGETED OVERHAUL YEAR
A	2017	$905,000	8	2023
B	2015	$889,300	8	2026
C	2016	$905,000	7	2024
* In 2012 pulverizer work rolled up to WO 99810703. The work was complete under a lump sum contract which divided evenly among the units would have cost $33,250. In addition to the labor $61,000.00 of parts were used in the overhaul. The capital portion of the work was completed for $238,207.00.				

4.2.1.2 Burners

B&W Airejet low NOx burners were installed in spring 2007 on the NS2 boiler. These burners were B&W's latest design and NS2 was a test plant for this new design (Wygen 1 was the first to have Airejet burners installed in 2006. NS2 followed with installation in 2007.) There were minor issues with the burner's operation; however, the issues have been addressed. Periodic maintenance replacement of high wear and heat damaged components will be required to maintain proper burner performance. Black Hills budgets for burner cone replacement every 3 years. In addition, major burner repairs are planned for 2025.

The burner start-up fuel was converted from fuel oil to natural gas in 2014. Routine maintenance of the system should keep the system operating well until 2039.

A new flame scanner upgrade was installed in 2014. Capital replacement should not be necessary before 2039.

Capital replacement of the burners is not anticipated to be required by 2039.

4.2.1.3 Burner Coal Transport Piping

Leaking coal pipes create an air quality and fire hazard condition inside the main turbine and equipment building. Periodic pipe thickness and ceramic liner inspection and replacement plan should be used to replace worn pipes before a leak occurs. Pulverized coal transport pipes from the coal mills to burners were spot checked in 2016/2017 time frame. Pipe thickness and ceramic liner condition is in good shape. Black Hills will continue to perform thickness checks and inspections of ceramic lining.

4.2.1.4 Coal Bunkers

In compliance with FM Global and Black & Veatch recommendation for a coal bunker inspection and testing program, Black Hills developed and implemented an inspection and testing program for the coal bunkers in 2020.

4.3 BOILER AIR AND GAS

4.3.1 Fans

The fan system consists of the forced draft (FD), induced draft (ID) and primary air (PA) fans. The ID and FD fans are 1 x 100 percent with no redundancy making them a single point of vulnerability (SPV).

The single FD fan is a double width, airfoil bladed, centrifugal fan. The FD fan is a double inlet, single discharge design and is direct connected to a single speed induction motor. The mature and robust design of the FD fan system makes for a low probability of failure. Periodic inspection of the fan wheel and casing should be performed to keep the fan operating at its designed parameters. The FD fan is equipped with an independent lube oil unit. Routine maintenance and periodic replacement of lube oil system components should keep the fan bearing properly lubricated for reliable and long-term service. Motor drive original equipment manufacturer (OEM) maintenance recommendations should keep the electric motor operating failure free. Black & Veatch does not anticipate the replacement of the FD fan system by 2039.

The three PA fans are single width, single inlet, backward curve bladed, centrifugal fans. Each PA fan is direct connected to a single speed induction motor. Each PA fan is furnished with an inlet vane control damper and inlet and outlet isolation dampers. The mature and robust design of the PA fan system makes for a low probability of failure. Periodic inspection of the fan wheel and casing should be performed to keep the fan operating at its designed parameters. The PA fan is equipped with an independent lube oil unit. Routine maintenance and periodic replacement of lube oil system components should keep the fan bearing properly lubricated for reliable and long-term service. Motor drive OEM maintenance recommendations should keep the electric motor operating failure free. Black & Veatch does not anticipate the replacement of the PA fan system by 2039.

The single ID fan is a horizontal shaft, centrifugal type with double inlet, single discharge, and curved, backward-inclined blades designed for direct connection to an electric motor drive. The ID fan is equipped with an inlet vane damper for flow control. The mature and robust design of the ID fan system makes for a low probability of failure. The ID fan is equipped with an independent lube oil unit. Routine maintenance and periodic replacement of lube oil system components should keep the fan bearing properly lubricated for reliable and long-term service. Motor drive OEM maintenance recommendations should keep the electric motor operating failure free unless additional air quality control equipment is added to the Unit. The ID and FD fans will be rebuilt during the 2021 outage. Black & Veatch does not anticipate the replacement of the FD and ID fan system by 2039.

Both the ID and FD fan have variable inlet vanes (VIVs)with a pneumatic controller. These controllers are aged, have difficulty in controlling vane positions, and need replacement. Black Hills has budgeted to replace the ID inlet vanes controller and to upgrade the inlet damper during the 2021 outage. The FD fan controller and damper upgrade is not forecasted in the Black Hills 5-year capital budget. Black & Veatch recommends similar type replacement of the controller and damper upgrade.

Photo 4-2 Pneumatic Controller for ID Fan VIVs

Black & Veatch has included an estimated capital replacement cost of the FD controller and damper upgrade in Appendix A.

ID fan motors are reported on an 8-year cycle for major cleaning. Group 1 motors (ID and FD) were sent out in 2017 for cleaning and maintenance. No major issues were reported with the ID fan motor. NS2 has access to a spare ID and FD fan motors which are being stored in Pocatello, Idaho.

The fans wheels appear to be in good condition. Crack repairs were made on the ID fan in 2011. Additional repairs have not been identified from information provided. There are annual PM's to wash and visually inspect the fan rotors, but no NDE testing is performed to identify cracking. As a minimum, the ID fan should be NDE inspected for cracking at each minor outage. ID Fan housing repairs were made in 2020. Future repairs will be required, but fan housing replacement is not anticipated.

Black & Veatch recommends adding a PM for NDE testing of the FD, ID and PA fans and housings at every minor (4 year) outage.

4.3.2 Air Preheater

The air preheater is an Alstom vertical inverted rotating element air preheater. Black Hills has determined basket and seal replacement should be scheduled on an 8-year cycle based on a 2-year overhaul inspection. Air heater baskets were changed in 2019. Based on the current replacement schedule, cycle basket replacement should be scheduled for 2027 and 2035.

One cycle of reoccurring replacement costs for air preheater baskets and seals have been included in Appendix A.

Black Hills does a satisfactory job of maintaining the air heaters and soot blowing system. The hot end sootblowers are not used and does not appear to contribute to air preheater basket degradation.

4.3.3 Ductwork

All ductwork expansion joints were reported as original, and expansion joint work has been minimal. However, the expansion joint above the ID Fan has recently been repaired or replaced. Some erosion in the ductwork was reported, mostly around the economizer outlet, and has been repaired. The remaining ductwork sections were reported with no issues. Based on interviews and information provided, current O&M practices are adequate, and the equipment should provide safe and reliable service until 2039.

Information is not available on the condition or replacement of expansion joints on the air and gas side ducts. Periodic inspection of these expansion joints should be included in the boiler maintenance program. Fabric expansion joints have a life expectancy of 15 – 20 years if maintained properly. A detailed review of the existing expansion joints and a minimum yearly inspection of the ductwork internals is warranted.

Black & Veatch recommends implementing an expansion joint inspection PM in EAM to record inspections, repair and replacement history.

Structural components of the duct system are reported in working order, requiring only normal maintenance activities. Current O&M practices are adequate, and the equipment should provide safe and reliable service until 2039. Replacement of the minor equipment may be required for continued reliable operation.

4.3.4 Steam Coil Air Heater

Steam coil air heaters (SCAH) are original equipment. They are primarily used during the winter months of operation. Review of work order history does not identify any reoccurring problems with coil leakage. The SCAH condensate return system has had issues with maintaining proper level control. Level control issues can be corrected by focused engineering and maintenance efforts.

Black & Veatch recommends a SCAH layup program be considered during the off season to minimize internal corrosion.

With annual cycling operations, and with no identified layup program, replacement of the SCAH coils and condensate return system can be expected.

Replacement costs of the SCAH coils and condensate return system has been included in Appendix A.

4.4 TURBINE

4.4.1 Turbine

The turbine is a General Electric (GE) horizontally split, cast alloy steel symmetrical casing, single flow, axial exhaust, straight condensing machine designed for high back pressure. The internal parts of the turbine, diaphragms, packing boxes, etc. are supported at the horizontal center-line of the machine. The turbine is designed to provide extraction heating steam to two low pressure (LP) closed feedwater heaters, one deaerator, and two high pressure (HP) closed feedwater heaters. The turbine is supplied with an integrated turbine lube oil system. A motor-operated turning gear located on the side of the turbine turns the turbine rotor as required when not in operation.

No additional operating and maintenance information has been provided that would alter the 2019 life assessment analysis and recommendations.

Black Hills has performed OEM recommended turbine maintenance inspections and overhauls in the past 10 years. The more prevalent work performed has been:

- 2009 overhauls inspection - The 1st, 2nd and 3rd stage buckets heavily rubbed on inlet side, with very significant inlet side foreign object damage to vanes. Replaced first three rows of rotor buckets.
- 2012 Turbine Controls Upgrade - Upgraded Mark V system to ABB system. Multi-year project, engineering and contract release in 2011. Install during 2012 overhaul.
- 2012 Upgrade Turbine vibration monitoring equipment - Installed NS2 vibration monitoring. NS2, Wygen 1, and Wygen 2 cannot be accurately monitored by a route based mobile data collector. This will not allow data collection for balancing or problem detection. This project installed a new panel and new proximitors to allow a mobile data collector access to the vibration signal without jeopardizing the unit reliability.
- 2013 Fire Protection Turbine Generator
    - FM Global req 03-07-0071. - Fire protection installed inside T4 bearing enclosure (generator) to protect the lube oil piping associated with the bearing and instrumentation. The bearing fire protection system was converted from manual (preactiviation of system) to fully automatic (similar to Wygen 2 and Wygen 3).
- 2015 Major Diaphragm Rebuilds and Replacement
    - Many diaphragms found to have moderate to severe water cutting and other miscellaneous damage.
    - The 2nd stage diaphragm had dished downstream to where it is touching the rotor. The welds were in failure mode, with 3rd through 5th stage diaphragms having significant dishing. Installed new diaphragms just in time.
- 2017 Hydraulic Upgrades on Turbine EHC
- 2018 Turbine Controls Support (Coordinated Controls)

During the 2017 major turbine overhaul, GE submitted a list of recommendations to Black Hills for consideration. Table 4-3 summarizes GE's recommendations and Black Hills action.

Table 4-3 GE Turbine Recommendations

RECOMMENDATION	DESCRIPTION	RECOMMENDED DATE TO BE DONE
Valve, Combined Control; Seat; Connector, CV, CV Head Gasket, CV Seat	Re-stock CV seat with one that has extra stock. 194D7765P0101, Stock Connector, CV 351B2808P0001	Complete
Atmospheric Relief Diaphragm; Assembly; Atmospheric Relief Diaphragm	Replacement aluminum diaphragm should be in stock as well as the rubber shields.	Complete
Valve, Combined Stop; Assembly	A new replacement stem, connector and pins should be on hand for the next valve outage.	Complete
Diaphragm, HP; Assembly; HP Diaphragms	A new replacement stem, connector and pins should be on hand for the next valve outage.	Complete
Hood, LP; Ledge; 16th, 17th	With respect to the diaphragm it would be recommended that seal strip-type inserts be used to allow clean-up of the seal faces as well as to provide a material that would help with future diaphragm seal face erosion.	Complete
Packing Casing: Assembly; Lug, Cap Screw	Re-stock packing casing N1 G5,6,7 lug and cap screw hardware.	Complete
Packing, Shaft; Assembly; Packing Ring Modification	A full set of spare packing is not recommended at this time since it was all replaced at this outage. If no upset conditions are encountered to cause a suspect of damaged packing, the current set should last through the next outage at which time a close inspection can be performed.	Waiting for Information
Bearing, Generator Journal; Assembly; T3, T4	For future reference, in accordance to dwg 966E946, bearing; the pad bore diam = 14.029" +.002 and the resultant assembled bearing diameter = 14.022" +.002.	Complete
Valve, Combined Stop; Assembly; Actuator, Strainer	Suggested that the spare strainer be modified with the fine mesh screen kit and placed in storage for future use.	Install mesh when needed.
Rotor, HP/LP; Packing Land; 17th and 18th Stage Wheel	This area seems to incur water erosion and needs to be monitored, expect continued erosion in the future. Consider possibility that further machining may or may not be needed at the next outage, Black Hills should be being prepared at the next	To be monitored and looked at during next Outage

RECOMMENDATION	DESCRIPTION	RECOMMENDED DATE TO BE DONE
	overhaul. Note that the diameter of rotor at the packing gland for the 17th and 18th stage has changed due to the machining and should be noted for future reference if new packing is required.	
Diaphragm, LP; Assembly; LP Diaphragms	Monitor condition and progress of the erosion in the future.	To be monitored and looked at during next Outage

NS2's turbine inspection and overhaul schedule are based on the following periodicity and durations. Black Hills's next major turbine overhauls is scheduled in 2025.

Table 4-4 Outage Type

OUTAGE TYPE	OUTAGE CYCLE (YEARS)	DURATION (DAYS)
General	1	7
Minor	4	14
Major	8	30

As-found conditions of the turbine and valves during each inspection shows significate degradation of turbine and valve components. The unit appears to experience a high degree of turbine diaphragm erosion and seal rubbing. Black Hills should budget additional funds at each inspection and overhaul to cover unexpected issues. Black Hills must continue funding turbine and valve maintenance and capital replacement funding to maintain reliable operation. Increased load cycling will exacerbate degradation, therefore diligent maintenance, inspections and overhauls will be required.

GE has noted if turbine shaft degradation continues, additional machining and seal resizing will be needed. Black Hills may consider an HP turbine upgrade if required turbine rotor specifications are compromised by additional machining. As of 2020 Black Hills is not considering an upgrade.

Black & Veatch recommended a steam path audit be performed to identify the cause of high erosion and seal and packing rubbing.

The cost of the steam path audit is included in Appendix A as a separate line and only includes the cost of the audit. The intent is to perform the audit during the next scheduled turbine overhaul.

Reoccurring turbine overhauls and capital component replacement is included in Appendix A.

For information, Black & Veatch has included the estimated cost for the replacement of the rotor, inner HP cylinder and diaphragms in Appendix A.

The turbine hydraulic power control unit (HPU) is located on the ground floor in the turbine area. It contains two hydraulic fluid pumps, hydraulic fluid reservoir, two hydraulic fluid heat exchangers, the electric trip solenoids, electric trip solenoid lockout solenoids, hydraulic pressure switches and gages, and the transfer and filter unit motor (TAFM). The hydraulic fluid pumps pressurize the turbine hydraulic system to provide the driving force to open the main steam stop valves and move the main steam inlet control valve.

The HPU system does not operate properly due to age of pressure switches and other issues with the system. Hydraulic oil temperature is difficult to regulate causing overheating of the hydraulic oil during automatic generation control (AGC). The HPU system needs evaluation to identify the system issues and provide resolution.

Black & Veatch recommends evaluating the HPU system to identify reliability issues and determine appropriate solutions.

4.5 GENERATOR AND EXCITER

Black Hills has performed OEM recommended generator maintenance inspections and repairs in the past 10 years. The more prevalent work is noted below.

In 2014, generator rewind preliminary work was performed. This included pulling the rotor for stator rewind measurements.

During the 2015 outage the generator rotor was removed, inspected and tested. The generator stator was inspected while the rotor was out. No issues were identified.

In 2017, the generator field was removed and sent to Ethos in Farmington, NM for testing and inspection of suspected damage to insulation caused by a previous incident with a transformer. A full rewind of the generator field was performed. Testing of the generator stator revealed loose wedges in the center core, and a full rewedging of the stator windings was performed by Ethos personnel.

Partial arc monitoring has been installed on the stator, enhancing Black Hills's ability to monitor future generator performance. Staff noted and the forecasted capital budget shows the stator rewind is being planned during the 2025 Outage. Long lead time parts are being ordered to facilitate the scheduled outage.

With the rewind and scheduled stator rewinding, the generator should perform well until 2039. Routine testing, inspection and outage maintenance repairs must be employed to maintain expected service life.

Generator protection relays are used to protect the generator from on-line electrical disturbances which could critically affect the health of the generator. The protection relays have been replaced within the last 6 years. Black & Veatch does not anticipate the need to replace the generator protection relays by 2039.

The excitation system employs a main exciter alternator and fuse/diode wheel, all furnished by GE on a common shaft coupled to the generator field. Excitation current is transmitted from the main exciter armature to the fuse/diode wheel and then to the generator field by means of conductors internal to the shaft. Voltage regulation is accomplished by controlling the main exciter field current with the static voltage regulator. The static voltage regulators are mounted in a free-standing, metal-enclosed cubicle.

The exciter was replaced in 2017. This is expected to provide reliable service until 2039.

4.6 HIGH ENERGY PIPING

The Main Steam System conveys HP superheated steam from the SH outlet connection of the steam generator, through a single main steam header, to the turbine combined stop and control valve. The stop/control valve is located between the boiler and the turbine. The main steam piping is constructed as 12.75" OD with 1.361" minimum wall thickness pipe. The pipe material is ASTM A335 P22 chrome-moly steel. The main steam line is constructed with six (6) diameter radiused bends. A drain pot (or drip leg) is provided for water removal from the main steam line. The drain pot is located at the lowest point of the system in the horizontal run prior to the turbine stop/throttle valve, and a drain line from this drain pot is routed to the steam generator blowdown tank. One safety valve and one power-operated electromatic relief valve are provided for system overpressure protection. These valves are installed on piping furnished with the steam generator. The vent stacks from these valves are routed to the steam generation building roof.

In fossil and combined cycle plants, high-energy piping (HEP) systems, such as the main steam (MS), hot reheat (HRH) and cold reheat (CRH) piping, are critical in terms of personnel safety and overall plant longevity. Because of the potential for long-term degradation of piping system materials, and the undesirable/catastrophic consequences of piping system failures, these systems require a dedicated and periodic inspection, testing and analysis program. A complete HEP evaluation includes hot/cold hanger walkdown and a battery of non-destructives tests at high stress locations of the main steam and hot reheat pipeline from the boiler outlet to turbine inlet. The evaluation should include computer modeling of the MS and HRH pipe system to identify high stress locations and potential hanger support deficiencies.

Stress analysis and thickness testing was performed by EAPC Industrial Services in 2017 and documented in report No. 201723370. EAPC provided hanger walkdown, pipe stress modeling and thickness testing of selected pipe locations. The study does not provide metallurgical analysis for creep and inspection for cracking. Metallurgical and NDE testing should be performed to provide creep analysis of pipe material along with weld conditions at high stress attachment locations. A complete HEP evaluation program should include both elements of evaluation.

Black & Veatch's unit walkdown did not identify any immediate concerns in the condition of the support system. The pipe and attachments are not visible and must have insulation and lagging removed in selected areas to properly inspect and test.

In 2019 FM Global recommended Black Hills develop a formal high energy pipe inspection program. Black & Veatch concurs with FM Global in developing a HEP metallurgical and NDE evaluation program. Execution of the MS and HRH steam piping evaluation program is recommended at the next appropriate outage.

Cost estimates for developing and performing a HEP metallurgical and NDE evaluation is included in Appendix A .

4.7 AUXILIARY EQUIPMENT / BALANCE OF PLANT

4.7.1 Condenser and Circulating Water

4.7.1.1 Air Cooled Condenser

NS2 uses a GEA Heat Exchangers Inc. (GEA) "A" tube air cooled condenser (ACC) initially commissioned in 1995, with a two (2) cell summer peak extension added in 2001. In 2007, a third row was added (5 cell SPX single row tube) totaling 17 cells which is intended for summer operation, as shown in Photo 4-3. The ACC had been experiencing leaks in the upper tube to tube sheet area of the original ACC, mainly in the first bay after the risers and the bundles just after the "D" section.

Photo 4-3 ACC with 3rd Row Configuration

In 2020 Black Hills replaced all the ACC tube bundles and headers (project no. 10057418). Additionally, Black Hills has implemented new operation procedures which will improve offline and cold weather layup. The new ACC bundles should provide reliable service until 2039.

Early finding of erosion into the base metal with no explanation for the cause of erosion was noted. The shiny area is not flash rusting but rather etching into the base metal. The main duct downstream of the turbine outlet is also showing a degrading effect to the duct inside surfaces.

Prior to the replacement of the ACC tube bundles, condensate returning from the ACC contains substantial amount of iron which is carrying over to the boiler. Iron carryover was found to be a product of flow accelerated corrosion (FAC) due to feedwater pH. Black Hills believes the root cause of the corrosion problems was poor water chemistry in the early years of operation. Water chemistry has much improved with little corrosion now observed. In 2019 an iron filter to collect any iron carryover from the ACC was installed (project no. 10051960). Black Hills will continue monitoring the ACC water chemistry and equipment condition addressing issues as needed.

ACC fan motors have been upgraded to VFD motors. Originally there were 10 fans using Allen Bradley 1336 VFD's, they were upgraded to ABB drives in 2014. In 2016 the two remaining constant speed fans were upgraded to ABB VFD's. Brennan Engineering performed the control work for the VFD install, they are all tied in to the ABB DCS system. The motors are equipped with vibration monitoring which are monitored in the control room. These motors and VFD's should provide reliable operation with routine maintenance and cleaning until 2039.

4.7.2 Feedwater

The boiler feed system supplies feed water from the deaerator storage tank to the economizer inlet through the two HP feedwater heaters and is considered a part of the HEP system. Desuperheating spray water is also supplied to the superheat desuperheater for steam temperature control. The boiler feed system includes two motor driven boiler feed pumps and two HP heaters.

4.7.2.1 Boiler Feedwater Pumps

Two nominal full capacity, multi-stage, centrifugal type, constant speed, electric motor driven boiler feed pumps are provided. Each feed pump is provided with a main (shaft driven) and auxiliary (motor driven) lube oil pump. Each feed pump is provided with mechanical seals, with seal flush water supplied by the condensate pumps.

Feedwater pumps A and B have been overhauled in 2018 and 2019, respectively. Both boiler feed pumps are scheduled for their next capital overhaul in 16 years. Black Hills stocks a spare motor for the auxiliary pump.

Capital refurbishment costs for one overhaul of the two boiler feed pumps is included in Appendix A.

4.7.2.2 Feedwater Heaters

Two horizontal U-tube type, HP feedwater heaters equipped with stainless steel tubes and integral desuperheating and drain cooler zones are provided.

In 2019 interviewees noted the HP and LP feedwater heaters have not been eddy current tested to identify thinning tube material. No major maintenance has been performed on the feedwater system throughout the history of operation. Information reviewed does not show any feedwater heater and associated system equipment deficiencies. As of 2020 eddy current testing has not been performed. Testing should be planned for the next major outage to baseline tube and shell condition. Provided the shell and tubes are in good condition, the feedwater heaters should operate reliably until 2039.

4.7.2.3 Feedwater Piping

FAC is a phenomenon which occurs in HP boiler feed water piping and extraction steam piping systems. FAC causes severe corrosion erosion on the internal surfaces of piping and valves. It occurs mostly on carbon steel, which has little resistance to this corrosion mechanism and can cause catastrophic failure of the pipe or valves, resulting in personal injury or death. FAC analysis of the HP feedwater piping will locate and identify high risk areas in the piping system.

NS2 performed a stress analysis of the boiler feed pump suction and discharge piping in 2012 and 2017 taking thickness measurements at select pipe descriptive locations and model node points. Black & Veatch was unable to determine if the descriptive location (2012 report) and model node points (2017 report) are the same locations. Information provided shows limited FAC inspection performed on the feedwater piping system. Black Hills clarified the 2017 inspection covered only a portion of the total FAC test points included in their FAC program. All test points are inspected on a rotating basis over a period of time. Black Hills FAC program is approved by FM Global.

4.7.3 Deaerator and Deaerator Storage Tank

The power industry has long known of the serious safety concerns of cracking in deaerator (DEA) welds. In some instances, shell cracking has resulted in small leaks; in others, complete failure has occurred. In response, technical advisories and guidelines were prepared outlining the necessity of internal weld inspection and recommending methods for inspection and repair. Advisory statements of this type have been issued by Technical Association of the Pulp and Paper Industry (TAPPI), the National Association of Corrosion Engineers (NACE), and The National Board of Boiler and Pressure Vessel Inspectors.

TAPPI and FM Global recommend the DEA and DEA storage tank to be inspected on a 5-year basis for cracks and other damage. Welds are NDE tested at a rate of 20 percent every five years, with full coverage after 25 years of service. The last inspection for the NS2 DEA was in 2012. Inspection results showed no issues with the tested welds. The next full inspection will confirm overall DEA and storage tank health. Black & Veatch anticipates these vessels will provide reliable service until 2039.

Currently, Black Hills performs 20 percent testing each outage, covering 100 percent of all welds after 5 inspection cycles. This process is acceptable to FM Global.

4.7.3.1 Closed Cooling

The auxiliary cooling water system supplies condensate-quality cooling water to plant heat exchangers. The auxiliary cooling water is circulated in a closed loop through the auxiliary cooling tower (ACT) by two centrifugal auxiliary cooling water pumps. An elevated auxiliary cooling water head tank is provided for the necessary static head.

Black & Veatch observed the closed cooling system to be in good condition, except for the ACT located outside on the east side of NS2 as shown in Photo 4-4. From both information provided and through interviews, the ACT was identified as being a high maintenance item with reduced capacity from the original design. The reliable operation of the ACT is critical to the safe operation of equipment requiring adequate closed cooling water, therefore swift action must be taken to maintain ACT reliability.

Photo 4-4 Old Auxiliary Cooling Tower

Black Hills will be replacing the ACT in 2021. The new ACT should provide reliable service until 2039.

4.7.3.2 Water Treatment

Overall, the water treatment system is in good condition. Water treatment supply and storage capacity are not an issue during startup. NS2 has one condensate storage tank with a capacity of 70,000 gallons. The water treatment and storage capacity are enough for unit startup. Information provided and staff interviews did identify a bottle neck in the condensate supply pipe from the condensate storage tank to NS2 and Wygen 2 fill pump when there is a simultaneous unit startup. The pipe is an under sized pipe (2 ½”) and needs to be enlarged.

The original cation/anion demineralization system was replaced in 2008 with two trains of reverse osmosis (RO) filtration system capable of 150 GPM per train. The RO system upon commissioning produced product water with conductivity < 1.0 µS out of both RO trains before the mixed resin bed polishers. It is currently producing water > 10 µS before the mixed beds. This is not causing any quality issues for boiler make-up water, as the mixed resin beds reduce the conductivity down to <0.1 µS. This does however cause the mixed beds to regenerate more frequently. Currently there is no concern for boiler make-up water quality. Black Hills is working on a solution to this issue.

If NS2 begins to cycle on/off, extended startup time will require additional water capacity. Additional treatment and storage capacity may need to be addressed for future cycling operation. Water treatment capacity should be addressed by a separate study.

Returning condensate from the ACC has a high iron content. In 2019, Black Hills installed an iron filtration system in the condensate return system to reduce iron. The addition of these filters will aid in water cleanup if NS2 begins cycling service.

4.8 ELECTRICAL EQUIPMENT

4.8.1 Generator Step Up Transformer

The Generator Step Up (GSU) transformer is rated at 90/120/150 MVA, ONAN/ONAF/ONAF, 69KV/13.8KV. The GSU was replaced in 2012 as a result of a catastrophic failure from overheating.

The new transformer has been designed with additional capacity (105 to 150 MVA) to eliminate overheating. The GSU transformer should perform as designed with no issues until 2039. The failed transformer was repaired and is available as a spare.

Currently the only issue found with the GSU transformer during interviews with plant personnel was an inoperable and leaking hydrogen monitor. Black Hills will remove and not replace the monitor. Black Hills has chosen to monitor hydrogen accumulation based on quarterly oil samples. Black & Veatch reviewed the 2015 GSU testing reports conducted by Alternative Technologies, Inc. and the 2017 maintenance report conducted by Electro-Test & Maintenance, Inc. The test reports indicate the transformer is in good overall condition. The oil quality and dissolved gases are within acceptable concentrations, while the transformer connections, bushing, enclosure and insulation are also in good condition. Black & Veatch agrees with Alternative Technologies, Inc. in that re-testing should be conducted annually.

Black & Veatch recommends continued routine maintenance and yearly GSU transformer testing to monitor the active and spare GSU transformers condition.

4.8.2 Auxiliary Transformers

NS2 has two originally installed auxiliary transformers. The main auxiliary transformer (MAT) is connected to the generator 13.8KV bus and the reserve auxiliary transformer (RAT) is connected to the 69KV switchyard. Both transformers are connected to the main 4160V switchgear. The RAT is the only transformer which can supply power to the 4160V bus during start-up. Once the generator is synchronized, power can then be routed to the station bus through the MAT. The start-up power supply scheme to the 4160V bus makes the RAT a single point of vulnerability and therefore a critical piece of equipment. Data reviewed and interviews with plant personnel in 2019 indicate there are no issues with either auxiliary transformers. No additional information was available during the 2020 life assessment. The MAT and RAT should perform as designed with no issues until 2039.

Black & Veatch understands the criticality of the RAT and recommends that Black Hills consider purchasing a spare RAT. As a minimum, Black Hills should locate a similar transformer in their system or find an available transformer externally to lease as an insurance measure.

Estimated costs for the purchase of a spare transformer has been included in Appendix A.

4.8.3 Medium Voltage (4160V) Switchgear and Relays

The medium voltage switchgear and motor starters were manufactured by Westinghouse in 1993/1994. Black & Veatch reviewed available 4160V switchgear data and the most recent 2017 maintenance and inspection reports available. Black & Veatch interviewed plant personnel in 2019 and found that spare parts are becoming difficult to procure as the switchgear is becoming obsolete. Interviews also found that an arc-flash study for the switchgear is due in 2019, and the 4160V relays were upgraded in 2017 to microprocessor-based relays by Schweitzer Engineering Laboratories, Inc. (SEL). The plant indicated there are no issues associated with the relays. Plant electricians perform the maintenance of the switchgear. A remote racking device is available; however, no mandatory policy is in place to require its use. Given the age of switchgear, interlocks to prevent racking in closed breaker may not be present / working. While not a life assessment issue, Black & Veatch recommends implementing a policy for its use as a safety initiative. In general, the 4160V switchgear and motor starters are in good condition and should provide reliable service in the short term. In the long term, Black Hills should begin planning for the replacement of the switchgear during an appropriate planned outage. The 4160V switchgear is a critical part of plant operation, and as the switchgear becomes obsolete spare parts will no longer be available. Replacement of this equipment requires long lead times. Estimated lead time to engineer, purchase and install this electrical equipment is 18 – 24 months. Installation of the equipment will require an extended outage of 4 – 6 weeks where demolition and installation will need close coordination with other outage activities because of the impact to other outage work during loss of major electrical circuits.

No additional information has been provided in the 2020 Life Assessment therefore Black & Veatch recommends replacement of the medium voltage (4160V) switchgear.

Medium voltage (4160V) switchgear capital replacement costs have been included in Appendix A.

4.8.4 480V Secondary Unit Service Switchgear and Motor Control Centers

The 480V secondary unit service (SUS) switchgear and motor control centers (MCC's) were manufactured by Westinghouse in 1993/1994. Black & Veatch reviewed available 480V SUS switchgear and MCC data and the most recent maintenance and inspection reports available. Black & Veatch also interviewed plant personnel. Interviews found that an arc-flash study for the SUS switchgear and MCC's was due in 2019 and the plant electricians perform routine maintenance of the starters and breakers in the equipment. Interviews found the availability of spare parts for the MCC's is not an issue; however, spare parts for the SUS switchgear is becoming an issue. Black Hills should start planning for the replacement of the SUS switchgear as they are the same vintage as the 4160V switchgear and will become obsolete. SUS switchgear replacement can be performed at the same time as the 4160V switchgear replacement. As stated in the 4160V switchgear section, replacement of this equipment requires long lead times. Estimated lead time to engineer, purchase and install this electrical equipment is 18 – 24 months. Installation of the equipment will require an extended outage of 4 to 6 weeks where demolition and installation will need close coordination with other outage activities because of the impact to other outage work during loss of major electrical circuits. Information provided in 2020 shows Black Hills replaced the SUS 13 transformer during 2020. No information was provided on the reason for replacement.

No additional information was provided in the 2020 Life Assessment therefore Black & Veatch recommends replacement of the 480V SUS switchgear.

480V SUS switchgear replacement costs have been included in Appendix A.

4.8.5 Automatic Voltage Regulator Control Panel

Interviews with plant personnel found the NS2 auxiliary control panel/automatic voltage regulator (AVR) control panel was refurbished in 2019. The obsolete components inside the control panel were replaced with updated components. No new functionality was added during the refurbishment. The refurbished AVR control panels should perform as designed, with no issues using proper maintenance, until 2039.

4.8.6 Arc – Flash Safety

Black & Veatch also recommends Black Hills exercise due diligence in electric equipment safety and produce mandatory safety procedures when working on electrical equipment. Training for plant O&M personnel by a qualified certified instructor in arc-flash safety should be given to all O&M personnel in accordance with National Fire Protection Association (NFPA) 70E. The purpose of NFPA 70E®, Standard for Electrical Safety in the Workplace®, is to provide a working area for employees that is safe from unacceptable risk associated with the use of electricity in the workplace. NFPA 70E establishes safety processes that use policies, procedures, and program controls to reduce the risk associated with the use of electricity to an acceptable level. It is imperative that everyone in the plant recognizes and understands the cause and effect of an arc flash. Specific arc flash training should be conducted to include preventative measures and proper personal protective equipment necessary for each hazard level. Black Hills should have their O&M procedures pertaining to MCC's and switchgear reviewed and modified by a qualified and certified consultant who is familiar with the equipment and its current condition and NFPA 70E standards.

Black & Veatch recommends no maintenance be performed on 480 V MCC and 4160V switchgear buckets and breakers while on line. Switching on/off the equipment should be done by remote control switching. If the equipment is not equipped with remote switching capabilities, then all safety precautions must be implemented for personnel protection in accordance with NFPA 70E.

Black & Veatch recommends that non-essential personnel access be restricted near or entering MCC and switchgear rooms or enclosures during online operation. Areas which are designated as general access locations, such as electrical equipment rooms and walkways between 480V and 4160V equipment, should be restricted, allowing only essential O&M personnel during electrical maintenance functions. If electrical work is being performed in the area, O&M personnel should wear properly rated flash protection personal protective equipment (PPE) in accordance with NFPA 70E for the distance working from the electrical equipment.

Black & Veatch recommends the NS2 arc-flash study be updated along with refresher training and Black Hills O&M procedures updated to the latest version of the NFPA 70E standards.

The costs for arc flash study update, refresher training and O&M procedure updates are included in Appendix A.

4.8.7 Large Motors

There are no issues with large motors. There are spare motors stored in various Black Hills inventory locations for all critical equipment.

4.8.8 Batteries

The uninterruptable power supply (UPS) batteries were last replaced in 2010 with the battery charger and inverter being replaced in 2016/2017. Black Hills replaced the UPS batteries in 2020. "PowerSafe G" type batteries purchased for NS2 have an expected life of 20 years. It is expected these batteries will not need to be replaced before 2039. The charger/inverter should be scheduled for replacement after 10 years of service.

Photo 4-5 UPS Batteries

4.9 CONTROLS

4.9.1 Balance of Plant Distributed Control System

Black & Veatch reviewed the information provided on the distributed control system (DCS) and the information provided during the 2019 interviews. After reviewing the information and finding the site has ABB DCS products, Black & Veatch followed up with ABB on providing system life-cycle information in relation to the ABB DCS equipment installed at the site. In discussions with ABB, they provided a lifecycle status of the Harmony System Overview. A 2019 summary of the information provided by ABB is in Table 4-5.

Table 4-5 ABB Harmony System Overview

Harmony System Overview					
System Description		**Lifecycle Status**	**Support Status**	**Comments**	**Recommendation (Priority to Evolve)**
Cabinet Power Supplies	Symphony Modular Power System (MPSIII)	GREEN Active	GREEN OK	Latest Power System	No Action Required
System Communication	INFINET	GREEN Active	GREEN OK	Active-phase replacements are available for all installed communication equipment.	1 to 5 Years
System Communication	Remote I/O Connection	GREEN Active	RED Evolution Recommended	RIO based upgrade kit or IOR800 with S800 I/O	1 to 3 Years
Controllers	Bridge Controllers (BRC)	GREEN Active	GREEN OK	The BRC-410 controllers are Active.	No Action Required
I/O	Network 90 I/O	RED Limited	GREEN OK	Most Net 90 I/O modules have active direct replacements. Evolution recommend for DSM05's and ASM modules.	1 to 3 Years
I/O	INFI90/ Symphony Rack I/O	GREEN Active	GREEN OK	While some installed INFI90 Rack I/O modules are in the Limited phase, Active-phase direct-replacement modules are available.	No Action Required
I/O	Rotating Machinery Rack I/O	YELLOW Classic	GREEN OK	The CM11 offers a functional equivalent	1 to 3 Years
I/O	S800 I/O Modules	GREEN Active	GREEN OK		No Action Required
I/O	Network 90 Termination Units	RED Limited	RED Evolution Recommended	Most Net 90 Termination Units have Active direct replacements. Evolution recommended with I/O modules.	1 to 5 Years
I/O	Infi90 Termination Units	GREEN Active	GREEN OK		No Action Required

Lifecycle Status	Description
Active GREEN	Product Actively Marketed, Sold and Supported
Classic YELLOW	Product Sold and Supported; Newer Technology Product Available
Limited RED	Product Supported; not Actively Marketed and Sold
Obsolete BLACK	Best Effort Support Only

The ABB lifecycle summary and the information provided by the customer show the plant has the ABB Network 90 Termination Units and I/O. Due to the age of this equipment and generation of this equipment, an upgrade strategy should be created on how to update this equipment. The information provided shows the control room equipment was upgraded in 2013. This information also indicates a planned upgrade in 2020. We assume this upgrade is because of the Microsoft product lifecycle and cyber security solutions. If the upgrade has not been purchased, a further review of the ABB upgrade should be performed. The major item for review is how long ABB and Microsoft/others will support the new hardware and software from the time it is installed. Black Hills should consider product lifecycle, with care and understanding when upgrading with a product that may be half way into its product lifecycle. Black & Veatch recommends Black Hills evaluate all installed DCS hardware including HMI and network equipment to be North American Electric Reliability Corporation (NERC)-Critical Infrastructure Protection (CIP) compliant and fully supported by Microsoft Windows.

4.9.2 Miscellaneous Programmable Logic Controllers

The coal pulverizers use the Allen Bradley SLC 5/05 programmable logic controller (PLC) for control. Most of the SLC 5/05 platform is in the active mature lifecycle status. This means the product is fully supported, but a new product or family exists. Due to future obsolescence, these PLCs should be upgraded with a new PLC or brought into the DCS with a DCS upgrade. This has been identified by the site and the upgrade is currently forecasted for 2020 or 2021. Replacement of this control system will be required for continued operation in the future.

The water lance system uses the Direct Logic 205 PLC with the DL240 model CPU. The Direct Logic 205 PLC can still be purchased and supported, but the DL240 CPU has been retired. This PLC should be upgraded with a new PLC or brought into the DCS with a DCS upgrade. This has been identified by the site and the upgrade is currently planned for this year.

The waste ash silo baghouse and pug mill systems use Allen Bradley SLC 5 PLCs. The waste ash silo baghouse has an SLC 5/03 and the pug mill has an SLC 5/04 PLC. Most of the SLC 5/04 and SLC 5/03 platform is in the active mature lifecycle status. This means the product is fully supported, but a new product or family exists. Due to future obsolescence, these PLCs should be upgraded with a new PLC or brought into the DCS with a DCS upgrade. This has been identified by the site and the upgrade is currently forecasted for 2020.

The RO water system uses an Allen Bradley Compact Logix L30ER PLC. The 1769-L30ER controller is in the active lifecycle status. This means that the product is the most current offering within the product category. Due to this, an upgrade is not recommended at this time. Additional follow-up with Rockwell Automation on the lifecycle of this platform may be warranted in the future.

The powered activated carbon (PAC) silos use the Allen Bradley Compact Logix L32E PLC. The Compact Logix L32E PLC is in the end of life lifecycle status, with a discontinued date of 12/20/2020. This means the discontinued date has been announced, and clients should execute migrations and last time buys. Due to this, these PLCs should be upgraded with a new PLC or brought into the DCS with a DCS upgrade.

The amended silicates silo uses the Allen Bradley Compact Logix L43 PLC. The Compact Logix L43 PLC is in the end of life lifecycle status, with a discontinued date of 06/30/2020. This means the discontinued date has been announced, and clients should execute migrations and last time buys. Due to this, these PLCs should be upgraded with a new PLC or brought into the DCS with a DCS upgrade.

The FPS ignition system uses the Allen Bradley MicroLogix 1200 PLC. We were not provided the model of the MicroLogix 1200 PLC used in NS2, but most of the platform is in the end of life lifecycle status, with a discontinued date of 02/28/2021. This means the discontinued date has been announced, and clients should execute migrations and last time buys. The model number of the PLC should be provided to Rockwell Automation for them to provide a lifecycle status. Due to the age of this PLC, and since most of the platform is at the end of life lifecycle status, it should be upgraded with a new PLC or brought into the DCS with a DCS upgrade.

Appendix A includes a cost estimate for the replacement of the control systems.

Depending on the system, the replacement of the controls will take an extended downtime period and should be conducted in coordination with a major outage. A further study and/or information would be required to provide firmer pricing. Examples of required information would be control system vendor, I/O count, current installation details, etc.

Black Hills plans to perform DCS separation work to comply with NERC-CIP cyber security regulations. Capital funds have been allocated in Black Hills five-year budget forecast in 2022 and 2025. Black & Veatch did not include estimated costs for DCS separation or NERC-CIP adherence in Appendix A.

4.10 ENVIRONMENTAL – AIR POLLUTION CONTROL EQUIPMENT

4.10.1 Air Quality Control System

Black Hills NS2 is operating under emissions permit Chapter 6, Section 3 Operating Permit 3-2-158-1 dated October 29, 2013. The permitted limits and actual emissions provided by Black Hills are summarized in Table 4-6. All actual emissions are below the permitted limits.

Table 4-6 NS2 Air Permit Limits

PERMITTED LIMITS	ACTUAL EMISSIONS	PERMITTED LIMITS	ACTUAL EMISSIONS
Opacity 20% 6 min block limit	1% actual	NOx 299.0 lb/hr 30DRA limit	165.0 lb/hr actual
Opacity 5.0% 24 hr block limit	1% actual	Hg 1.2 lb/TBtu 30DRA limit	0.2 lb/TBtu actual
SO_2 0.20 lb/mmBtu 3 hr block limit	0.09 lb/mmBtu actual	CO 0.15 lb/mmBtu limit	0.08 lb/mmBtu actual
SO_2 203.0 lb/hr 3 hr block limit	100.0 lb/hr actual	CO 152.0 lb/hr limit	81.0 lb/hr actual
SO_2 0.17 lb/mmBtu 30DRA limit	0.09 lb/mmBtu actual	PM 0.02 lb/mmBtu limit	0.004 lb/mmBtu actual
NOx 0.23 lb/mmBtu 30DRA limit	0.16 lb/mmBtu actual	PM 20.0 lb/hr limit	5.0 lb/hr actual

4.10.2 Particulate Removal System

The particulate removal system consists of one (1) electrostatic precipitator (ESP), fifteen (15) ESP hoppers, three (3) dosing valves, twelve (12) rotary feeders, three (3) air slides, three (3) ash surge bins, two (2) penthouse blowers, two (2) aeration blowers, and two (2) air slide fans. The ESP is located downstream of the circulating dry scrubber (CDS) outlet and upstream of the ID fans which is interconnected with ductwork. The ESP removes solid particulate from the flue gas stream produced from combustion of coal in the boiler and material carried over from the CDS vessel in the sulfur dioxide (SO_2) removal process. The material captured in the ESP on collector plates until the material is dislodged via a rapping system is temporarily stored in the ESP hoppers where it is then dispensed to the air slides either back to the CDS or to the waste ash surge bins. In recycle mode, a portion of the captured material is fed back into the scrubber via the air slides and dosing valves. All other material captured by the ESP is directed to the fly ash and flue gas desulfurization (FGD) Solids System. Each first-field ESP hopper is provided with an overflow pipe that discharges to the waste ash surge bins.

Based on the data provided by Black Hills, the actual particulate matter emissions are below the permitted limits as summarized in Table 4-6. This indicates the ESP is currently in a condition that it is still removing particulate matter to be in compliance with the emission permit.

As a historical perspective, there were significant corrosion issues in the ESP during the first few years of operation. In 1998, NDE was performed on the ESP internals and material test coupons were installed in the corroded areas to establish corrosion baselines. In 1999 and 2000, significant NDE testing was performed on the ESP internals. Corrosion was found in several locations in the ESP due to the original brine injection system which has since been decommissioned. Due to the corrosion found on some of the collecting surfaces in the ESP, additional collecting surfaces were purchased and installed in 1999. Following 1999, more NDE testing was performed in 2000 with similar corrosion reported as the previous years. In 2014, the first two collection fields were replaced.

Several ESP assessment and repair projects have been recorded in the previous capital and projects log for the 2012 to 2017 time frame. No additional information from the inspections performed from 2012 to 2020 was available. However, it is recommended the inspection and testing program continue on a yearly basis.

The air slides were reported in good shape with a few areas reporting higher wear zones that are being replaced as needed. The air slides see increased wear from both the hydrated lime silo were material directly drops onto the air slides and where the ash overflow lines from front line of ESP hoppers discharge to the air slides. The air slide dosing valves have been replaced in 2012 and were reported as working well. Rotary feeders from the ESP hopper discharge were reported needing replacement in the very near term. The rotary feeders are original OEM equipment and are at the end of their useful life.

The ESP transformer rectifiers (T-R) were partially upgraded in 2018 to a 3-phase high frequency power supply (HFPS) system. Other T-Rs remain as the original single-phase system. T-Rs for fields 1 through 3 have been upgraded to 3 phase HFPS. T-Rs for the 4th fields are a split between new 3 phase HFPS and original single-phase system. T-Rs for fields 5 through 10 are the original single-phase system.

All other equipment in this system was reported in working condition with only normal maintenance activities. Based on interviews and information provided, replacement of the minor equipment indicated above should be considered for continued reliable operation.

Continued yearly inspections are suggested for the ESP during a major outage. Additionally, NDE survey of the ESP internals is recommended, with a structural review of the ESP if any of the NDE survey results show concerning material loss.

Cost estimates for yearly ESP inspections, NDE survey of ESP internals, and structural review has been included in Appendix A.

4.10.3 Desulfurization System

The desulfurization system consists of one (1) CDS, one (1) hopper delumper, two (2) cooling water pumps, and one (1) cooling water tank. The CDS vessel is located downstream of the air heater outlet and upstream of the ESP inlet which is interconnected with ductwork. The CDS vessel removes SO_2 from the flue gas by chemical reaction between hydrated lime ($Ca\ (OH)_2$) and SO_2. Cooling water is injected into the CDS to facilitates the chemical reaction between $Ca\ (OH)_2$ and SO_2. Additionally, cooling water is injected into the CDS to control the flue gas temperature leaving the CDS. The cooling water system consists of one (1) 7,600 gallon (operating volume) cooling water tank, two (2) 100 percent cooling water pumps, two (2) primary operating spray nozzles, and associated piping and valves.

Neil Simpson 2 is operating under emissions permit Chapter 6, Section 3 Operating Permit 3-2-158-1 dated October 29, 2013. Based on the data provided by Black Hills, the actual SO_2 emissions are below the permitted limits as summarized in Table 4-6. This indicates the CDS is currently in a condition that it is still removing SO_2 to be in compliance with the emission permit.

As a historical perspective, there were significant corrosion issues in the CDS vessel during the first few years of operation. In 1999 and 2000, significant NDE testing was performed in the CDS vessel. Significant corrosion was found in the CDS spray cone area and above up to the expansion joint. The 1999 overhaul of the CDS external stiffeners were added around the conical section of the scrubber vessel due to concerns with structural integrity. During this timeframe, significant testing was performed using test coupons of various materials welded to the inside of the CDS vessel to determine rates of corrosion on materials other than the carbon steel the CDS vessel was constructed. Additional CDS vessel corrosion control methods considered were wallpapering the inside of the CDS vessel with C276 or stainless steel, internal epoxy coating inside the CDS vessel, and internal ceramic lining of the CDS vessel. In the 1999 timeframe, Black Hills accepted an internal epoxy coating from the OEM, Environmental Elements Corporation, in lieu of a C276 wallpapering. In 2000 the internal Ceilcote lining was found to have failed. Black Hills has since replaced ½ of the CDS wall liner in 2019 with the remaining portion to be replaced in 2021. Replacement material is AR-400 for improved wear.

In 2011, inspections by Black Hills engineers revealed what was reported as severe corrosion in the venturi tubes of the CDS vessel. In the 2012 outage, all venturi tubes were replaced and the walls of the CDS were patched. A condition assessment was performed on the CDS and wall thinning was found. Plans for future CDS sidewall and cone repair/replacement was suggested in a field report to be performed in a future outage. Additional CDS vessel repairs due to corrosion appear to have taken place in the 2013 – 2014 timeframe based on the capital project log. No additional reports were available to assess the condition of the CDS vessel.


2011 photo of the venturi corrosion

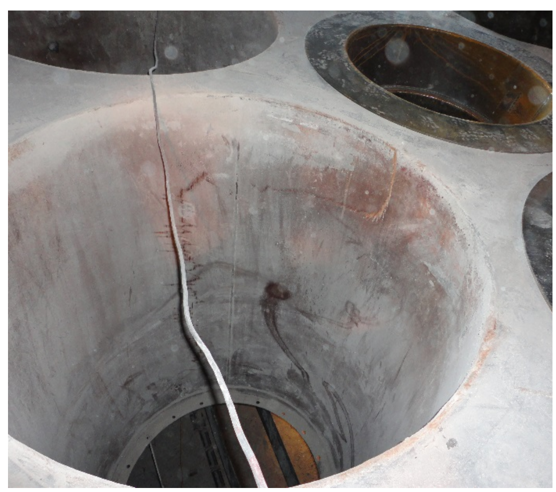
2011 photo of the venturi tubesheet with venturi tube removed

Photo 4-6 NS2 CDS Venturi Condition

Additional testing was performed in 2012 in the CDS vessel cone section and cylindrical section with the results in Figure 4-1. Significant wall losses were found as shown in Figure 4-1. Previous reports indicate the minimum required shell thickness for the CDS vessel of 0.144” is acceptable, but this should be confirmed in a structural review. It is suggested an NDE survey be performed over the entirety of the CDS vessel and a structural review be performed using the results of the NDE survey. Any recommendations from the structural review should be made.

Material buildups of ash and hydrated lime mixed with water and then dried to "concrete" that form and grow on the internal CDS vessel walls have occasionally occurred. The latest material buildup occurred in 2018 and required an outage and specialty contractor to remove the material buildup with dynamite. The cause for the material buildup in 2018 was mostly attributed to malfunctioning water spray nozzles that were wetting the internal walls of the CDS, which in turn caused material buildup. The valve and piping arrangement of the CDS cooling water system have been modified to some extent from the original design shown on piping and instrument diagram 18839-2CCC-M2143A. Cooling water pump suction strainers have been removed, the spray lance test station has been removed, and the secondary cooling water spray header has been taken out of service. Biological material (black sludge) and sand in the cooling water tank have been reported. Without suction strainers, the biologicals and sand have made their way into the pumps and piping system. This material then travels to the CDS spray nozzles, causing spray nozzle plugging and ultimately material buildups on the scrubber internal walls.

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CIRCULATING DRY SCRUBBER

Color Code
0.250" & Above - Blue
0.187" - 0.249" - Green
0.125" - 0.186" - Pink
0.124" & Below - Red

Note: Readings at 0' through 9' are on conical section, 11' is on cylindrical section

ELEV.	N	NNW	NW	NWW	W	WSW	SW	SWS	S	SSE	SE	SEE	E	ENE	NE	NEE
16'																
15'																
14'																
13'																
12'																
11'	0.195	0.213	0.214	0.220	0.223	0.221	0.218	0.208	0.188	0.202	0.140	0.140	0.137	0.127	0.156	0.174
10'																
9'	0.192	**0.117**	0.192	0.203	0.207	0.170	0.189	0.170	0.150	0.159	0.151	**0.110**	0.127	0.167	0.203	0.168
8'	0.155	0.193	0.177	0.185	0.183	0.165	0.217	0.165	0.145	0.163	0.125	0.145	0.129	0.170	0.198	0.163
7'	0.158	0.225	0.186	0.167	0.172	0.201	0.228	0.200	0.163	0.148	0.151	0.189	**0.123**	0.145	0.188	0.201
6'	0.160	0.229	0.199	0.192	0.227	0.177	0.215	0.194	0.174	0.169	0.150	**0.124**	**0.117**	0.148	0.140	0.173
5'	0.153	0.211	0.180	0.191	0.231	0.183	0.201	0.210	0.156	0.164	**0.063**	**0.059**	**0.076**	0.153	0.212	0.159
4'	0.130	0.206	0.205	0.183	0.228	0.193	0.195	0.156	0.161	0.140	**0.050**	**0.068**	**0.089**	**0.080**	0.182	0.138
3'	0.127	0.208	0.178	0.191	0.216	0.189	0.192	0.135	0.163	0.148	0.129	**0.070**	0.185	**0.080**	0.192	**0.122**
2'	0.149	0.212	0.180	0.193	0.211	0.190	0.170	0.127	**0.118**	0.240	0.198	0.198	0.157	0.158	0.189	0.151
1'	0.148	0.166	0.166	0.185	0.181	0.208	0.173	0.148	0.155	0.237	0.248	0.199	0.180	0.248	0.189	0.193
0'	**0.093**	0.137	0.160	0.142	0.158	0.175	0.188	0.145	0.134	0.230	0.240	0.245	0.170	0.245	x	0.192

5 Star Testing, Inc.

Figure 4-1 2012 NDE Measurement of Wall Losses

Some valves in the CDS cooling water system have been reported as worn, which has contributed to some operating issues with the CDS cooling water system. No undue wear has been reported on the pumps aside from pump rebuilds.

Photo 4-7 Photos Showing Cooling Water Pump Suction Strainers Removed

All other equipment in this system was reported in working order with only normal maintenance activities.

Based on interviews and information provided, the following actions should be taken to assure the CDS equipment has a safe and reliable service until 2039.

With the history of corrosion issues in the CDS vessel discovered as early as 1998 and found again in 2012, it recommended that a CDS vessel wall thickness NDE mapping program be initiated with thickness testing performed at each major outage to monitor any erosion or corrosion within the CDS vessel. The results from the NDE should then be shared with the CDS vessel OEM or structural engineer to determine if additional steps are needed, or if a detailed structural review is required. Previous reports indicate the minimum required shell thickness for the CDS vessel is 0.144", but this should be confirmed in a structural review and not used as a governing guideline for CDS vessel structural integrity. Wallpapering of the CDS vessel has been considered several times and should be considered for installation if the NDE testing / structural review shows significant corrosion. The CDS vessel internal material buildups and removal processes further add to the importance of the NDE program. Not only do the CDS vessel internal buildups reduce scrubbing capacity and increase system pressure drop, they also increase the structural loading on the CDS vessel and support steel. A thinned CDS vessel wall loaded to internal buildup is more susceptible to structural failure.

Black Hills currently inspects each spray lance nozzle for wear and proper spray distribution on a twice-weekly schedule. This schedule appears consistent with the recommended OEM schedule. Black & Veatch agrees with this inspection schedule. This will help prevent material buildup in the scrubber that can be costly to remove while also increasing structural loading on the CDS vessel. Plugging of the spray lances was reported as the main contributor to internal CDS vessel material buildup in 2018 and can also lead to localized corrosion at the wetted areas of the CDS wall. A reinstated lance test station or new lance station at the spray elevation of the scrubber would allow this testing and inspection to take place.

Finally, it is recommended the scrubber cooling water be treated to kill biologicals, and suction strainers for the cooling water pumps should be installed. This will help to eliminate biological and other materials from damaging cooling water pump seals and plugging spray nozzles. Net positive suction head (NPSH) will have to be reviewed with the cooling pump OEM requirements if a suction strainer is added as to not reduce the NPSH available below the required NPSH of the pump. Periodic draining and cleaning of the cooling water tank at major outages will help reduce biological build ups as well.

The costs for NDE survey and structural review costs has been included in Appendix A.

A more detailed study of wallpapering or other means of internal corrosion protection is recommended once the NDE survey and structural review has been completed as these results will dictate the extent of wallpapering or other corrosion resistant materials.

Costs for the NDE survey and structural review, scrubber wallpapering, scrubber water treatment and suction strainer upgrades costs have not been included in Appendix A as they are not considered CAPX expenditures.

4.10.3.1 Reagent Receiving, Storage, and Preparation

The CDS reagent, receiving, storage, and preparation system consists of one (1) pebble lime silo, one (1) 100 percent capacity hydrator, two (2) hydrate transfer blowers, one (1) hydrated lime silo, and three (3) hydrate feeders.

The pebble lime that is trucked into the plant was reported as good quality and within specifications for the equipment in this system. Any out of specification pebble lime could cause undue wear to all equipment in this system. Both the pebble lime silo and the hydrated lime silo were reported as not being inspected, but no major issues with either silo was reported. Hydrator seasoning chamber vent line plugs continuously all the way back to the hydrator vent system fan (2BMA-FAN-1). The hydrator vent system fan pulls air from the CDS and vents back to the CDS. The hydrated lime metering feeders were reported as worn and needing replacement. The metering feeders in their worn condition do not provide true control of the amount of hydrated lime being feed to the CDS vessel for SO_2 scrubbing.

Based on interviews and information provided, current O&M practices are adequate, and the equipment should provide safe and reliable service until 2039. Replacement of the minor equipment indicated above should be considered for continued reliable operation.

A review of alternate hydrator seasoning chamber venting should be considered to resolve the current issues with the system. Modification costs of the hydrator seasoning chamber venting has not been included in Appendix A.

4.10.4 Fly Ash and Flue Gas Desulfurization Solids

The fly ash and CDS solids system consists of one (1) fly ash silo, combination filter/separator, ash conditioner/dry unloading spout, mechanical exhausters, fly ash vent filter, and conveying pipe and valves. The original United Conveyor Corporation (UCC) wet ash conditioner is still in use and is being considered for replacement along with the DCS control. All equipment in this system was observed in operation during unloading and appeared to be in working order.

The original UCC wet ash conditioner is being considered for an upgrade and is being evaluated in an engineering study. The benefits and costs of the replacement will be included in the engineering study.

Based on interviews and information provided, current O&M practices are adequate, and the equipment should provide safe and reliable service until 2039.

4.10.5 Bottom Ash System

The bottom ash system collects and removes bottom ash from the boiler. The equipment consists of bottom ash collection hoppers, bottom ash crushers, and a vacuum type pneumatic conveying system that transfers the bottom ash to the ash silo.

The current system has been in operation since 1995. Currently, the bottom ash system experiences frequent plugging with ash hanging up on the inside of the bottom ash hoppers. Operators currently must use manual methods to loosen and break up the ash by poking and raking operations. These operations expose personnel to internal boiler conditions during pressure excursions. Black Hills wants to completely eliminate all human interaction with the bottom ash system due to safety concerns. Additionally, the current system of bottom ash, fly ash, and Flue Gas Desulfurization (FGD) solids collect in a common storage silo creating unloading issues due to material stratification in the silo. The operation of unloading the silo into trucks through the ash conditioner causes dusting issues or over conditioned ash resulting in an unsatisfactory mixture.

In 2020 Black & Veatch performed a Bottom Ash System Study, (B&V Project NO. 403730) on NS2. The study compared several different options and recommended the UCC PAX bottom ash system option for replacement. In addition, the Bottom Ash Loadout System was recommended to be replaced. Details of the options and recommendations can be found in the full report on file with Black Hills.

Appendix A includes the estimated cost from the study for the recommended bottom ash and loadout system replacement scope of work. .

4.10.6 Best Available Technology (BAT) Considerations

Neil Simpson Unit 2 Air Quality Control (AQC) technology is early 1990 vintage. The original system was designed to meet permitted requirements; however, since its install, recently designed and installed AQCS systems are capable of achieving greater SO_2 reductions, including newer CDS systems. Therefore, NS2 is also considering alternative air quality control system (AQCS) technology in place of the existing CDS and ESP. The existing AQCS technology is still making emissions performance under the permitted limits as shown in Section 3.10.1. Black & Veatch performed an opacity improvement study in 2014, concluding the only guaranteed means of reducing opacity during startup would be to install some form of fabric filter. Options reviewed in the 2014 Black & Veatch study included a new polishing fabric filter, an ESP conversion to fabric filter, a partial ESP conversion to fabric filter, and a startup fabric filter. Further discussion of the benefits of each baghouse option can be found in the 2014 Black & Veatch report.

A fabric filter (FF) is a commonly used AQC technology for removing PM from a flue gas stream, and they work by forcing flue gas to pass through a bag that filters out the PM. The bags are vertically hung in steel compartments with each compartment typically containing dozens of bags and each fabric filter casing having a few to several compartments. FFs can be separated into two main types based on their cleaning method, a pulse jet fabric filter (PJFF) and a reverse gas fabric filter (RGFF). A PJFF sends a pulse of compressed air down the length of a bag to knock off the collected filter cake, and an RGFF sends a stream of low-pressure air through the bags to remove the filter cake. While RGFFs are still a viable technology, PJFFs have been installed more frequently compared to RGFFs in the last 20 years due to requiring less real estate and up-front capital costs.

PJFFs also provide an additional benefit when following an AQC system that targets acid gases, such as the CDS installed at NS2. The filter cake that collects on the bags will contain unreacted lime particles, and a PJFF forces the flue gas to pass through the filter cake, leading to additional reactions with acid gases. Residual chemical reactions occur within an ESP as well, but they do not occur at the same rate as in a PJFF due to the direct interaction with the flue gas and filter cake.

Suppliers of PJFF systems are normally willing to guarantee an emission of 0.010 lb/MMBtu, if not slightly lower.

The estimated cost of the fabric filter options is included in Appendix A. This cost does not include any demolition of existing equipment.

For the CDS, alternatives include a Spray Dryer Absorber (SDA). Currently with the existing CDS, pebble lime is converted to hydrated lime and used as reagent for SO_2 removal. An SDA uses pebble lime to create a lime slurry as the reagent for SO_2 removal. The lime slurry reagent would require additional new equipment to handle and prepare the lime slurry reagent, such as a slaker and storage tanks. Once the lime slurry is created, it is pumped from the storage tank and sprayed into an absorber vessel through a rotary atomizer or dual fluid nozzles. The slurry is injected at a high velocity and atomized into fine droplets to maximize the surface area for reactions with acid gases to occur.

New SDA systems are capable of achieving SO_2 removal percentages of low to mid 90 percent, which is on par with NS2's CDS system but slightly less efficient than current CDS systems that can achieve up to 98 percent removal, depending on the conditions of service.

The estimated cost for an SDA has been included in Appendix A. This cost generally does not account for cost savings from reusing certain CDS equipment, such as the pebble lime silos, but it is assumed the ESPs would remain operational (i.e. the cost in Appendix A does not include a new PJFF).

Another option for acid gas AQC systems is a wet flue gas desulfurization system (WFGD). A WFGD is located after a particulate control device and sends flue gas upwards through a vessel that cascades an alkali slurry countercurrent to the flue gas. While not universally true to all WFGD systems, limestone slurry is commonly used, and it is often sprayed into the absorber across multiple spray levels. For emission sources that burn a high-sulfur fuel and need to achieve a high SO_2 removal percentage, WFGDs are a practical way of achieving emission compliance.

However, WFGDs require a much larger footprint than NS2's CDS, and there is much more equipment associated with the WFGD (e.g. limestone handling equipment, ball mill slakers for creating slurry, classifiers for the slurry system, the WFGD vessel, a water treatment facility, and byproduct handling equipment), resulting in higher capital and annual O&M costs. For these reasons, WFGD systems are commonly installed at larger facilities than NS2, but it is still a technically feasible technology.

The estimated cost for a WFGD has been included in Appendix A. This cost assumes that the ESPs remain operational and that the ID fans are capable of providing sufficient draft.

Additional balance of plant equipment would have to be evaluated if either the baghouse, SDA, or both were installed. Equipment such as the ID fans would need evaluation for their capability to provide enough draft due to potentially increased pressure drop in the system. Other equipment such as compressed air, AQCS waste material processing equipment, and water availability for reagent preparation would also have to be evaluated. These costs have not been included in this report. It is suggested a more detailed study is performed on alternative AQCS technologies.

Black & Veatch understands that no specific removal technology is currently in use for Mercury removal. Black Hills is planning to upgrade the Mercury stack probes in 2021 (project no. 10070259).

Currently Neil Simpson 2 does not have means for reducing nitrogen oxides (NOx) from the flue gas. The best available technology is selective catalytic reduction (SCR), which is typically implemented on combustion units requiring a higher level of NOx reduction than achievable by selective non-catalytic reduction (SNCR) or combustion controls. Theoretically, SCR systems can be designed for NOx removal efficiencies close to 100 percent. Appendix A includes the estimated cost for a coal-fired SCR system including new ID fans. The cost does not include annual O&M costs and assumes that there are no major construction obstacles (e.g. adequate space is available). The cost for a coal-fired SCR are considerably higher than a gas fired boiler due to the amount of particulates in the coal-fired flue gas. If the SCR alternative is considered, a detailed engineering study will be needed.

4.11 CHIMNEY

The Chimney System consists of a dual wall steel stack supported on a concrete foundation. The chimney is 295 feet tall and is configured to develop a natural updraft to assist in the discharge of the combustion gas to the atmosphere (Photo 4-8). On the outside wall are miscellaneous platforms, ladders, and the breeching connecting to the ID fan. Insulation is installed between the dual walls.

Photo 4-8 NS2 Chimney

Platforms are provided at locations on the stack to access the emission monitoring test ports and the aviation obstruction lighting. The chimney is located west of the air quality control building. An access walkway from the air quality control building (BSB-0802) is provided for access to the platforms. A ladder with a safety climb device provides an alternate means of access to the platforms.

The Chimney was NDE inspected during the 2019 outage. No issues were found. A PM work order has been created for future inspections. Based on interviews and information provided, current O&M practices are adequate. The stack climbing system was upgraded in 2019. The chimney and grating structure are in good condition and should provide safe and reliable service until 2039.

The continuous emissions monitoring system (CEMS) to DCIS PLC was upgraded from GE model 9030 PLC to GE PAC System in 2016.

The new system will become obsolete in 15 to 20 years therefore replacement will be required after 2031.

Appendix A includes replacement of the GE PAC System after 2031.

4.12 INFRASTRUCTURE

4.12.1 Fire Protection System

During the 2019 Black & Veatch's walkdown the fire protection system was observed to be in good condition. The fire protection system is a dry type system therefore the piping should be in good condition but should be spot checked for pipe thickness and corrosion. Interviews with site staff noted the electronic fire detection and control system is outdated in that it is difficult to find service companies who can work on the system. Black Hills replaced the fire protection control system in

2020 (project no. 10061964). The new control system should provide reliable service and require minimal capital upgrades until 2039.

The major components provided in the fire protection water supply and storage system are one (1) diesel driven fire pump, one (1) electric motor driven fire pump, and one (1) electric motor driven jockey pump. The fire protection water supply and storage system interfaces with the site fire protection system.

The fire protection emergency diesel back up fire pump is 25 years old and was last overhauled 18 years ago. The pump is overdue for an overhaul or replacement.

Black & Veatch recommends the diesel fire pump and engine be replaced.

Appendix A includes the estimated cost for a diesel-powered fire pump.

4.12.2 Elevator

The NS2 turbine and boiler elevator is 25 years old. Elevators operated in a coal plant environment typically need replacement after 25 years of service. Elevator operation will become problematic and unreliable. This can be costly during unit outages due to lost productivity of work force. Additionally, the evacuation of an injured worker can be delayed by an out of service elevator.

Black Hills upgraded the unit elevator in 2020 (project no. 10061709). The new unit elevator should provide reliable service and require minimal capital upgrades until 2039.

4.12.3 Plant Communication System

The plant communication system is a GAI-Tronics public address (PA) system throughout the plant. The system is 25 years old and becoming obsolete. Repairs are becoming more frequent with availability of parts becoming less available. This system is the primary communication tool in the plant thereby being critical when safety issues in the plant need to be communicated plant wide.

Black Hills plans to replace the GAI-Tronics system in 2021.

4.12.4 Underground Piping

The boiler blowdown tank in located inside the pump room area adjacent to the east building wall. The blowdown tank drain is an approximate 8” pipe that runs under the pump room floor slab into a sump outside of the building. Recently, the drain pipe failed from corrosion and has been leaking under the slab. Black Hills abandoned the drain pipe and rerouted a new pipe line above ground to an inside trench where it remains enclosed in the pipe running to the outside sump (Photo 4-9).

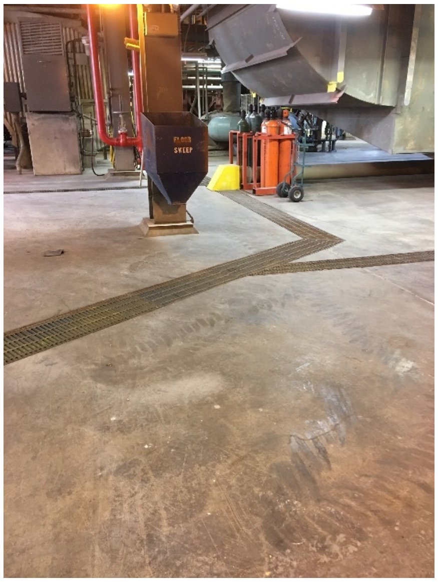

Photo 4-9 Blowdown Drain Pipe Routing to Sump

In 2020 Black Hills replaced the rerouted blow down pipe by installing a new underground pipe from the blowdown tank to the outside sump. The new drain line should operate safely until 2039.

Other underground wastewater piping systems which convey waste water to the CCR pond has been partially repaired or replaced because of leaks. When these underground pipes leak into the ground, it becomes an environmental and operational problem. These pipes should be replaced for continued operation of the plant.

The water treatment and storage capacity are enough for unit startup. Information provided and staff interviews did identify a bottle neck in the condensate supply pipe from the condensate storage tank to NS2 and Wygen 2 fill pump when there is a simultaneous unit startup. The pipe is an under sized pipe (2 ½”) running from the condensate storage tank to the plant and needs to be enlarged.

The estimated cost for replacing these underground pipes is included in Appendix A.

4.12.5 Facility Roofs and Drains

During the 2019 site walkdown, Black & Veatch observed the roofs were in good condition. NS2 boiler roof were replaced in 2015. Roofs should have a 30-year life; therefore, the NS2 boiler roof should provide satisfactory service with proper maintenance until 2039. Other facility roofs should be inspected and maintained as needed.

Black & Veatch recommends Black Hills initiate a roof inspection PM. PM inspection should be by a certified roofing contractor.

During staff interview the turbine roof fans (Photo 4-10) were noted to be in poor condition and difficult to maintain. Several fans are not working or in disrepair. The fan shroud and motor design only allow access to the motor and fan by scaffolding from inside the turbine room building. The result is hot conditions in the turbine room hall during the summer months.

Photo 4-10 Roof Fans

Black & Veatch recommended replacement of the roof fans in 2019. Black Hills has allocated funds in their five-year capital budget forecast for their replacement (project no. 10071566). Black & Veatch has not included allocated funds into Appendix A.

4.12.6 Building Heating

NS2 building heating is provided by a series of electric unit heaters with integral thermostat and controls. There are no provisions in the building heating design to supplement heating with steam. If steam heating were to be considered, an auxiliary boiler is required to supply steam during NS2 outages. Black Hills did not express interest in this option.

Staff interviews note the electric system is experiencing increased maintenance efforts to keep the system operating properly.

No additional information has been provided for the 2020 Life Assessment on the condition or deposition of the building heating system.

The estimated cost for upgrading the building heating system is included in Appendix A.

5.0 Recommendations

Based on findings of this life assessment, Black & Veatch recommends Black Hills continue funding NS2 O&M and capital fund for continued reliable and safe operation until 2039.

Black & Veatch has summarized the recommendations made throughout the report in Table 5-1.

Table 5-1 Summary of Recommendations

ITEM	RECOMMENDATION
BV1	Plan for replacement of the front convection pass (screen tubes) at the next major outage.
BV2	NDE testing and mapping of the furnace and convection pass roof.
BV3	Perform inspection and NDE testing of the SSH header including; tube stubs, drain stubs, vent stubs, nozzle block, support plates and outlet piping connection.
BV4	Inspect and monitor attemperator pipe body including attemperator components for refurbishment or replacement.
BV5	Continued inspection, thickness testing and maintenance of tube shields in the affected areas of the sootblower.
BV6	Perform periodic pipe thickness tests and ceramic liner inspection on the coal pipes to determine their condition and develop a replacement plan.
BV7	Perform periodic Coal Bunker inspection and testing in accordance to new testing plan.
BV8	Perform periodic visual and NDE testing of the FD, ID and PA fans
BV9	Evaluate HPU system to identify reliability issues and determine appropriate solutions
BV10	Investigating condensate water treatment capacity requirements for future cycling operation.
BV11	Replacement of the medium voltage (4160V) switchgear.
BV12	Replacement of the 480V SUS switchgear.
BV13	Perform detailed study of wallpapering the CDS vessel or other means of internal corrosion protection after the NDE survey and structural review has been completed - these results will dictate the extent of wallpapering or other corrosion resistant materials.

ITEM	RECOMMENDATION
BV14	Periodically Visually inspect chimney.

6.0 Conclusions

Based on information provided for the 2020 Life Assessment update, Black Hills Neil Simpson Unit 2 is in good condition. The Unit's age predicates increased vigilance of O&M, and processes and procedures must be maintained to continue reliable and safe operation of the Unit until 2039.

NS2 has been fortunate to have operated as a base load unit for the past 25 years of operation. With the uncertainty of future power market dispatch and relative cost of NS2 power generation, future dispatching of NS2 may require cycling. Cycling will affect all systems and equipment of the Unit. The highest impact systems will be the steam generation equipment, turbine, generator, ACC and switchgear.

Maintaining up to date maintenance service, inspection, testing, repair and replacement records will provide valuable information for the evaluation of cycling effects and the planning of repairs and replacement work to maintain safe and reliable operation of the unit until 2039.

Appendix A Neil Simpson Unit 2 – 2021 Estimated Capital Cost

Section	Location	Action Schedule	Impact Category	Item Description	Estimated Cost 2021 $USD
Boiler	Furnace	Next Major Outage	Reliability	Replace furnace rear wall arch tube panel and convection pass screen tubes.	$717,000
Boiler	Superheater	5+ Year Plan	Safety	Replace inlet and outlet sections of superheater	$1,274,000
Steam Generator	Waterwall Tubes	5+ Year Plan	Reliability	Chemical cleaning boiler steam generating section.	$187,000
Boiler Air and Gas	Heat Exchange Baskets	Reoccurring	Reliability	Air Heater Basket and Seals Replacement reoccurring every 8 years.	$1,051,000
Boiler Air and Gas	Steam Coil Air Heaters	5+ Year Plan	Reliability	Replace steam coil air heater and associated condensate level control equipment.	$162,000
Boiler Air and Gas	FD Fan Controllers	Next Major Outage	Safety	FD controller and damper upgrade	$438,000
BOP	Boiler Feed Pump	5+ Year Plan	Reliability	BFP Overhaul (two pumps).	$482,000
Chimney	CEMS	5+ Year Plan	Environmental	Replacement of the GE PAC System.	$58,000
Controls	DCS	5+ Year Plan	Reliability	ABB Network 90 Termination Units and I/O.	$531,000
Controls	PLC	5+ Year Plan	Reliability	Coal Pulverizer PLC.	$96,000

Section	Location	Action Schedule	Impact Category	Item Description	Estimated Cost 2021 $USD
Controls	PLC	5+ Year Plan	Reliability	Water Lance PLC.	$96,000
Controls	PLC	5+ Year Plan	Reliability	Waste Ash Silo Baghouse and Pug Mill Systems PLC.	$113,000
Controls	PLC	5+ Year Plan	Reliability	Powered Activated Carbon (PAC) Silos PLC.	$96,000
Controls	PLC	5+ Year Plan	Reliability	Amended Silicates Silo PLC.	$96,000
Controls	PLC	5+ Year Plan	Reliability	FPS Ignition System PLC.	$113,000
Electrical	Arc -Flash	< 24 months	Safety	Update Arc Flash study and Training.	$155,000
Electrical	Reserve Auxiliary Transformer (RAT)	5+ Year Plan	Reliability	Spare RAT.	$239,000
Electrical	4160V Switchgear 2APD-SWG-1	5+ Year Plan	Reliability	Replacement of Main 4160V Switchgear for Unit 2.	$2,771,000
Electrical	Batteries	Reoccurring	Reliability	Replace UPS battery charger/inverter at the end of 10 years.	$64,000
Electrical	480V SUS 2APC-SUS-11	5+ Year Plan	Reliability	480V SUS switchgear 2APC-SUS-11.	$132,000

Section	Location	Action Schedule	Impact Category	Item Description	Estimated Cost 2021 $USD
Electrical	480V SUS 2APC-SUS-12	5+ Year Plan	Reliability	480V SUS switchgear 2APC-SUS-12.	$139,000
Electrical	480V SUS 2APC-SUS-13	5+ Year Plan	Reliability	480V SUS switchgear 2APC-SUS-13.	$151,000
Environmental	Bottom Ash System	5+ Year Plan	Environmental	Black & Veatch recommended scope of work for replacement of the Bottom Ash Removal and Loadout Systems.	$5,602,000
Environmental	CDS	5+ Year Plan	Environmental	Replacing the CDS with an SDA.	$83,945,000
Environmental	ESP	5+ Year Plan	Environmental	ESP conversion to Fabric Filter.	$10,094,000
Environmental	CDS/ESP	5+ Year Plan	Environmental	Replacing the CDS with a WFGD.	$126,175,000*
Environmental	SCR	5+ Year Plan	Environmental	Installation of a SCR system.	$61,800,000
Environmental	ESP	5+ Year Plan	Reliability	Yearly ESP inspections.	$28,000
Environmental	ESP	5+ Year Plan	Reliability	UT survey of ESP internals and structural review.	$280,000
Environmental	Scrubber	5+ Year Plan	Reliability	UT survey of CDS Vessel internals and structural review.	$155,000

Section	Location	Action Schedule	Impact Category	Item Description	Estimated Cost 2021 $USD
High Energy Piping	Mainsteam Piping	5+ Year Plan	Safety	HEP on Mainsteam from Boiler Outlet to Turbine inlet analysis and NDT inspection and creep life study and hanger inspection.	$155,000
Infrastructure	Fire Protection	< 24 months	Safety	Diesel fire pump and engine be replacement.	$139,000
Infrastructure	Turbine Building	5+ Year Plan	Safety	PA system replacement.	$266,000
Infrastructure	Turbine Building	< 24 months	Infra Structure	Building Heating upgrade.	$361,000
Infrastructure	Turbine Building	5+ Year Plan	Infra Structure	Replace Boiler Building Roof Fans Ventilation.	$258,000
Infrastructure	Underground Piping	Next Major Outage	Infra Structure	Replace blow down tank drain line and condensate line.	$266,000
Steam Generator	Attemperator Body	Next Major Outage	Reliability	Attemperator pipe body including attemperator components be removed and refurbished or replaced.	$283,000
Steam Generator	Secondary Superheater	5+ Year Plan	Reliability	Secondary superheat section in boiler.	$1,223,000
Steam Generator	Economizer Tubes	5+ Year Plan	Reliability	Replace Economizer Section.	$2,899,000
Turbine	HP Upgrade	5+ Year Plan	Heat Rate	Replacement of the rotor, inner and outer HP cylinder and diaphragms.	$2,908,000

Section	Location	Action Schedule	Impact Category	Item Description	Estimated Cost 2021 $USD
Turbine	Blades	Next Major Outage	Reliability	Replacement of turbine HP moving and stationary blades.	$291,000
Turbine	Inspection	Next Major Outage	Reliability	Turbine Open clean close inspection.	$1,274,000
Turbine	Turbine	Next Major Outage	Heat Rate	Steam Path Audit.	$63,000

*Replacement of the CDS with WFGD would be an alternative option to the Combined Replace of the CDS with an SDA and ESP conversion to Fabric Filter.

DECOMMISSIONING AND DEMOLITION REPORT

This report assessed the feasibility and costs of decommissioning, demolishing, and remediating Neil Simpson Unit II and its site to grade in a condition that allows future industrial use.

The report identified:

- The necessary permits and authorizations.
- The needed environmental and cultural studies.
- Mechanical and electrical separations lists.
- The steps required for remediating the site.
- The costs of demolition: $9.94 million with a $1.29 million credit for scrap.

The report recommended a decommissioning and demolition plan to outline the deconstruction process and remediation of the site.

REV 2 –FINAL COMMENTS INCORPORATED

IRP STUDY DECOMMISSIONING AND DEMOLITION REPORT

Neil Simpson Power Plant – Unit 2

B&V PROJECT NO. 407186
B&V FILE NO. 40.2000

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PREPARED FOR

Black Hills Corporation

26 MARCH 2021

Table of Contents

1.0 Introduction

Black Hills Power (BHP) presently operates the Neil Simpson 2 coal-fired power facility (Project) near Gillette, WY. Black & Veatch was engaged by Black Hills Corporation to develop this feasibility study evaluating demolition and remediation of the existing Project, including demolition desktop cost estimate and permitting tables to support BHP's budgetary planning activities and development process.

2.0 Demolition

2.1 Demolition Approach

Black & Veatch's demolition approach included the following tasks:

- Review of data provided by BHP.
- Desktop review of demolition of the Project.
- No site visit was conducted.
- Consider issues and potential hazards associated with the demolition process.

The desktop estimate developed was based on information provided by BHP and Black & Veatch's proprietary estimating tool. Site specific and other technical data provided by BHP was utilized for this study. When site specific data was not available, typical data from Black & Veatch's in-house databases was used. Black & Veatch did not develop a decommissioning or demolition plan to help optimize the plant's final disposition or demolition strategy. A set of assumptions were developed based on previous experience.

There are no regulations which relate specifically to the dismantling of electric generating plants. However, as more power generating facilities are retired these requirements could evolve in future years.

Prior to moving forward with the decommissioning or demolition of the facility it is recommended that a complete Decommissioning and Demolition (D&D) plan, including a constructability analysis be prepared. A D&D plan is a valuable roadmap to the deconstruction, final functionality (as applicable), and appearance of the facility and is recommended as part of any future project. This document can further define the Project and enhance the accuracy of the cost estimate.

2.2 Demolition Scenarios

There is only one demolition scenario for the Project:

- Scenario 1 – Demolition of the entire coal plant to grade, leaving the site in a condition to allow use as an industrial facility.

2.3 Demolition Assumptions

For purposes of the demolition estimate, general demolition assumptions made for this cost estimate include the following:

- The Project does not contain hazardous materials in soils that may contain lead, PCBs, heavy metals or similar substances that would require environmental remediation.
- Environmental agencies tied to regulations which may apply to these scenarios were not contacted.
- Economic assumptions are based on regional cost estimates expressed in 2020 dollars and do not include escalation.
- The cost estimates are based on a turnkey contracting approach.

- No sale of any equipment on the new or grey market was considered. All equipment is considered for recycle/scrap value only. Considering costs associated with separating, storing, selling, and transporting equipment for potential salvage, Black & Veatch finds that there is no value in considering salvage.
- The Project transmission system beyond the plant substation was not removed and is not included as part of this analysis.
- The Project was constructed in 1995 therefore asbestos, PCB's and other hazardous materials are not included in the estimate. Lead paint abatement will be handled by the demo contractor as needed during demolition and is included in the demolition cost.
- Neil Simpson 2 and WYGEN2 separation (isolation) expenses are determined from a high level review of system P&ID drawings. Separation estimates include field labor, equipment and engineering for civil, structural, mechanical and electrical systems necessary for the continued operation of WYGEN2 prior to and after demolition of Neil Simpson 2. Appendix A and Appendix B shows generally the level of review of the Mechanical and Electrical systems respectively. Civil and Structural drawings were not available for review.
- The cost estimate is primarily based on a dismantling method utilizing either heavy equipment or explosives, or a combination of both, and removing all underground piping and sub-structures.
- Materials are assumed to be sorted on site, cut into 40 foot lengths and placed at a load out site on site for off-site transport. Demolition concrete will be chipped and separated from structural materials on site before disposal.
- Black & Veatch used average regional transportation cost for scrap and debris disposal for cost estimating purposes.
- A portion of concrete and asphalt materials around the Project area will be used as on-site backfill material. All voids will be filled to 6 inches below grade, then suitable fill will be placed to match existing grades and contours.
- It is understood that prior to the commencement of demolition activities the following Owner costs have been included in the estimate for the removal from the Project site by the Owner:
  - Project operating fuels (oil, gasoline, etc.).
  - Chemicals.
  - Fluids in tanks, pipes, barrels, storage areas, and other container and media.
  - Spare parts, tools, etc.; including those in the Warehouse.
  - All mobile equipment and vehicles (i.e., graders, dozers, haul trucks, passenger vehicles, etc.).
- Additional funds of $100,000 were allocated in the estimate for engineering, design, additional investigations and studies, light construction activities, and other activities supporting the demolition scenario.
- The estimate includes an allowance of 2 percent of the direct costs to cover the following:
  - Project site monitoring, security, environmental monitoring, and other Project operating and maintenance (O&M) expense during the demolition period.

- Project insurance costs, property taxes, and other similar economic obligations.

2.4 Demolition Cost Estimate

The costs provided below are based on assumptions and observations defined in this study and information provided by BHP and supplemented with Black & Veatch estimate data. Salvage value estimates are based on typical salable materials and estimate quantities.

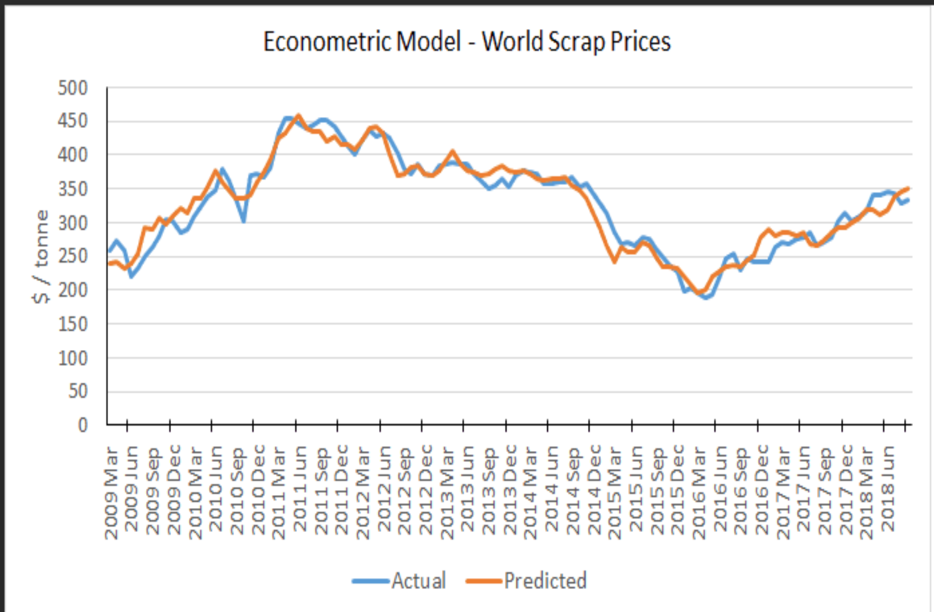
DESCRIPTION SCENARIO 1	2021 $USD
Separation Expenses	$387,000
Decommissioning Labor	$618,000
Decommissioning Equipment	$464,000
Decommissioning Engineering	$78,000
Demolition Labor	$1,288,000
Demolition Equipment	$1,803,000
Construction Indirects	$773,000
Engineering and Construction Management	$129,000
Site Preparation & Permits	$876,000
Hazardous Materials Abatement	$515,000
Trucking	$1,417,000
Engineering Support	$129,000
Contingency	$1,030,000
Overhead & Fee	$437,000
Scrap Value - Credit	($1,288,000)
Owners Cost - with Scrap Value	$8,651,000
Owners Cost - excluding Scrap Value	$9,939,000

This is a Class 5 budget estimate per the Association for the Advancement of Cost Engineering (AACE) guidelines in 2021 dollars or approximately: low -20 percent to 50 percent and high +30 percent to +100percent.

Black & Veatch used www.globalscrap.com as the basis for estimating scrap costs. There are several factors that affect the prices of scrap metal commodities throughout the US and internationally. All of the following factors affect one another and do not operate independently when determining scrap prices:

- Market Price.
- Industry Demand.
- Location.
- Time of Year.

The following chart shows the percent variation in metal and scrap metal indexes between 2009 – 2020, which is indicative of the impact to scrap price based on index variation.



Source: Steelonthenet.com. All prices are average world export fob prices in $ / metric tonne.

2.5 Demolition Special Considerations

Several special considerations could alter these estimated demolition costs which can include but are not limited to the following: on-site investigations, identification of actual equipment and material weights, constructability challenges, changes in environmental legislation, the extent of environmental impacts from plant operations (e.g., surface soil, pond sediment), changes in economic considerations such as labor rates, demolition costs, or scrap values, changes in material disposal regulations/methods, changes in contracting methodology, allocations for engineering and construction management, changes to Project contingency costs, changes to the location where demolition materials are disposed, changes in assumed Project closure requirements, or a change in the future use of the site.

3.0 Remediation

Following decommissioning of the Facility, remediation of the property may be required to cleanup any contamination to support new use. Because the plant was constructed in the 1990s, many of the legacy environmental problems typically associated with decommissioning-asbestos, PCBs, lead paint-are not applicable. However, other hazardous substances may be present on the property requiring assessment and remediation. For example, surface soil should be tested for mercury and other airborne contaminants and addressed if above regulatory levels. The intended reuse of the property will drive the level of any remediation of the Facility. It is recommended that cleanup is necessary to allow reuse.

Following decommissioning and demolition of the Facility, it is recommended that baseline soil and groundwater sampling be completed to assess whether the site should be enrolled in a cleanup, and what level, if any, of environmental remediation is required to meet applicable remediation goals for the intended reuse of the property. Because the property will likely be developed for another industrial use, if cleanup of soil and material is necessary, remediation to background levels or residential standards will not be required. Rather, institutional or engineering controls can be established to manage site use and allow less restrictive cleanup standards to be applied to impacted media.

4.0 Permitting

4.1 Permit Summary and Regulations for Site Demolition/Remediation

Black & Veatch has evaluated the required environmental permits and authorizations needed for the proposed demolition/remediation at the Facility. The required environmental permits and authorizations are identified below.

- Electrical cut and cap permit.
- Water cut and cap permit.
- Sanitary sewer cut and cap permit.
- Gas cut and cap permit.
- Telephone cut and cap.
- Cable cut and cap.

In addition to the permits and authorizations that have been identified, certain environmental and cultural studies will also need to occur prior to obtaining permits required for the proposed demolition/remediation phase. Black & Veatch has determined that a Threatened and Endangered Species Site Assessment, and a Cultural Resources study will need to be conducted prior to permit application submittal. It is estimated that each of these studies will take approximately 2-3 months to complete.

Appendix A. Mechanical Separation List

Drawing Number		Drawing Title	Cross Tie	Separation Point
2UUU	M2000	Index	No	
2UUU	M2001	Legend	No	
2ASA	M2021	Bottom Ash	TBD	Service Water Control Air
2ASB	M2022	Fly Ash	Yes	Control Air WYGEN Ash Silo tie in Valve 70
2ASC	M2023	Boiler Hoper Ash	TBD	
2ASD	M2024	Pulverizer Rejects	TBD	
2PSA	M2061	Auxiliary Steam Supply	TBD	
2BMA	M2101	Scrubber Additive	Yes	Room Air to WYGEN Day Silo
2CCB	M2142	Particulate Removal	No	
2CCC	M2143a	Desulfurization	No	
2CCC	M2143b	Brine Feed	TBD	Service Water (663-17)
2CCE	M2145	Induced Draft	No	
2CAA	M2181	Station Air	Yes	To WYGEN - Valve 233
2CAB	M2182	Control Air	Yes	To WYGEN - Valve 132
2CFA	M2221	Construction Facilities	TBD	
2HRA	M2261	Condensing	No	
2HRB	M2262	Condenser Air Extraction	TBD	Auxiliary Steam 061-1
2DPA	M2281	Building Drains and Plumbing	TBD	Turbine Roof Drains
2ECA	M2321a	Auxiliary Cooling Water	Yes	To WYGEN Valve 231 Valve 233
2ECA	M2321B	Auxiliary Cooling Water	TBD	Service Water (663-2)
2FWA	M2341	Boiler Feed	No	
2FWC	M2343	Condensate	TBD	No Information on Condensate Storage Requires detailed evaluation
2FWE	M2345	Cycle Chemical Feed	No	
2FWF	M2346	Cycle Makeup and Storage	Yes	Cycle Makeup Water To WYGEN Valve 33

Drawing Number		Drawing Title	Cross Tie	Separation Point
2FPA	M2361	Building Fire Protection	Yes	Required detailed evaluation
CFOA	M2401	Fuel Oil Supply	TBD	Required detailed evaluation
2FOB	M2402	Fuel Oil Receiving and Storage	TBD	Fuel Oil Storage Supply (401-01) Recirculation to FO Tank (01-401)
2PMA	M2481	Chemical Cleaning	No	
2PMB	M2482	Shutdown Corrosion Protection	TBD	Connection to Nitrogen Vessel Connection
2SAC	M2523	Steam Cycle Sampling and Analysis	No	
CSTG	M2547	Site Fire Protection	TBD	Required detailed evaluation
2SGA	M2581a	Steam Generator Sheet A	TBD	Aux Steam (2-061)
2SGA	M2581B	Steam Generator Sheet B	TBD	Aux Steam (061-02) Service Water Header (663-9)
2SGB	M2582	Combustion Air	No	
2SGC	M2583	Air Preheat	TBD	Auxiliary Steam (061-3)
2SGE	M2585	Ignitor Fuel	TBD	Control Air (182-8) Fuel Oil Supply (402-2)
2SGF	M2586	Boiler Vent and Drains	No	
2SGG	M2587	Main Steam	No	
2SGI	M2589	Soot Blowing	TBD	Station Air (181-8) WYGEN Soot Blower Drains Valve 125 Service Water Header (663-8)
2SGK	M2591	Temporary Blowout	No	
2TEA	M2601	High Pressure Extraction	No	
2TEB	M2602	Low Pressure Extraction	No	
2TEC	M2603	Extraction Traps and Drains	No	
2TED	M2604	Heater Drains	No	
2TEF	M2606	Heater Vents and Misc. Drains	TBD	Nitrogen Supply (482-3)
2TGC	M2623	Turbine Seals and Drains	TBD	Auxiliary Steam (061-4)
2TGD	M2624	Turbine Lube Oil	No	

Drawing Number		Drawing Title	Cross Tie	Separation Point
2WWA	M2641	Chemical Waste Drainage and Treatment	TBD	Required detailed evaluation
2WWB	M2642	Sanitary Drainage and Treatment	TBD	Required detailed evaluation
2WWC	M2643	Wastewater Collection and Treatment	Yes	To WYGEN2 Valve 30 Requires detailed evaluation
CWSA	M2661	Well Water	Yes	To Service Water/Fire Water Storage Tanks (1-66
2WSC	M2663	Service Water	Yes	Required detailed evaluation
CWSE	M2665	Fire Protection Water Supply and Storage	Yes	Required detailed evaluation
2WSG	M2667	Scrubber Makeup Water	Yes	Existing Unit 1? Ash Sluice Pipe
2WTD	M2684a	Cycle Makeup Treatment	TBD	Service Water (663-1) Control Air (182-3)
2WTD	M2684b	Cycle Makeup Treatment	TBD	Required detailed evaluation
2WTD	M2684c	Cycle Makeup Treatment	No	

Appendix B. Electrical Separation List

Drawing Number		Title	Cross Tie	Separation Point
2UUU	E0001	Index		
2APD	E1001	Overall one-line Diagram	TBD	Requires physical equipment location evaluation
2APD	E1011	One-Line 4160V Switchgear 1	TBD	Requires physical equipment location evaluation
2APD	E1012	One-Line 4160V Switchgear 1	Yes	Air Compressors Requires physical equipment location evaluation
2APD	E1051	One-Line Metering & Relaying Steam Turbine	Yes	To 69KV Substation CT's on NSS#1 69KV T Line Side of 69KV Breaker 6351 DWG CPP. E8001 87GT1 - "A" To 69KV Substation CT's on WYODAK 69K' Line Side of 69KV Breaker 6354 DWG CPP. E8001 87GT1 -"B" Trip Mat Main BRKR, RAT Main BRKR 635: 6354 - 86G1
2APC	E1101	One-Line 480V SUS 11 & SUS 12	TBD	Requires physical equipment location evaluation
2APC	E1102	One-Line 480V SUS 13 & SUS 14	TBD	Requires physical equipment location evaluation
2APC	E1103	One-Line 480V SUS 15 & SUS 16	TBD	Requires physical equipment location evaluation
2APC	E1201	One-Line 480 Motor Control Center 111	TBD	Requires physical equipment location evaluation
2APC	E1202	One-Line 480 Motor Control Center 112	TBD	Requires physical equipment location evaluation
2APC	E1203	One-Line 480 Motor Control Center 121	TBD	Requires physical equipment location evaluation
2APC	E1204	One-Line 480 Motor Control Center 131	TBD	Requires physical equipment location evaluation
2APC	E1205	One-Line 480 Motor Control Center 141 & 143	TBD	Requires physical equipment location evaluation
2APC	E1206	One-Line 480 Motor Control Center 151	TBD	Requires physical equipment location evaluation
2APC	E1207	One-Line 480 Motor Control Center 161	TBD	Requires physical equipment location evaluation
2APC	E1208	One-Line 480 Motor Control Center 161	TBD	Requires physical equipment location evaluation

Drawing Number		Title	Cross Tie	Separation Point
2CMA	E1301	One-Line Plant Communication Diagram - Intercommunications	TBD	Requires physical equipment location evaluation
2CMD	E1303	One-Line Plant Communication Diagram - Telephone	TBD	Requires physical equipment location evaluation
2APH	E1305	One-Line Station DC Power Supply	TBD	Requires physical equipment location evaluation
2APH	E1305A	One-Line Station DC Power Supply	TBD	Requires physical equipment location evaluation
2API	E1315	One-Line Essential Services AC Reliable Power Supply	TBD	Requires physical equipment location evaluation
2APD	E1401	Three-Line Diagram System - Phasing	Yes	To 69KV Substation
2APD	E1411	Three-Line Diagram System - Metering and Relaying Generator, Main Aux XFMR and GSU XRMR	TBD	Requires physical equipment location evaluation
2TGB	E1420	Three-Line Diagram System - Synchronizing	Yes	Substation Breakers
2APD	E1421	Three-Line Diagram System - Metering and Relaying 4160V feeder breakers_HV MCCs	TBD	Requires physical equipment location evaluation
2APD	E1422	Three-Line Diagram System - Metering and Relaying 4160V Plant SWGR 1	TBD	Requires physical equipment location evaluation
2APC	E1601	One-Line Administration Buiding Power Panel	Yes	Requires physical equipment location evaluation
2APC	E1611	One-Line 277/480 V Lighting Power Panel	TBD	Requires physical equipment location evaluation
2APC	E1621	One-Line Turbine Heater Power Panel 111, 112, 121 and 122	TBD	Requires physical equipment location evaluation
2APC	E1622	One-Line Turbine Heater Power Panel 151, 152, 161 and 162	TBD	Requires physical equipment location evaluation
2APC	E1641	One-Line 480V Power Panels	TBD	Requires physical equipment location evaluation
2APB	E1651	One-Line 120/208V Panelboards 1111 & 1112	TBD	Requires physical equipment location evaluation
2APB	E1652	One-Line 120/208V Panelboards 1113 & 1121	TBD	Requires physical equipment location evaluation
2APB	E1653	One-Line 120/208V Panelboards 1211 & 1212	TBD	Requires physical equipment location evaluation
2APB	E1654	One-Line 120/208V Panelboards 1213 & 1311	TBD	Requires physical equipment location evaluation

Drawing Number		Title	Cross Tie	Separation Point
2APB	E1655	One-Line 120/208V Panelboards 1511 & 1611	TBD	Requires physical equipment location evaluation
2APB	E1656	One-Line 120/208V Panelboards 1 & 2	TBD	Requires physical equipment location evaluation
2EEA	E1701	One-Line Freeze Protection Panels	TBD	Requires physical equipment location evaluation
2API	E1901	Panelboard Diagrams - 120V AC Station UPS Power Panel 1A, Section 1	TBD	Requires physical equipment location evaluation
2API	E1901a	Panelboard Diagrams - 120V AC Station UPS Power Panel 1A, Section 2	TBD	Requires physical equipment location evaluation
2API	E1905	Panelboard Diagrams - 120V AC Station UPS Power Panel 1B, Section 1	TBD	Requires physical equipment location evaluation
2API	E1905a	Panelboard Diagrams - 120V AC Station UPS Power Panel 1B, Section 2	TBD	Requires physical equipment location evaluation
2API	E1910	Panelboard Diagrams - 120V AC Reliability Power Panel 2	TBD	Requires physical equipment location evaluation

F. VARIABLE ENERGY RESOURCE INTEGRATION REPORT

This integration report assessed the incremental regulation costs to integrate more renewable resources—wind, solar, and BESS—into Black Hills Power's generation mix at several key sites. The report estimated the incremental regulation costs required to maintain reliability and frequency regulation, and assessed flexible capacity requirements. In addition, the report determined the accreditable capacity of variable energy resources (VER) for reliability planning.

Regulation costs through WAPA's OATT are: $1.04/MWh for wind at a 40% capacity factor; $1.12/MWh for solar at a 25% capacity factor.

The effective load carrying capacity (ELCC) ranges from 29% and declines to 4% as resource amounts increase. Wind is higher than solar mainly because of the higher capacity factor. For BESS, ELCC values range from 80% for a 20 MW installation to 49% for a 100 MW installation.

HITACHI ABB

REPORT

Black Hills Power Variable Energy Resource Integration Report

CCS-DA-20-00007680.00

PREPARED FOR

Black Hills Corporation

PREPARED BY

Hitachi ABB Power Grids Advisory Services

March 12, 2021

NOTICE

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1 Introduction

The Hitachi ABB Power Grids Energy Market Advisors team is part of the Energy Market Intelligence solution area that provides tools and analysis around market and transmission modelling, analysis, and price forecasting to support investment decisions, regulatory compliance, trading, energy operations, and renewable integration.

1.1 Scope of Study

Black Hills Corporation retained the Hitachi ABB Power Grids Energy Market Advisors team (PG) to complete an assessment of the incremental regulation costs of Black Hills Power (BHP) to integrate future levels of renewable resources onto its power system. In completing this assessment, PG examined forecast and actual load, wind generation and solar generation data to develop estimates of incremental regulation capacity that BHP will require to maintain reliability and frequency regulation. PG also completed production cost simulations using the Portfolio Optimization software to develop cost estimates of carrying the incremental regulation capacity amounts, and an additional assessment of flexible capacity requirements was also completed. These analyses were completed for a combination of wind, solar and battery energy storage resource expansions at several key sites on the BHP system. PG also completed an assessment to determine the accreditable capacity of Variable Energy Resources (VER) for reliability planning purposes.

1.2 Study Summary – Regulating Reserves

The assessment examined renewable and energy storage resource additions at several different locations to assess incremental impacts on BHP regulation requirements and costs. The assessment evaluated twelve different renewable and energy storage resource expansion options and five different potential geographic locations for those resources. These resource options and locations were specified by the BHP planning team, based on commercial interest it has seen in developing resources at those locations, and with a goal of capturing impacts of geographic diversity in wind and solar generation profiles within its service territories.

The basic approach taken to assess regulating reserve requirements for the BHP system was to evaluate compliance with the North American Reliability Council (NERC) Control Performance Standard 2 (CPS2) reliability requirements. While those requirements do not strictly apply to BHP, they were used in this assessment as a proxy for operational challenges that will arise from increased wind and solar integration and impacts of those challenges on BHP operations and resource expansion decisions. Under the CPS2 reliability requirements, BHP system Area Control Error (ACE) is monitored on a 10-minute interval, and any violations of frequency deviations are tabulated. Events where ACE deviates outside of high and low bands are tagged as a frequency violation and needed regulation capacity is calculated as incremental Regulation Up or Regulation Down capacity needed to ensure that the BHP ACE stays within upper and lower bands 98 percent of the time.

To determine the system cost of the additional Regulation Up and Regulation Down PG completed production cost simulations, modelling both the resource inclusion and associated incremental Regulation Up and Regulation Down capacity requirements. The difference in total system production costs between each portfolio's simulation with and without the incremental

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regulation capacity was used to develop estimated cost per MWh for carrying the incremental Regulation Up and Down capacity.

Table 1 provides a summary of the renewable and energy storage resource options and projected regulation requirements resulting from the assessment. As shown, resource portfolios include wind additions of 50, 100 and 200 MW at Cheyenne, South Gillette and North Douglas, WY locations, and solar additions of 50, 100 and 200 MW at Cheyenne WY, Gillette WY and Hot Springs SD locations. The resource portfolios also include pairing of 100 MW solar with 40, 20 and 60 MW battery energy storage capacity at the Cheyenne, Gillette and Hot Springs locations, as well as stand-alone 20, 40 and 60 MW battery energy storage projects at those same three respective locations.

Table 1. Summary of Incremental Regulation Requirements and Costs

Portfolio	Type	Size (MW)	Location	98% CPS2: Incremental Regulation Up (MW)	98% CPS2: Incremental Regulation Down (MW)	Regulation Cost – BHP Generation ($/MWh)	Regulation Cost – WAPA Tariff ($/kW/Mo)
Existing System				55	50		
1	Wind	50	Cheyenne	24	0	$10.17	$0.303
2	Wind	100	S. Gillette	26	22	$6.56	$0.303
3	Wind	200	N. Douglas	50	40	$11.12	$0.303
4	Solar	50	Cheyenne	7	1	$5.38	$0.205
5	Solar	100	Gillette	10	1	$4.63	$0.205
6	Solar	200	Hot Springs	11	1	$1.57	$0.205
7	Solar + Storage	100 + 40	Cheyenne	0	1	$0.02	$0.205
8	Solar + Storage	100 + 20	Gillette	0	1	$0.03	$0.205
9	Solar + Storage	100 + 60	Hot Springs	0	1	$0.02	$0.205
10	Storage	20	Cheyenne	0	1	N/A	
11	Storage	40	Gillette	0	1	N/A	
12	Storage	60	Hot Springs	0	1	N/A	

As shown in Table 1, Regulation Up requirements for the BHP existing power system are 55 MW, and Regulation Down requirements are 50 MW. Incremental Regulation Up requirements range from zero to 50 MW, and incremental Regulation Down requirements range from 1 to 40 MW. Regulation costs projected from use of BHP's generation range from $1.57/MWh for a 200 MW solar addition at Hot Springs, SD, to $11.12/MWh for a 200 MW wind addition at North Douglas, WY. BHP also has an option to procure regulation from WAPA, through its Open Access Transmission Tariff (OATT) at a lower cost. WAPA's current tariff offers regulation service for a fixed cost of $0.303/kW/Month for wind resources, and $0.205/kW/Month for solar resources. At a 40% annual average wind capacity factor, the WAPA regulation cost is equivalent to $1.04/MWh for wind resources, and at a 25% annual average capacity factor for solar, it would be equivalent to $1.12/MWh for solar resources. For solar resource options that include battery storage, the battery capacity is sufficient to offset incremental Regulation Up capacity requirements associated with operation of the solar resources, so that on net, additional

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regulation capacity is not required. In those cases, the incremental regulation cost listed is associated with provision or procurement of Regulation Down.

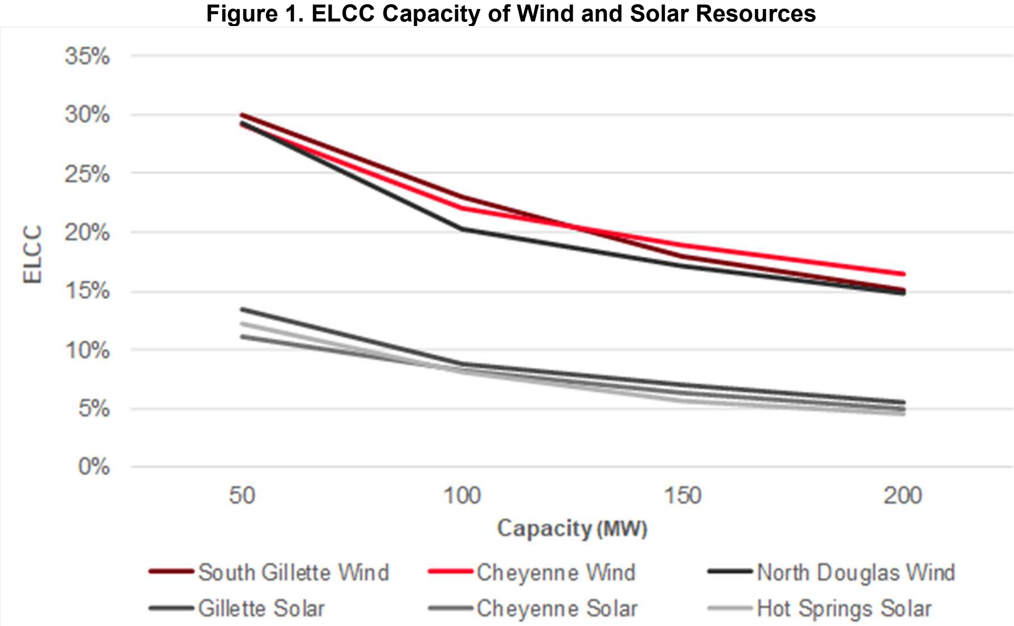
1.3 Study Summary – Flexible Capacity Requirement

In addition to assessing incremental regulation requirements and costs likely to be incurred due to changes in BHP operating costs, PG also completed an assessment of whether BHP is likely to require additional flexible capacity to integrate the Resource Portfolios. PG used a methodology originally developed by the California Independent System Operator (CAISO) to assess BHP's flexible capacity requirements. This assessment showed that BHP's existing flexible capacity is sufficient if the variable energy resources identified in the portfolios studied are added to their system with exception to three cases: 1.) Portfolio 3, which creates a Flexible Capacity need of 86 MW, 2.) Portfolio 5 which creates a 16 MW Flexible Capacity need, and 3.) Portfolio 6, which creates a 118 MW Flexible Capacity need. The cost of flexible capacity is typically tied to the carrying cost of flexible peaking capacity. Black & Veatch is currently completing a study of busbar costs for new generation on the BHP system, and those costs and the flexible capacity requirements identified above will be reflected in BHP's Integrated Resource Plan development for Resource Portfolios 3, 5 and 6.

1.4 Study Summary – Effective Load Carrying Capability

PG also completed an Effective Load Carrying Capability (ELCC) assessment of the wind, solar and battery storage resource portfolio options, to assess the level of reserve capacity that each option provides to BHP, for use in its resource planning studies and resource procurement activities. The ELCC analysis is used to determine the percentage of the nameplate capacity of each resource type and location that can be counted on for reserve margin planning purposes.

Figure 1. ELCC Capacity of Wind and Solar Resources



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As shown in Figure 1, the ELCC values for wind are comparable at all three locations for 50 MW resource additions. For 100 MW wind resource additions, ELCC values are highest at South Gillette, followed by Cheyenne and then North Douglas. Projected ELCC values at South Gillette begin at 30 percent with a 50 MW wind addition and decline with additional wind expansion. The ELCC values for wind at Cheyenne and Douglas begin in the 28 percent range and also decline with additional wind expansion. However, for the Cheyenne site, estimated ELCC values see a lesser decline than the other two sites, for wind additions of 150 and 200 MW.

For solar resources, ELCC values are highest at the Gillette location, followed by Hot Springs and then Cheyenne. Solar ELCC values are considerably lower than those for wind resources, ranging in the 11 to 13 percent range with 50 MW additions, and declining to around 5 percent with 200 MW solar additions. The primary driver for lower solar ELCC values is a lower capacity factor for solar resources, compared to wind.

PG also calculated the ELCC value of stand-alone battery storage at four capacity levels, 20 MW, 40 MW, 60 MW and 100 MW. We determined the battery charge level in every hour to calculate the amount of capacity that a stand-alone battery storage facility can provide. This capacity ranges between 0 MW and the maximum capacity of the storage facility. Table 2 lists the estimated ELCC values. As the size of the capacity increases from 20 MW to 60 MW, the effective capacity contribution is expected to decrease from 80% to 54%.

Table 2. ELCC of Battery Storage

Type	Capacity (MW)	Incremental Demand (MW)	ELCC (%)
Storage	20	16	80%
Storage	40	27	67%
Storage	60	33	54%
Storage	100	49	49%

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2 Variable Energy Resource Projections

2.1 Introduction

Black Hills Corporation retained Hitachi ABB Power Grids (PG) to complete a VER Integration Study for Black Hills Power (BHP). BHP has been adding renewable resources to its system in recent years, given improvements in the economic and generation performance of wind and solar technologies. To support its Integrated Resource Planning, and in anticipation of adding greater amounts of wind and solar variable energy resources to its power system, BHP recognized the need to complete a study of operational and reliability requirements it is likely to face in response to greater levels of variable energy resources on its system.

2.2 Study Approach

It is important to understand the impact that higher levels of wind and solar penetration will have on BHP operations, and to identify operational and resource planning steps that can be taken to assure that grid stability is not compromised. BHP has successfully integrated several wind projects onto its current system, but with additional wind and solar resources expected to come on-line in coming years, additional steps may be required to manage increased variability in generation and net load levels. PG completed this study of variable energy resource integration requirements by implementing a series of integrated analytic steps, and results from this analysis will be further implemented into BHP's current Integrated Resource Planning process and study results.

In completing this assessment, PG examined forecast and actual load, and thermal, wind and solar generation data to develop estimates of incremental regulation capacity that BHP will require to maintain reliability and frequency regulation. A key goal of the analysis was to quantify the variability in wind and solar generation facilities and to estimate the quantity and value of 10-minute operating reserves necessary to maintain reliable system operation. The assessment examined the impact of wind and solar resource additions separately to estimate incremental regulating reserve capacity required with each resource type and location. PG also completed production cost simulations using the Portfolio Optimization software to develop cost estimates of carrying the incremental regulation capacity amounts. These analyses were completed for a combination of wind, solar and battery energy storage resource expansions at several key sites on the BHP system. PG also completed an assessment to determine the accreditable capacity of VERs for reliability planning purposes.

The basis analytic steps implemented by PG in completing this study include the following:

1. **Data Development** – PG worked with the BHP team to gather available system load data at the hourly and sub-hourly level, and to develop generation profiles for the renewable resource portfolio options, again at an hourly and sub-hourly level. The BHP team also provided historical and forecast generation data at an hourly and sub-hourly level. For areas where data gaps existed, particularly for sub-hourly level data, the PG team supplemented available data by utilizing publicly available data from the National Renewable Energy Lab (NREL).

2. **Estimate Incremental Regulation Capacity Requirements** – To estimate incremental regulation capacity, PG utilized available BHP and NREL data to develop a consolidated set of actual and forecast load, thermal generation, and renewable generation on a 10-minute interval basis. The historical data were adjusted to reflect planned resource additions and load growth on the BHP system for the year 2025. The actual and forecast load and generation data were used to estimate ACE for the BHP system, both with and without each of the Portfolio renewable resource and battery energy storage resource additions. ACE values on a 10-minute basis were compared to base level regulation requirements, where base level requirements were developed using NERC's recommended L_{10} formula. ACE values were then re-calculated independently for each of the 12 renewable resource portfolios, and CPS2 violations were tagged. Incremental Regulation Up and Regulation Down capacity levels were identified as the minimum amount of regulation capacity needed to ensure there are no CPS2 violations at least 98 percent of the time.

3. **Estimate Cost Impact of Carrying Incremental Regulation Reserves** – For each of the renewable resource portfolio options, PG completed Portfolio Optimization simulations, modeling both the resource inclusion and associated incremental Regulation Up and Regulation Down capacity requirements. The difference in total system production costs between each portfolio's simulation with and without the incremental regulation capacity was used to estimate the cost, per MWh, for carrying the incremental Regulation Up and Down capacity. The values calculated are per net energy production for each respective renewable project in the portfolio. PG also examined maximum 3-hour ramping requirements associated with the wind and solar additions and used those data to estimate the current and incremental need for flexible capacity on the BHP system, associated with each of the renewable resource portfolios. This assessment also included an evaluation of BHP's current flexible capacity resources, to determine if any of the renewable resource portfolios is likely to require procurement of incremental flexible capacity.

4. **Estimate Effective Load Carrying Capability** – For each of the renewable resource portfolio options, PG developed estimates of the Effective Load Carrying Capability (ELCC) of the resource, based on analysis of changes in loss-of-load probability associated with including that resource in BHP's supply portfolio, compared to inclusion of a "perfect" capacity resource as a substitute.

2.3 Variable Energy Resource Integration Considerations

Renewable generation resources, such as wind and solar, are variable and uncertain in nature because generation output depends on ever-changing wind speeds and solar irradiance that cannot always be accurately predicted. To manage the uncertainty associated with these types of resources, system operators can hold additional reserves so the power system can economically respond to unexpected events and generation fluctuations. High penetration levels of wind and solar resources leads to an increase in reserves necessary to reliably operate the power system. The fundamental need when integrating variable energy resources on a system is to have sufficiently flexible capacity or load to allow for adjustments for unpredicted increases or decreases in variable energy generation levels, without creating reliability problems or

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unacceptable levels of imbalance energy. There are a number of factors that improve the ability to integrate variable energy resources:

- Geographic diversity in siting variable energy resources reduces overall variability in generation for those resources, due to weather diversity and reduced adverse impacts on wind and solar generation from localized weather events

- Improved load and variable energy resource generation forecasting reduces unplanned swings in generation and net load, and reduces the overall integration requirement and cost

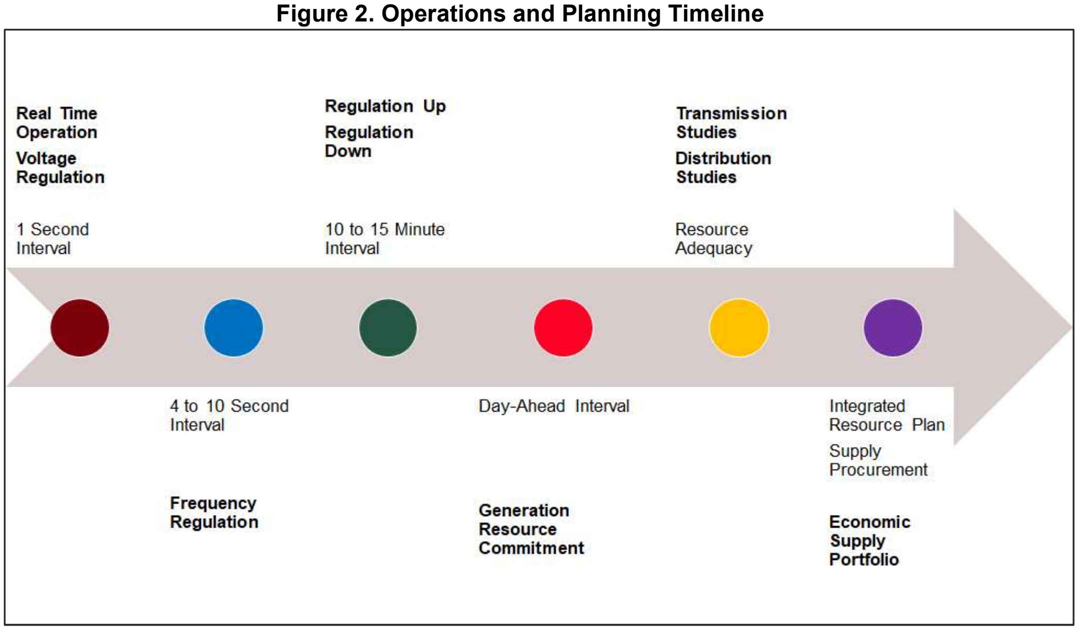
- Scheduling generation resources on a sub-hourly basis also reduces overall resource variability and deviation from forecast, and reduces overall regulation requirements in operating a power system

- Availability of flexible generation and/or energy storage on the power system to rapidly increase or decrease generation to offset unplanned decreases or increases in variable energy resource output.

2.4 System Operations and Planning Timeline

Reliable operation of a power system requires different actions and resource adjustments within different timeframes, ranging from real-time operations with conditions varying instantaneously, to unit scheduling, commitment and dispatch decisions that occur over hours or days, to long-term planning and resource procurement activities that span months and years. Figure 2 provides an illustration of the operations and planning timeline and required actions.

Figure 2. Operations and Planning Timeline



Wind and solar resource generation levels can vary instantaneously, sometimes by relatively large magnitudes. Voltage and frequency regulation are maintained in short-time steps varying from seconds to minutes, by altering dispatch of regulating reserves, typically with generation resources on Automatic Generation Control (AGC). As higher penetrations of variable energy resources are grid-connected, variability in generation and net load can increase significantly, requiring greater levels of regulating reserves. In assessing variable energy resource integration requirements and costs, PG has focused on understanding operational integration requirements for Regulation Up and Down capacity, in the 10-minute interval. This aspect focuses on changes in operational requirements for BHP, and measurement of fuel and variable operating costs needed to meet those requirements.

As illustrated in Figure 2, longer-term operational and planning/resource procurement actions focus on commitment, dispatch and scheduling of generating units on a day-ahead or longer basis, and development of resource plans and supply procurement processes to assemble generation portfolios that maintain reliable system operation and economic power supply. In these areas, PG has focused on Resource Adequacy and planning requirements associated with having sufficient flexible generation resources on the system, and incremental capital costs required to procure those resources and have sufficient flexible capacity available to meet the short-term operational requirements.

2.5 Reserve Requirements

NERC establishes a set of reliability and operational measures that must be met by Balancing Authorities (BA) to maintain reliable system operations. The NERC compliance requirements are designed to minimize system disturbances and to avoid inadvertent power interchanges between balancing areas and load-serving entities. For BHP, the NERC requirements are administered through the Western Energy Coordinating Council (WECC). WECC develops and implements Regional Reliability Standards and WECC Regional Criteria for the Western Interconnection.

The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to:

- Meet supply requirements for load variations
- Replace generating capacity and energy lost due to forced outages of generation or transmission equipment
- Meet on-demand obligations
- Replace energy lost due to curtailment of interruptible imports
- Balance fluctuations in renewable resource generation

Based on NERC guidance, WECC has established operating reserve requirements for Balancing Authorities in the Western Interconnection, with operating reserves comprised of the following:

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1. **Regulating Reserves**

   - **Regulation Up** – Rapid response load or capacity held in reserve that can be quickly dispatched to increase net power injections on the system

   - **Regulation Down** – Rapid response load or capacity that can be quickly reduced to decrease net power injections on the system

2. **Contingency Reserves**

   - **Spinning Reserves** – Generation reserve capacity from resources currently spinning, that can be dispatched to increase or decrease net power injections within a 10-minute period

   - **Non-Spinning Reserves** – Generation resources not currently spinning, but which can be dispatched to increase net power injections within a 10-minute period

Regulating reserves are controlled by AGC which enables generating units to increase or decrease power output marginally in response to smaller scale system energy imbalances. Contingency reserves are used to correct for larger scale system imbalances caused usually by a loss of a generating unit or transmission line.

2.6 Projected Renewable Resource Additions

BHP currently has one planned solar resource addition anticipated to achieve commercial operation between now and 2025. The 80 MW Fall River solar project is expected to come on-line in 2023. In addition, the BHP team identified additional likely sites and wind, solar and storage capacity additions to be included in assessing variable energy resource integration costs and requirements. Table 3 below lists the renewable and energy storage capacities and locations examined in this assessment. The sites were selected both to recognize areas where project development activity is likely, and to capture benefits of geographical diversification in assessing generation variability for wind and solar resources. As shown, several of the resource portfolios examined include battery energy storage resources, which represent a mitigating technology for managing variable energy production from wind and solar resources.

Table 3. Variable Energy Resource Portfolios

Portfolio	Type	Size (MW)	Location
1	Wind	50	Cheyenne
2	Wind	100	South Gillette
3	Wind	200	North Douglas
4	Solar	50	Cheyenne
5	Solar	100	Gillette
6	Solar	200	Hot Springs
7	Solar + Storage	100 + 40	Cheyenne
8	Solar + Storage	100 + 20	Gillette
9	Solar + Storage	100 + 60	Hot Springs
10	Storage	20	Cheyenne
11	Storage	40	Gillette
12	Storage	60	Hot Springs

As shown in Table 2, the study examines wind, solar and battery energy storage resources at different capacity levels, located in Cheyenne, WY, South Gillette, WY, North Douglass, WY and Hot Springs, SD. The resource portfolios listed in Table 2 were each examined independently in the analyses described below. PG did not examine the resource expansion portfolios in combination, under the scope of this study.

2.7 Study Data Development

The study was completed utilizing detailed generation and load data from several sources. Assessing CPS2 performance and regulating capacity needs requires both actual and forecast power system data, on a 10-minute interval basis and assessing ELCC contributions from wind and solar resources requires detailed generation data on an hourly basis. PG utilized data provided by BHP to the greatest extent possible in completing the analysis and supplemented those data in areas where additional data were needed in order to complete the assessment.

2.7.1 Black Hills Power Data

BHP provided detailed system operations data for the historical year 2019, on both an actual and forecast basis, in addition to forecast data for wind and solar resources expected to achieve commercial operation over the next several years. BHP data utilized in the assessment include:

- Historical and forecast hourly system load data
- Historical hourly and sub-hourly generation and net interchange data
- Historical sub-hourly generation data for existing wind resources
- Forecast hourly data for wind and solar resource additions

Projected capacity factor for wind and solar resources at those three locations are listed in Table 4.

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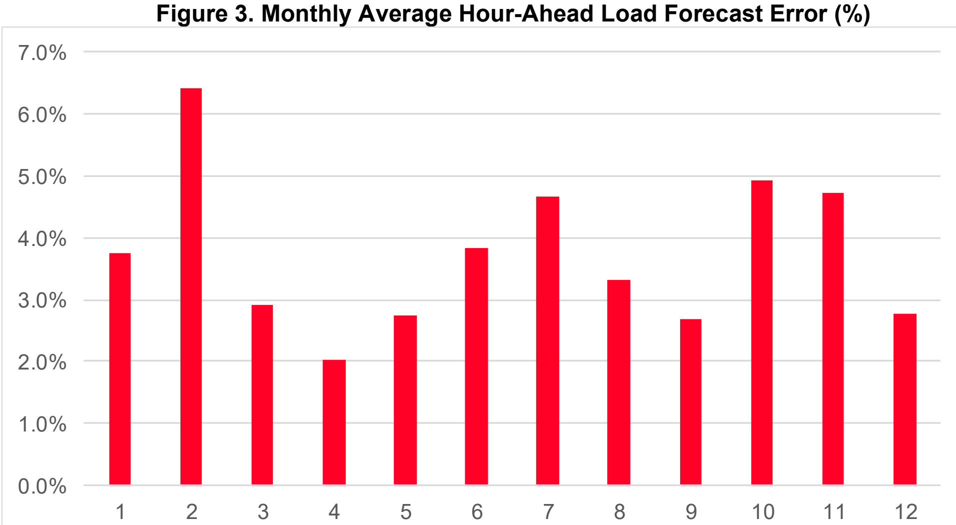
Table 4. Wind and Solar Project Capacity Factor (%)

Site	Wind Capacity Factor (%)	Solar Capacity Factor (%)
Cheyenne, WY	45	26
Gillette, WY	40	24
Douglas, WY	43	NA
Hot Springs, SD	NA	28

PG utilized the BHP 2019 Actual Data, adjusted for load growth and resource additions to 2025. As sub-hourly load forecast data and generation forecast data were not available from BHP, PG developed a sub-hourly load forecast by applying percent differences between hourly actual and forecast data, with the same percentage value for each hour applied to 10-minute intervals within that hour. PG assumed no sub-hourly forecast error for thermal resources.

Figure 3 illustrates monthly average load forecast error, based on the BHP 2019 hourly load data. PG used wind, solar & load forecasting error to calculate the number of regulating reserves required in 2025 to maintain projected reliability requirements.

Figure 3. Monthly Average Hour-Ahead Load Forecast Error (%)



2.7.2 NREL Wind Data

Because 10-minute actual and forecast data were not available for the wind resources, PG researched NREL data availability and obtained data from NREL's Techno-Economic Wind Toolkit dataset for wind resources. The WIND Toolkit includes meteorological conditions and turbine power data for more than 126,000 sites in the continental United States for the years from 2007 to 2013. The data available includes both actual and forecast data for each site. For actual data, wind generation is available at a 5-minute interval. For forecast data, projected wind generation for each site is available on an hourly basis, including 1-hour, 4-hour, 6-hour and 24-

hour day-ahead forecasts. The forecast data were developed by 3Tier, under contract with NREL.

PG selected three sites in the closest possible proximity to Cheyenne, North Douglas and South Gillette. Table 5 lists the location of selected sites, along with the capacity underlying each data series in the NREL data. PG utilized the NREL data and made adjustments to reflect projected sizes of each wind resource as listed earlier in Table 3. PG also converted the NREL 5-minute interval actual wind generation data to a 10-minute interval for completing the CPS2 reliability analysis.

Table 5. NREL Wind Site Data

Site	Site ID	Longitude	Latitude	Capacity (MW)
Cheyenne, WY	63094	-105.108673	41.150742	10
Gillette, WY	103689	-105.943146	44.393757	16
Douglas, WY	96825	-108.575897	43.561279	14

The NREL data set includes data for the years 2007 through 2013. Assessment of the data showed considerable variability between different years. To address that variability, PG used the seven years of NREL data to calculate a set of synthetic annual data for each site. The synthetic shapes were derived by calculating median level actual wind generation for each 10-minute interval in a year, and by calculating median level actual and forecast hourly generation for each hour interval in a year.

While the NREL data included 5-minute resolution actual generation levels, for both the NREL data and for the Black Hills wind data, sub-hourly forecast data were not available. Using available hourly-level forecast data, PG constructed 10-minute interval forecast data for both generation and load, by applying the percentage difference between forecast and actual from the available hourly datasets. This approach introduces some auto-correlation into the analysis of 10-minute data. PG inspected the hourly and sub-hourly data used, and believes it is reasonably representative and suitable for the variable resource integration analysis.

2.7.3 NREL Solar Data

Because 10-minute actual and forecast data were also not available for the solar resources, PG further researched NREL data availability and obtained data from NREL's Solar Power Data for Integration Studies dataset for solar resources. The Solar Power Data for Integration Studies consist of 1 year (2006) of 5-minute solar power and hourly day-ahead forecasts for approximately 6,000 simulated PV plants. Solar power plant locations were determined based on the capacity expansion plan for high-penetration renewables in Phase 2 of the Western Wind and Solar Integration Study and the Eastern Renewable Generation Integration Study. NREL generated the 5-minute data set using the Sub-Hour Irradiance Algorithm. The day-ahead solar forecast data for locations in the western United States were generated by 3TIER based on numerical weather predication simulations for Phase 1 of the Western Wind and Solar Integration Study.

PG selected three sites in the closest possible proximity to Cheyenne and Gillette, WY, and Hot Springs, SD. Table 6 lists the location of selected sites, along with the capacity underlying each

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data series and projected capacity factor implicit in the NREL data. PG utilized the NREL data with adjustments to reflect projected sizes of each solar resource as listed earlier in Table 3. PG also converted the NREL 5-minute interval actual wind generation data to a 10-minute interval for completing the CPS2 reliability analysis.

Table 6. NREL Solar Site Data

Site	Site ID	Longitude	Latitude	Capacity (MW)
Cheyenne, WY	63094	-104.85	41.15	9
Gillette, WY	103689	-105.55	44.35	6
Hot Springs, SD	96825	-102.95	43.45	14

While the NREL data included 5-minute resolution actual generation levels, for both the NREL data and for the Black Hills solar data, sub-hourly forecast data were not available. Following the same approach that had been developed for the wind data, PG again used available hourly-level forecast data to construct 10-minute interval forecast data for solar generation by applying the percentage difference between forecast and actual from the available hourly datasets.

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3 Variable Energy Resource Integration Requirements and Costs

3.1 Overview

A number of studies have been completed examining wind and solar resource integration needs and costs, including large-scale studies of the Western U.S. completed under NREL direction and funding. A common methodology used in renewable integration studies across the industry is to focus on changes in regulation capacity needed to offset generation uncertainty created due to the intermittent nature of generation from wind and solar resources. It is well-recognized that the extent to which renewable resource variability becomes an issue will depend on numerous system-specific factors including power system size and the proportion of generation that is variable, the potential output of the resources, and the ability to forecast that output.

This study focused on the operating reserves required to integrate wind and solar in dispatch operations. Specifically, this study considered the operating reserves that can respond to changes in system ACE in a 10-minute timeframe to ensure reliable system operation. The system ACE is measured as the difference in the scheduled generation and load versus the actual generation and load for each 10-minute clock interval. Under-forecasting the load can be offset by under-forecasting of the wind or solar. Conversely, over-forecasting of the load will be exacerbated by under-forecasting of the wind or solar and cause a higher frequency bias, unless AGC or the system operator can take corrective action.

To assess 10-minute regulating reserves, PG developed an approach that approximates NERC CPS2 for maintaining balancing area reliability. The NERC CPS2 criterion is a statistical measure of the ACE measured in 10-minute clock intervals. The CPS2 reliability criterion stipulates that the system ACE must be within a tolerable deviation range (defined as the L_{10}) for 90 percent of the 10-minute clock intervals for each month. PG developed an Excel model ("Variable-Resource Integration model") to calculate the difference between the predicted and actual output of the wind and solar energy on the BHP system in 2025.

The increase in 10-minute regulating reserves required to keep the number of future CPS2 errors within either a 5 percentile band or a 2 percentile band was used as the basis to estimate incremental Regulation Up and Regulation Down requirements associated with different variable energy resource expansion options, and to assess variable energy resource integration costs[1].

[1] Note that the 5 percentile and 2 percentile bands are more conservative than the NERC standard requiring ACE to be within required limits at least 90 percent of the time. There are two factors supporting the use of higher, more conservative performance levels. First, examination of individual years of NREL wind data reveals considerable variation in actual and forecast wind generation levels, so under varying meteorological conditions, regulation needs will vary upward. Second, the approach utilized by PG in this study mirrors an approach utilized by Black & Veatch in completing a similar study of the Black Hills Colorado system in 2015, which will facilitate consistency in resource planning approach and decisions across the Black Hills Corporation organization.

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The impact of variation in load was also reflected in the CPS2 model. Actual 5-minute and hourly load data and forecasts provided by BHP were used to develop ACE estimates, along with the wind and solar data.

3.2 Black Hills Power Baseline Regulation Requirements

As indicated above, PG completed an assessment of CPS2 performance for BHP, both based on its current power system, with load and supply resources expected to be in place in 2025, and with additional wind, solar and storage resource additions. For this analysis, ACE was calculated as:

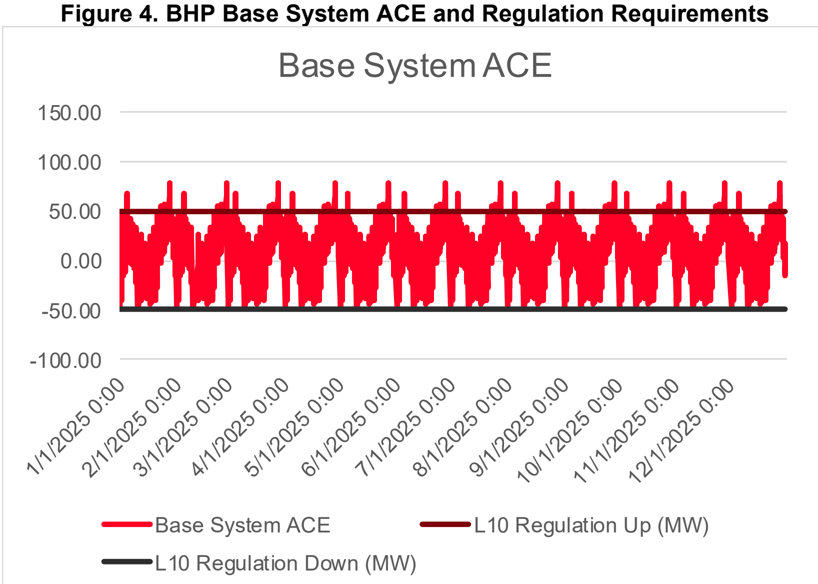
$$
\begin{aligned}
ACE_{\mathrm{MW}} = (&Actual\ Load - Forecast\ Load) \\
&+ (Actual\ Thermal\ Generation - Forecast\ Thermal\ Generation) \\
&+ (Actual\ Wind\ Generation - Forecast\ Wind\ Generation) \\
&+ (Actual\ Solar\ Generation - Forecast\ Solar\ Generation)
\end{aligned}
$$

ACE values were first calculated for each 10-minute interval for the year 2025, based on BHP's existing system, including load growth and resource additions planned through 2025.

For each 10-minute interval, the calculated ACE values were compared to projected NERC L_{10} values. L_{10} is a guideline metric calculated by NERC, which expresses balancing capacity targets as a function of peak demand. If the ACE value exceeded the projected L_{10} value, by a positive quantity, then that period was flagged as a Regulation Up violation, and if the ACE value was less than the negative of the projected L_{10} value, then that period was flagged as a Regulation Down violation. Based on BHP's projected 2025 load, the NERC L_{10} values are 49 MW, which were interpreted as Regulation Up and down requirements for BHP's 2025 power system, absent any additional supply resource additions.

Comparing the estimated ACE values to L_{10}-based Regulation Up and Regulation Down requirements, PG estimated that at a 95th percentile CPS2 compliance level, the BHP 2025 power system will have both Regulation Up and Regulation Down requirements of 49 MW based on its forecast load, current thermal resources, and current and projected renewable resources. At a 98th percentile CPS2 compliance level, the BHP 2025 power system would have a slightly higher 55 MW Regulation Up requirement, and 50 MW Regulation Down requirement. As BHP is not an independent balancing authority subject directly to NERC compliance, these values can be interpreted as guideline and baseline metrics for BHP to consider in its resource planning and supply procurement activities.

Figure 4. BHP Base System ACE and Regulation Requirements



As shown in Figure 4, there are a small number of hours where ACE values exceed the Regulation Up requirement, which is permissible under the CPS2 metric. Those exceedances occur less than two percent of the 10-minute intervals shown. Under the base system, Regulation Down requirements do not exceed the lower level L_{10} band.

3.3 Black Hills Power Incremental Regulation Requirements

For each of the renewable resource portfolio additions, PG developed estimates of incremental regulation requirements at both a 95 percent and 98 percent CPS2 performance level. Table 7 summarizes estimated incremental regulation requirements for each resource portfolio examined. As shown, incremental Regulation Up quantities vary from zero MW to 50 MW. Because wind generation forecast error is much more volatile than solar, the incremental regulation requirements are higher for wind resources.

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Table 7. Estimated BHP Regulation Requirements

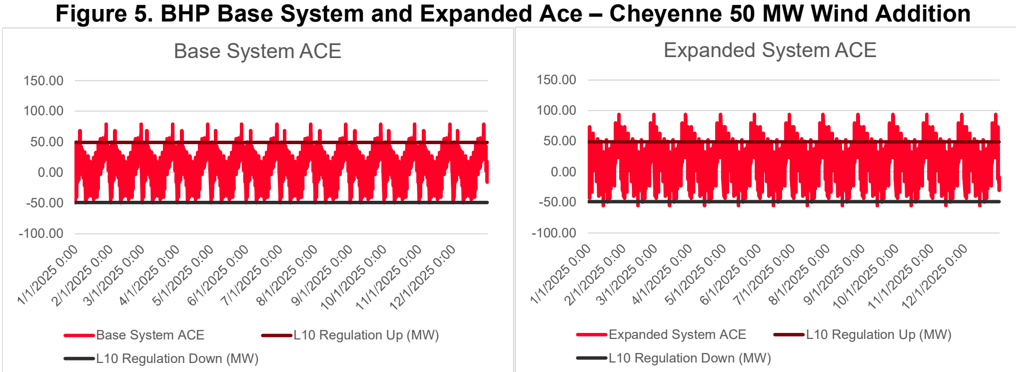
Portfolio	Type	Size (MW)	Location	95% CPS2: Incremental Regulation Up (MW)	95% CPS2: Incremental Regulation Down (MW)	98% CPS2: Incremental Regulation Up (MW)	98% CPS2: Incremental Regulation Down (MW)
Existing System				55	49	49	55
1	Wind	50	Cheyenne	8	0	24	0
2	Wind	100	S. Gillette	7	6	26	22
3	Wind	200	N. Douglas	25	32	50	40
4	Solar	50	Cheyenne	0	0	7	1
5	Solar	100	Gillette	0	0	10	1
6	Solar	200	Hot Springs	1	0	11	1
7	Solar + Storage	100 + 40	Cheyenne	0	0	0	1
8	Solar + Storage	100 + 20	Gillette	0	0	0	1
9	Solar + Storage	100 + 60	Hot Springs	0	0	0	1
10	Storage	20	Cheyenne	0	0	0	1
11	Storage	40	Gillette	0	0	0	1
12	Storage	60	Hot Springs	0	0	0	1

3.3.1 Resource Portfolio 1: 50 MW Wind Addition at Cheyenne, WY

Resource Portfolio 1 includes a 50 MW wind resource addition at Cheyenne, WY, with a wind regime similar to existing BHP wind generators. Figure 5 provides a comparison of system ACE values under the base and expanded system. As shown, adding a 50 MW wind resource at Cheyenne results in higher positive ACE values, approaching 100 MW in some hours, and exceeding the L_{10} Regulation Up requirement with greater frequency.

For the Cheyenne wind resource addition, PG estimates that BHP would require 8 MW of additional Regulation Up capacity to achieve 95 percent CPS2 compliance, and 24 MW of additional Regulation Up capacity to achieve 98 percent CPS2 compliance. The magnitude and frequency of Regulation Down exceedances are minor for this resource portfolio, and do not require any additional Regulation Down capacity.

Figure 5. BHP Base System and Expanded Ace – Cheyenne 50 MW Wind Addition

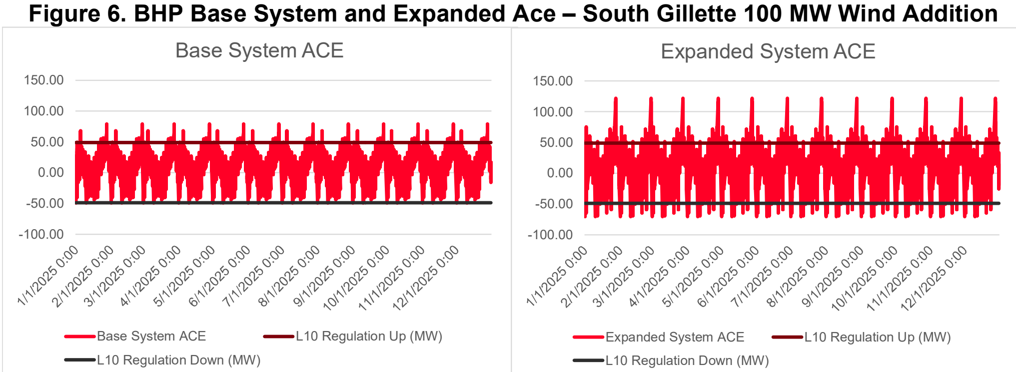


3.3.2 Resource Portfolio 2: 100 MW Wind Addition at South Gillette, WY

Resource Portfolio 2 doubles the assumed wind addition at South Gillette, WY, to 100 MW. Figure 6 provides a comparison of system ACE values under the base and expanded system for this wind resource addition. As shown, with the 100 MW wind addition, the frequency of ACE exceeding the Regulation Up L_{10} level increases, and some upward ACE values approach 125 MW, which is 75 MW higher than the L_{10} Regulation Up band.

For the South Gillette 100 MW wind resource addition, PG estimates that BHP would require 7 MW of additional Regulation Up capacity to achieve 95 percent CPS2 compliance, and 26 MW of additional Regulation Up capacity to achieve 98 percent CPS2 compliance. There is also a greater frequency of Regulation Down exceedances. The 100 MW wind addition at Gillette is estimated to require 6 MW of incremental Regulation Down capacity to meet the 95 percent CPS2 standard, and 22 MW of Regulation Down capacity to meet the 98 percent standard.

Figure 6. BHP Base System and Expanded Ace – South Gillette 100 MW Wind Addition



3.3.3 Resource Portfolio 3: 200 MW Wind Addition at North Douglas, WY

Resource Portfolio 3 again doubles the assumed wind addition, to 200 MW, in this case at North Douglas, WY. Figure 7 provides a comparison of system ACE values under the base and expanded system for this wind resource addition. As shown, with the 200 MW wind addition, the frequency of ACE exceeding the Regulation Up L_{10} level further increases, with a wider range of upward ACE exceedance levels, and some upward ACE values approaching the full 200 MW.

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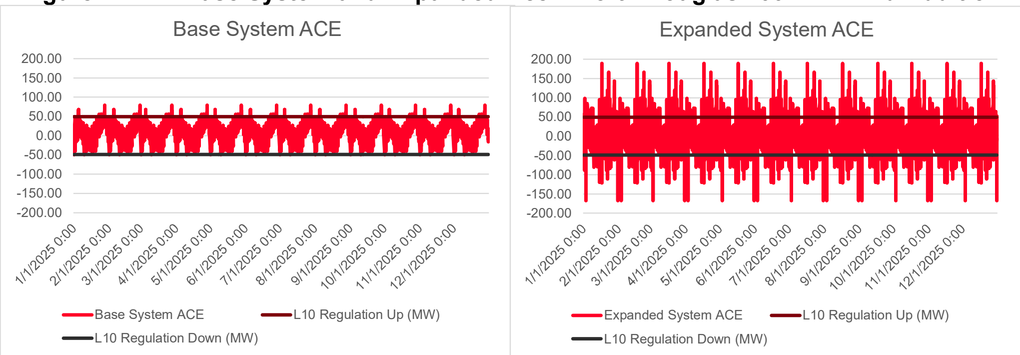
For the North Douglas 200 MW wind resource addition, PG estimates that BHP would require 25 MW of additional Regulation Up capacity to achieve 95 percent CPS2 compliance, and 50 MW of additional Regulation Up capacity to achieve 98 percent CPS2 compliance. The Regulation Down exceedances are more frequent and of greater magnitude with a 200 MW wind addition. PG estimates that 32 MW of incremental Regulation Down capacity to meet the 95 percent CPS2 standard, and 40 MW of Regulation Down capacity to meet the 98 percent standard.

Figure 7. BHP Base System and Expanded Ace – North Douglas 200 MW Wind Addition

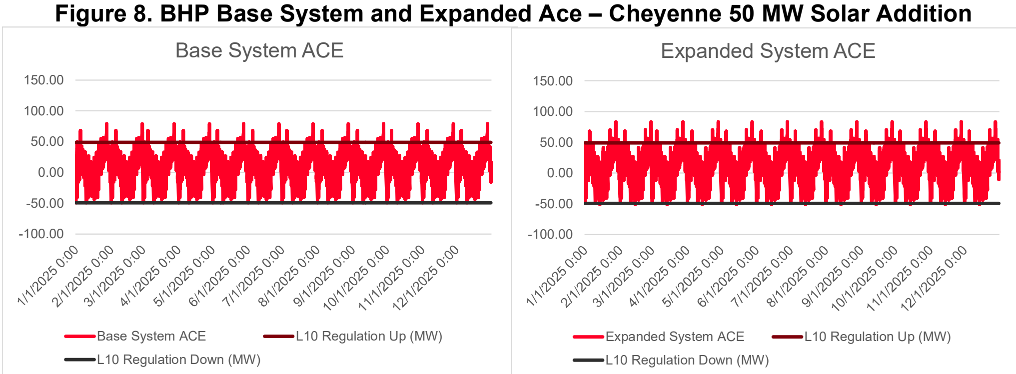


3.3.4 Resource Portfolio 4: 50 MW Solar Addition at Cheyenne, WY

Resource Portfolio 4 assumes a 50 MW solar resource addition at Cheyenne, WY. Figure 8 provides a comparison of system ACE values under the base and expanded system for this solar resource addition. As shown, with the 50 MW solar addition, there is an increase in the frequency of ACE exceeding the Regulation Up L_{10} level, but the frequency and magnitude of those exceedances are relatively low. There are only minor instances of ACE levels exceeding the L_{10} Regulation Down band. In general, the forecast error for solar resources is substantially lower than for wind, so the frequency and magnitude of ACE exceedances is lower.

For the Cheyenne 50 MW solar resource addition, PG estimates no incremental Regulation Up capacity would be required to achieve 95 percent CPS2 compliance, and 7 MW of additional Regulation Up capacity would be required to achieve 98 percent CPS2 compliance. The Regulation Down exceedances are minor, with no incremental Regulation Down capacity to meet the 95 percent CPS2 standard, and 1 MW to meet the 98 percent standard.

Figure 8. BHP Base System and Expanded Ace – Cheyenne 50 MW Solar Addition

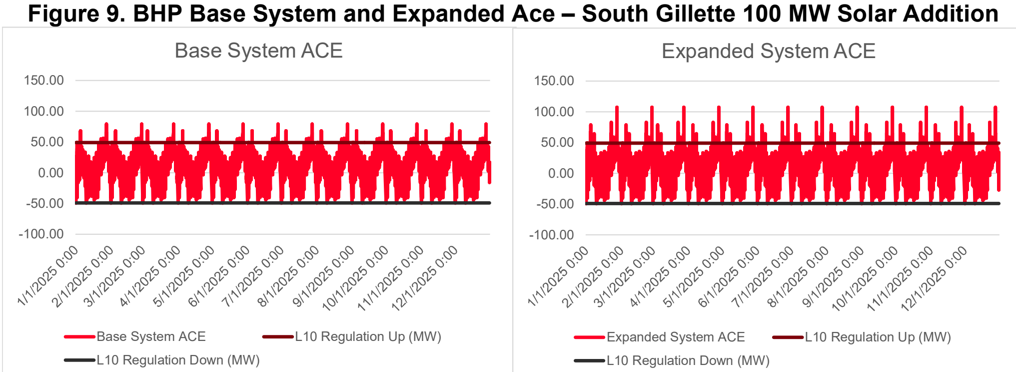


3.3.5 Resource Portfolio 5: 100 MW Solar Addition at South Gillette, WY

Resource Portfolio 5 assumes a 100 MW solar resource addition at South Gillette, WY. Figure 9 provides a comparison of system ACE values under the base and expanded system for this solar resource addition. As shown, with the 100 MW solar addition, there is an increase in the frequency of ACE exceeding the Regulation Up L_{10} level, with some upward ACE values approaching 100 MW, which is 60 MW above the L_{10} Regulation Up band. There are only minor instances of ACE levels exceeding the L_{10} Regulation Down band.

For the South Gillette 100 MW solar resource addition, PG again estimates no incremental Regulation Up capacity would be required to achieve 95 percent CPS2 compliance, and 10 MW of additional Regulation Up capacity would be required to achieve 98 percent CPS2 compliance. The Regulation Down exceedances continue to be minor, with no incremental Regulation Down capacity to meet the 95 percent CPS2 standard, and 1 MW to meet the 98 percent standard.

Figure 9. BHP Base System and Expanded Ace – South Gillette 100 MW Solar Addition



3.3.6 Resource Portfolio 6: 200 MW Solar Addition at Hot Springs, SD

Resource Portfolio 6 assumes a 200 MW solar resource addition at Hot Springs, SD. Figure 10 provides a comparison of system ACE values under the base and expanded system for this solar resource addition. As shown, with the 200 MW solar addition, there is a further increase in the frequency of ACE exceeding the Regulation Up L_{10} level, with some upward ACE values

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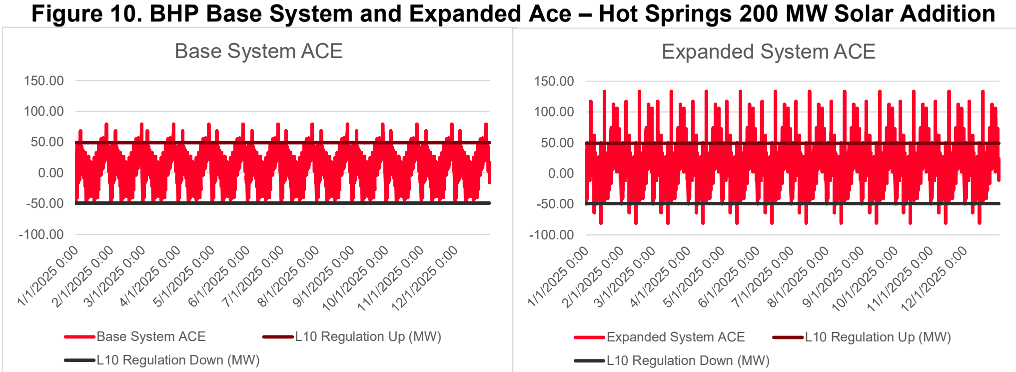
approaching 140 MW, which is 90 MW above the L_{10} Regulation Up band. There are only minor instances of ACE levels exceeding the L_{10} Regulation Down band.

For the Hot Springs 200 MW solar resource addition, PG again estimates that BHP would require 1 MW of additional Regulation Up capacity to achieve 95 percent CPS2 compliance, and 11 MW of additional Regulation Up capacity would be required to achieve 98 percent CPS2 compliance. This can be seen in Figure 10, where there the magnitude of ACE Regulation Up exceedances are greater, with upward ACE values approaching 130 MW, the relative frequency of such exceedances is still relatively moderate. The Regulation Down exceedances continue to be minor, with no incremental Regulation Down capacity to meet the 95 percent CPS2 standard, and 1 MW to meet the 98 percent standard.

Figure 10. BHP Base System and Expanded Ace – Hot Springs 200 MW Solar Addition



3.3.7 Resource Portfolio 7: 100 MW Solar Addition Plus 40 MW Battery Energy Storage at Cheyenne

Resource Portfolio 7 assumes a 100 MW solar resource addition combined with a 40 MW Battery Energy Storage (BESS)[2] resource at Cheyenne, WY.

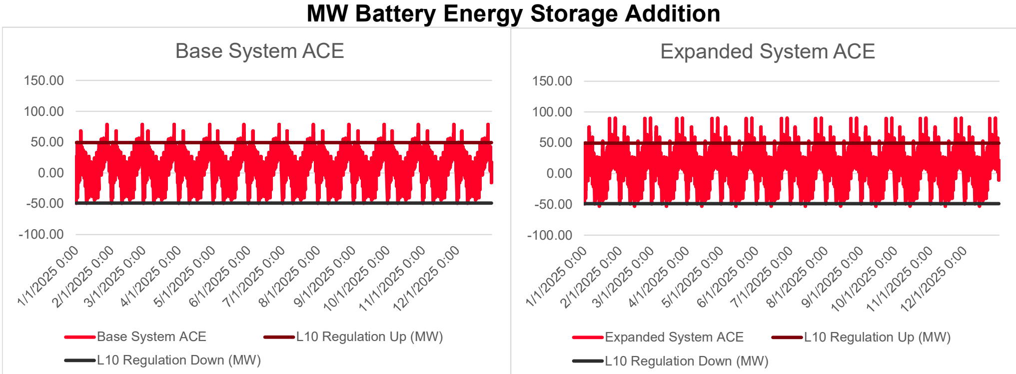
Figure 11 provides a comparison of system ACE values under the base and expanded system for this solar resource addition. As shown, with the 100 MW solar addition, there is an increase in the frequency of ACE exceeding the Regulation Up L_{10} level, with some upward ACE values approaching 90 MW, which is 40 MW above the L_{10} Regulation Up band. There are only minor instances of ACE levels exceeding the L_{10} Regulation Down band.

For the 100 MW solar resource addition, PG again estimates no incremental Regulation Up capacity would be required to achieve 95 percent CPS2 compliance, and 8 MW of additional Regulation Up capacity would be required to achieve 98 percent CPS2 compliance. The 40 MW battery addition is sufficient to cover that incremental 8 MW of regulation capacity, so on net, PG estimates no incremental Regulation Up requirement for the combined solar/storage project. The Regulation Down exceedances are minor, with no incremental Regulation Down capacity to meet the 95 percent CPS2 standard, and 1 MW to meet the 98 percent standard. That Regulation

[2] Energy storage resources in the solar plus BESS portfolios are assumed to exclusively charge from the solar resource that they are paired with in order to be eligible for the investment tax credit.

Down capacity can also be met with the battery, so on net, no incremental regulation capacity is needed.

Figure 11. BHP Base System and Expanded Ace – Cheyenne, WY 100 MW Solar Plus 40 MW Battery Energy Storage Addition



3.3.8 Resource Portfolio 8: 100 MW Solar Addition Plus 20 MW Battery Energy Storage at South Gillette

Resource Portfolio 8 assumes a 100 MW solar resource addition combined with a 20 MW Battery Energy Storage (BESS) resource at Gillette, WY. This portfolio essentially adds a 20 MW battery to Resource Portfolio 5 discussed above.

Figure 12 provides a comparison of system ACE values under the base and expanded system for this solar and battery resource addition. As shown, with the 100 MW solar addition, there is an increase in the frequency of ACE exceeding the Regulation Up L_{10} level, with some upward ACE values just over 100 MW, which is 50 MW above the L_{10} Regulation Up band. There are only minor instances of ACE levels exceeding the L_{10} Regulation Down band.

For the 100 MW solar resource addition, PG again estimates no incremental Regulation Up capacity would be required to achieve 95 percent CPS2 compliance, and 10 MW of additional Regulation Up capacity would be required to achieve 98 percent CPS2 compliance. The 20 MW battery addition is sufficient to cover that incremental 10 MW of regulation capacity, so on net, PG estimates no incremental Regulation Up requirement for the combined solar/storage project. The Regulation Down exceedances are minor, with no incremental Regulation Down capacity to meet the 95 percent CPS2 standard, and 1 MW to meet the 98 percent standard. That Regulation Down capacity can also be met with the battery, so on net, no incremental regulation capacity is needed.

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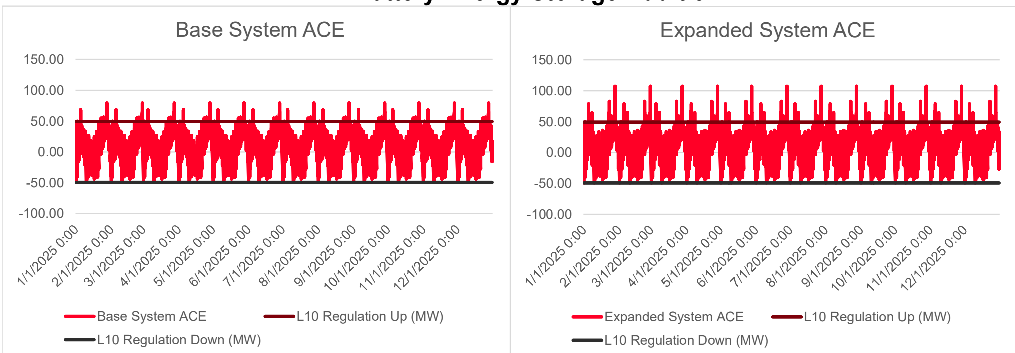
Figure 12. BHP Base System and Expanded Ace – South Gillette, WY 100 MW Solar Plus 20 MW Battery Energy Storage Addition

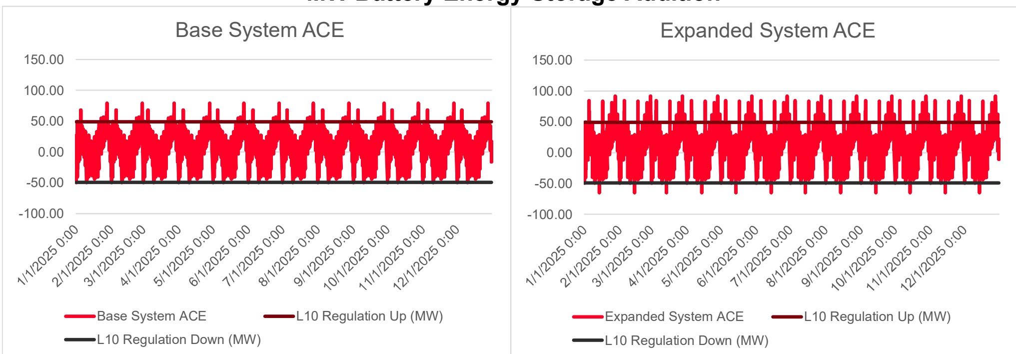


3.3.9 Resource Portfolio 9: 100 MW Solar Addition Plus 60 MW Battery Energy Storage at Hot Springs, SD

Resource Portfolio 9 assumes a 100 MW solar resource addition plus a 60 MW Battery Energy Storage (BESS) resource at Hot Springs, SD. Figure 13 provides a comparison of system ACE values under the base and expanded system for this solar and battery resource addition. As shown, with the 100 MW solar addition, there is an increase in the frequency of ACE exceeding the Regulation Up L_{10} level, with some upward ACE values just over 90 MW, which is 40 MW above the L_{10} Regulation Up band. There are a small number of instances of ACE levels exceeding the L_{10} Regulation Down band.

For the 100 MW solar resource addition, PG again estimates no incremental Regulation Up capacity would be required to achieve 95 percent CPS2 compliance, and 9 MW of additional Regulation Up capacity would be required to achieve 98 percent CPS2 compliance. The 60 MW battery addition is sufficient to cover that incremental 10 MW of regulation capacity, so on net, PG estimates no incremental Regulation Up requirement for the combined solar/storage project. The Regulation Down exceedances are minor, with no incremental Regulation Down capacity to meet the 95 percent CPS2 standard, and 1 MW to meet the 98 percent standard. That Regulation Down capacity can also be met with the battery, so on net, no incremental regulation capacity is needed.

Figure 13. BHP Base System and Expanded Ace – Hot Springs, SD 100 MW Solar Plus 60 MW Battery Energy Storage Addition



3.3.10 Resource Portfolios 10, 11 and 12: 20 MW, 40 MW and 60 MW Battery Storage Additions at Cheyenne, Gillette and Hot Springs

Resource Portfolios 10, 11, and 12 assume stand-alone Battery Energy Storage installations at Cheyenne, WY, Gillette, WY and Hot Springs, SD, respectively. PG assumed that a stand-alone battery installation would not create any incremental forecast error that would contribute to ACE, and as such, there is zero incremental Regulation Up or Regulation Down requirements due to installation of stand-alone battery storage facilities.

3.4 Black Hills Power Incremental Regulation Cost

For each of the renewable resource portfolio additions listed above in Table 7, PG utilized the Portfolio Optimization (PO) model to simulate the BHP power system, including each resource addition. PG also modelled incremental Regulation Up and Regulation Down capacity requirements for each of the resource portfolios as outlined in Table 7.

For each PO simulation, the difference in total system production costs between each portfolio's simulation with and without the incremental regulation capacity was used to develop estimated cost per MWh for meeting the incremental Regulation Up and Down requirements. PG also evaluated the need for additional flexible capacity, and associated cost in cases where incremental capacity is needed.

3.4.1 BHP Thermal Station Ancillary Services Capabilities

To model the regulation requirements, PG specified two ancillary services variables:

- AS1 was defined as Regulation Up and AS2 was defined as Regulation Down. These variables were modeled to reflect incremental Regulation Up and Regulation Down requirements for each portfolio.
- In the PO model, the A/S Contribution Type was set to On-line Only for all Thermal units used to provide AS1 and AS2.

PG completed an assessment of the existing BHP generation portfolio and specified nine thermal generating units as having capability to provide Regulation Up and Regulation Down capacity.

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Incremental battery storage resources included in Portfolios 7 through 12 would also have capability to provide regulation capacity. For existing thermal resources, ancillary services capabilities reflected in the PO simulations are listed in Table 8.

Table 8. Thermal Station Ancillary Services Capabilities

Station	Can provide Regulation up or down (Y/N)	Capacity Minimum (MW)	Capacity Maximum (MW)	Notes
1_CT BF1	Yes	2	20	1-hour minimum run time.
1_CT BF2	Yes	2	20	1-hour minimum run time.
1_CT BF3	Yes	2	20	1-hour minimum run time. Black Start Unit.
1_CT BF4	Yes	2	20	1-hour minimum run time. Black Start Unit.
1_CT Lange	Yes	20	38	1-hour minimum run time (2 hours when temperature is below 20 degrees).
1_LMCC CPGS BHP	Yes	1x1 - 20 2x1 - 50	1x1 - 48 2x1 - 95	2-hour minimum run time.
1_Neil Simpson2	Yes	60	80	
1_Wygen III	Yes	70	103	

3.4.2 BHP Incremental Regulation Cost

Estimated costs for BHP to carry additional Regulation Up and Regulation Down capacity are listed below in Table 9. These cost estimates reflect changes in BHP operating cost as the system unit commitment and dispatch is altered to reflect an increased Regulation Up and Down capacity operating reserve requirement. The costs in Table 9 do not reflect any capital related cost needed to procure additional flexible regulation capacity. As shown, PG estimated incremental regulation costs assuming Regulation Up and Down quantities needed to meet the 98 percentile CPS2 standard. For resource portfolios that include only battery storage projects, PG has not estimated an incremental regulation requirement or cost, as storage only resources are unlikely to cause incremental ACE deviations.

Estimated regulation costs for wind additions vary by location and project size, ranging from $6.56/MWh for a 100 MW wind resource at South Gillette, to $10.17/MWh for a 50 MW wind resource at Cheyenne, and $11.12/MWh for a 200 MW wind resource at North Douglas.

For solar resource additions, incremental regulation costs range from $1.57/MWh for a 200 MW solar resource at Hot Springs, WY, to $4.63/MWh for a 100 MW solar resource at Gillette, to $5.38/MWh for a 50 MW solar resource at Cheyenne. For resource portfolios including solar with battery storage, PG concluded that incremental Regulation Up requirements could be met by the installed battery capacity and stored energy, in which case the incremental cost shown is to cover Regulation Down requirements only.[3]

BHP also has an option to procure regulation from WAPA, through its Open Access Transmission Tariff (OATT) at a lower cost. WAPA's current tariff offers regulation service for a fixed cost of $0.303/kW/Month for wind resources, and $0.205/kW/Month for solar resources. At a 40% annual average wind capacity factor, the WAPA regulation cost is equivalent to $1.04/MWh for wind resources, and at a 25% annual average capacity factor for solar, it would be equivalent to $1.12/MWh for solar resources.

Table 9. Incremental BHP Regulating Reserve Cost

Portfolio	Type	Size (MW)	Location	98% CPS2: Incremental Regulation Up (MW)	98% CPS2: Incremental Regulation Down (MW)	Regulation Cost – BHP Generation ($/MWh)	Regulation Cost – WAPA Tariff ($/kW/Mo)
Existing System				55	50		
1	Wind	50	Cheyenne	24	0	$10.17	$0.303
2	Wind	100	S. Gillette	26	22	$6.56	$0.303
3	Wind	200	N. Douglas	50	40	$11.12	$0.303
4	Solar	50	Cheyenne	7	1	$5.38	$0.205
5	Solar	100	Gillette	10	1	$4.63	$0.205
6	Solar	200	Hot Springs	11	1	$1.57	$0.205
7	Solar + Storage	100 + 40	Cheyenne	0	1	$0.02	$0.205
8	Solar + Storage	100 + 20	Gillette	0	1	$0.03	$0.205
9	Solar + Storage	100 + 60	Hot Springs	0	1	$0.02	$0.205
10	Storage	20	Cheyenne	0	1	N/A	
11	Storage	40	Gillette	0	1	N/A	
12	Storage	60	Hot Springs	0	1	N/A	

3.4.3 The Dynamics of Providing Regulation Capacity on the BHP System

In completing the PO simulations, PG examined unit operations for the BHP generation portfolio to better understand the dynamics of meeting incremental regulation requirements. Figure 14 provides an illustration of thermal resource contributions to a 50 MW Regulation Up requirement on the BHP system. As shown, Regulation Up Ancillary Services are provided primarily by Neil Simpson 2 Steam, Wygen III and LMCC1 CPGS generators. The Ben French CTs and the Lange CT operate and provide Regulation Up capacity during more limited time periods when more economical units are offline for planned maintenance or forced outage.

[3] If the battery storage facility is not operated to meet the incremental regulation requirement, then total regulation/integration costs for those three portfolios would be higher, estimated at $2.56/MWh for Resource Portfolio 7, $3.41/MWh for Resource Portfolio 8, and $2.80/MWh for Resource Portfolio 9.

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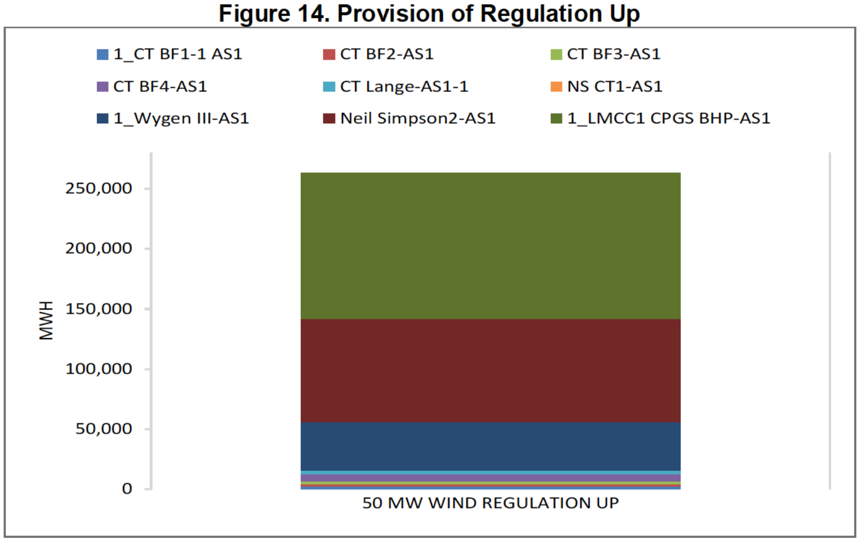
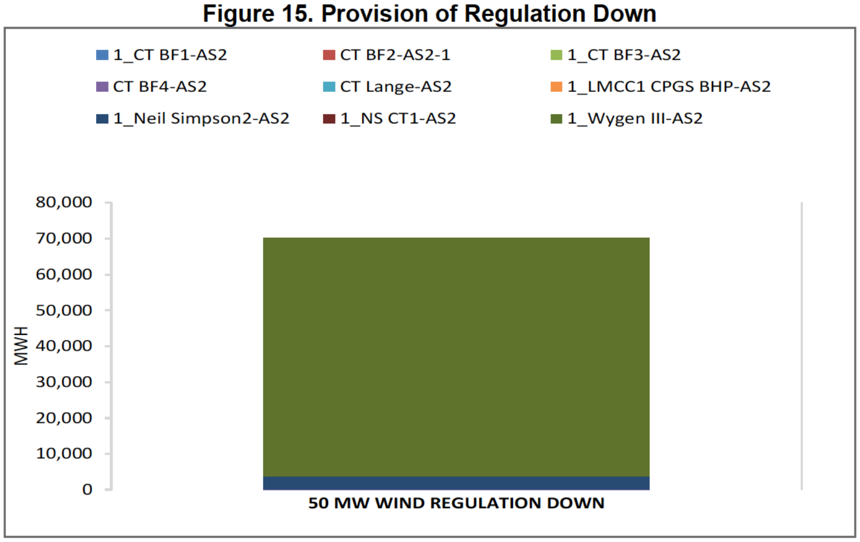
Figure 14. Provision of Regulation Up



Regulation Down ancillary services are provided primarily by the Wygen III unit. Figure 15 provides an illustration of thermal resources providing 50 MW of Regulation Down services on the BHP system. As shown, a large share of such services are provided by Wygen III, with a small portion of additional Regulation Down services provided by Neil Simpson II.

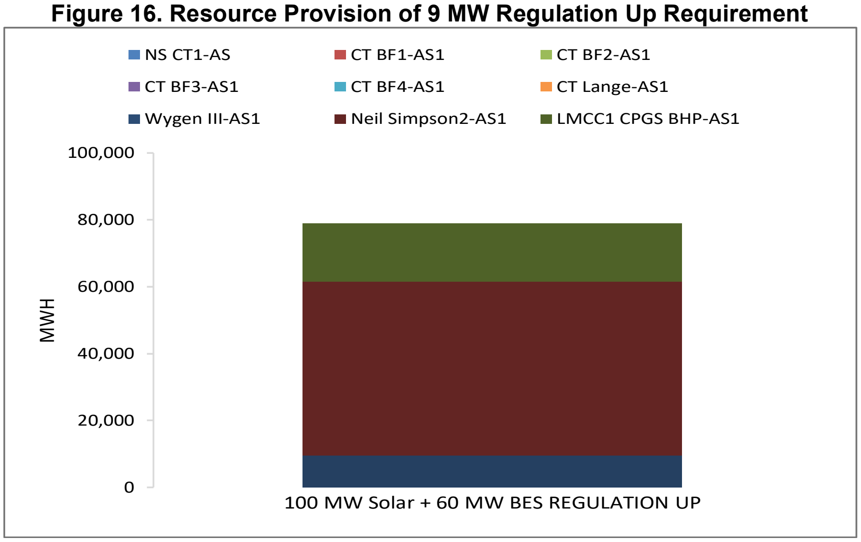
Figure 15. Provision of Regulation Down



Changes in operating costs and the cost of providing regulating reserves are sensitive to the magnitude of additional Regulation Up capacity that BHP will be required to carry with each of the Resource Portfolios. For example, for Resource Portfolios requiring incremental Regulation Up Capacity in the 8 to 10 MW range, such as for the solar resource expansions, the balance of

Regulation Up capacity can be supplied by Neil Simpson 2, at a relatively low cost. Figure 16 provides an illustration of thermal resource contribution to provide 9 MW of Regulation Up capacity. With that level of incremental regulation requirement, most of the Regulation Up provision occurs from Neil Simpson 2, and the incremental system cost is less than $3/MWh.

Figure 16. Resource Provision of 9 MW Regulation Up Requirement



In contrast, with a 30 MW incremental Regulation Up requirement, over 50 percent of regulation capacity on the BHP system is provided by the natural gas-fueled LMCC1 CPGS. The incremental operating cost and change in BHP system costs is considerably higher with that level of regulation requirement, with incremental regulation costs exceeding $10/MWh.

Figure 17 provides an illustration of thermal unit regulation capacity contribution under those conditions.

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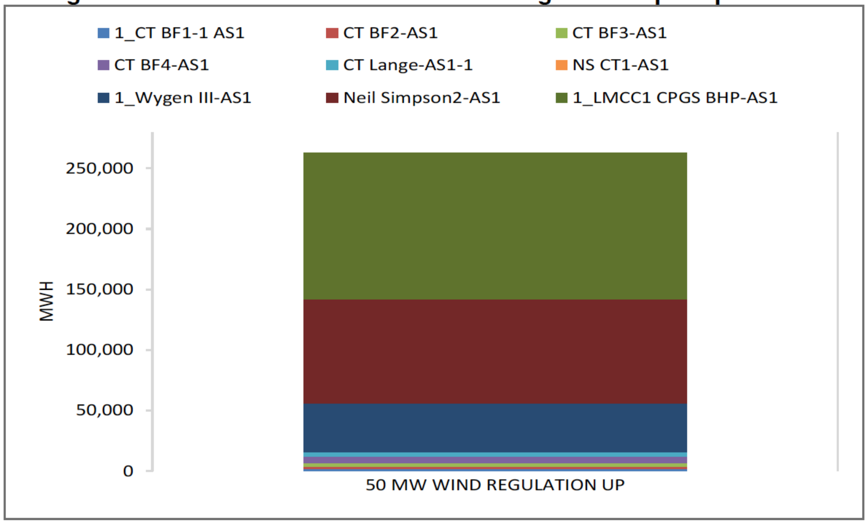
Figure 17. Resource Provision of 30 MW Regulation Up Requirement



3.4.4 Flexible Capacity Requirements

In addition to assessing incremental Regulation Up and Regulation Down costs and quantities likely to be incurred due to changes in BHP operating costs, PG also completed an assessment of whether BHP is likely to require additional flexible capacity to integrate the Resource Portfolios. PG completed this assessment by applying a methodology originally developed by the California Independent System Operator (CAISO) to assess flexible capacity requirements[4].

Under that approach, the need for Flexible Capacity Need is determined by examining the capacity of the most severe single contingency and the monthly maximum contiguous 3-hour ramp on the BHP system. At 103 MW, Wygen III represents the single largest contingency on the BHP system. PG created an hourly 2025 Net Load forecast for the existing system by subtracting BHP's existing VER generation forecast from the BHP Full load forecast. PG then calculated the maximum three-hour Net Load contiguous ramp for each month of 2025. Results of those calculation are illustrated below in Figure 18.

[4] See, http://www.caiso.com/Documents/Final2020FlexibleCapacityNeedsAssessment.pdf

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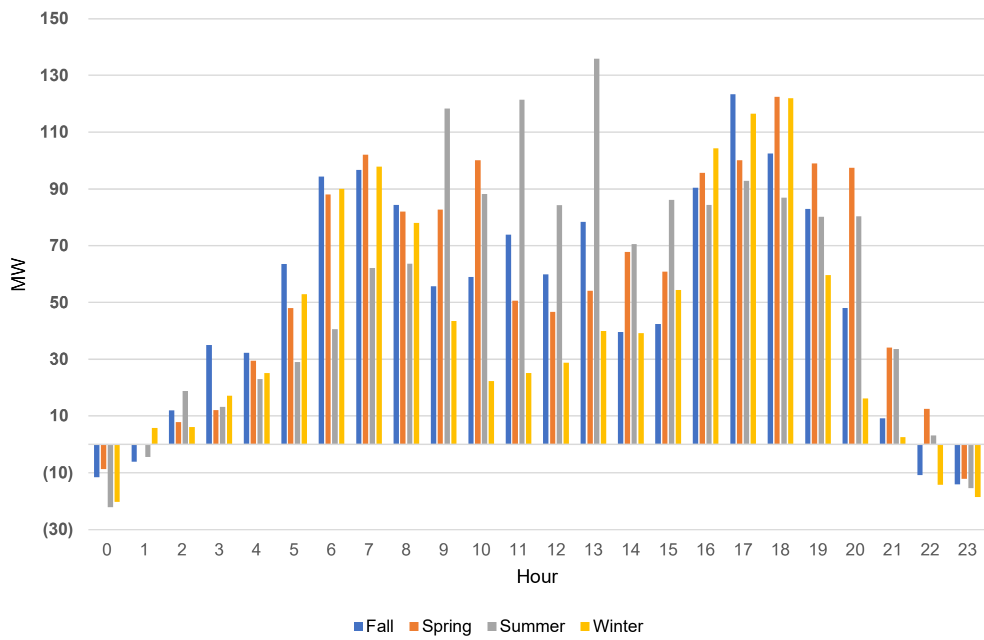
Figure 18. Maximum Net 3-Hour Ramp – Existing BHP System



Using the net 3-hour ramp calculations, incremental Flexible Capacity requirements were estimated by subtracting Black Hills Power's existing Flexible Capacity (excluding the largest contingency, Wygen III – 293 MW from the Maximum Flexible Capacity Need.

Table 8 illustrates results of this assessment. As shown, three of the Resource Portfolios require procurement of additional Flexible Capacity, including Portfolio 3, which creates a Flexible Capacity need of 86 MW, Portfolio 5 which creates a 16 MW Flexible Capacity need, and Portfolio 6, which creates a 118 MW Flexible Capacity need. The cost of flexible capacity is typically tied to the carrying cost of flexible peaking capacity. Black & Veatch is currently completing a study of busbar costs for new generation on the BHP system, and those costs and the flexible capacity requirements identified above will be reflected in BHP's Integrated Resource Plan development for Resource Portfolios 3, 5 and 6.

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Table 10. BHP Flexible Capacity Need

Portfolio	Type	Size (MW)	Location	Max Three-Hour Ramp (MW)	Incremental Three-Hour Max Ramp (MW)	Max Flexible Capacity Need (MW)	Resource Need (MW)
Existing System				55	136		239
1	Wind	50	Cheyenne	162	26	265	0
2	Wind	100	S. Gillette	172	36	275	0
3	Wind	200	N. Douglas	276	140	379	86
4	Solar	50	Cheyenne	166	30	269	0
5	Solar	100	Gillette	206	70	309	16
6	Solar	200	Hot Springs	308	172	411	118
7	Solar + Storage	100 + 40	Cheyenne	187	51	272	0
8	Solar + Storage	100 + 20	Gillette	187	51	289	0
9	Solar + Storage	100 + 60	Hot Springs	197	61	252	0
10	Storage	20	Cheyenne	N/A	N/A	N/A	N/A
11	Storage	40	Gillette	N/A	N/A	N/A	N/A
12	Storage	60	Hot Springs	N/A	N/A	N/A	N/A

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4 ELCC Calculation for Black Hills Power's Renewable Resources

4.1 Overview

VERs such as wind and solar have fluctuating availability throughout the year and present variable capacity contribution towards system peak demand. The power system planners implement the Loss of Load Expectancy (LOLE) method or the rather novel Effective Load Carrying Capability (ELCC) method in order to determine the accreditable capacity provided by those resources to safeguard the grid's reliability.

LOLE method targets a reliability level of 0.1 days/year during which the capacity of resources are not sufficient to supply the demand. Certain generators have forced outage rates and resulting total generator availability levels cause insufficient generation when it is compared with hourly demand. LOLE is calculated based on the Loss of Load Probability (LOLP) that occurs primarily during the peak hours. However, evaluating a capacity contribution of resource during the peak hours results in an underestimation of the value provided by renewable resources. In order to understand the additional reliability contribution of variable energy resources to energy demand throughout the year, PG examined the impact on expected unserved energy value as well. The LOLE approach traditionally has been implemented to attain the planning reserve margin. Traditionally, a 0.1 day/year LOLE threshold for a power system has been targeted. When power systems consisted primarily of controllable thermal generation, the LOLE standard was measured and achieved by setting a reserve margin level and ensuring that load serving entities had sufficient capacity resources to meet the reserve margin during the peak hour. As the amount of variable energy resources increased on regional power systems, the industry began to examine metrics in addition to reserve margin to ensure the LOLE threshold is met, and for ways to recognize that variable energy resources contribute to system reliability beyond the expected generation level provided in just the peak hour. The ELCC method has been recognized as a sound analytic technique to better assess the reliability contribution of variable energy resources. The ELCC approach measures a new variable generator's contribution to overall resource adequacy by calculating the additional load that can be supplied at a certain reliability level. ELCC illustrates the new resource's load carrying capability for all hours in a year.

In order to determine the accreditable capacity for VERs, ELCC was calculated for BHP based on the LOLE metric. The LOLE metric is used to measure the effective capacity contribution of an individual variable energy resource addition by calculating the incremental impact on the same system. The Initial system's LOLE level represents the target reliability level to achieve after the variable resource addition. These calculations were completed for each of the Resource Portfolios with varied solar and wind resource additions, as well as paired solar and energy storage combinations as listed above in Table 3.

4.2 Methodology

LOLE was used as the metric to calculate the ELCC value for each Resource Portfolio. ELCC values represent the percentage of accreditable capacity that a given resource can reliably provide compared to its nameplate capacity.

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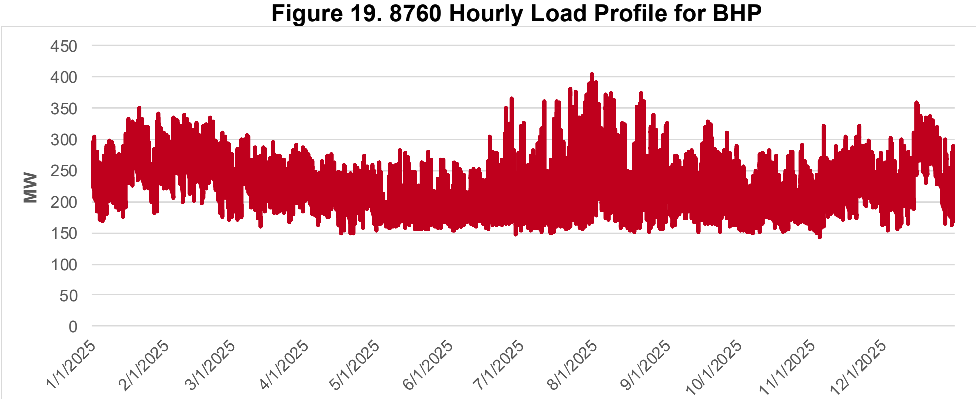
The LOLE calculation was performed hourly for the 2025 planning year. First, the reliability adequacy level of the BHP baseline system was calculated. This target reliability level is measured in hours of loss of load per year. Second, a variable energy resource (e.g. 50 MW wind) was added to the baseline system. Each incremental resource improves the baseline's LOLE value by providing a higher level of reliability. Then, PG calculated the additional load (e.g. 20 MW) that can be added to the system while achieving the same reliability level as the base system. Finally, this additional demand was divided by the nameplate capacity of the variable energy resource addition to calculate the ELCC of that resource. The ELCC value represents the quantity of 'perfect capacity' (with 100 percent availability) that could be replaced or avoided with wind, solar, storage, etc. while providing equivalent system reliability.

For example, if a 50 MW wind resource is added to the BHP system and it allows the system demand to be increased by 20 MW while achieving the same reliability level as the base system, the ELCC of that wind farm is equal to 20/50= 40%. As expected, adding larger amounts of renewable resources result in lower ELCC value provided by those resources. This approach is different than assessing the firm capacity of a renewable resource by just looking at its capacity contribution during the peak hour or a group of peak hours. The ELCC approach considers the value of the resource throughout the year and allows for a certain loss of load threshold.

PG received hourly data from BHP staff for its current and projected system demand and variable energy resource generation. BHP staff also provided thermal and renewable resource characteristics (e.g. unit capacity, generating unit forced outage rates). PG developed a spreadsheet-based tool to calculate the reliability of the BHP system by incorporating generator data, hourly system demand, and hourly capacity of named renewable resources and future renewable portfolios for the year 2025. The tool compares the hourly net load of the BHP system with 5,000 iterations of generation levels developed with Monte Carlo simulation. Collectively, those simulations reflect the forced outage rate of each generator. Those hours where the hourly net load exceeds a simulated generator availability level, are counted as loss of load hours.

Figure 19. 8760 Hourly Load Profile for BHP



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4.3 ELCC Results

PG calculated the hourly LOLE for the BHP base system for the year 2025. The BHP Base system's LOLE is 2.18 hours per year, which is less than the widely accepted 0.1 days/year (1 day in 10 years) reliability standard. BHP's base system for 2025 included ownership of 419 MW of thermal generation[5] and 159.5 MW of wind and solar resources.

Once a new variable energy portfolio is added to the system, the LOLE improves. The tool was then used to calculate the additional demand that the system can carry while still maintaining the 2.18 hours/year LOLE level attained by the base system. For example, with the addition of 100 MW wind at North Douglas, the LOLE changes to 0.77 hours/year, which represents an improvement due to new resource availability. The systemwide demand can be increased by 20.3 MW for every hour while the level of reliability reaches to 2.18 hours/year resulting in an ELCC value of 20.3% for the 100 MW wind located at North Douglas.

BHP requested that PG complete ELCC assessments for the solar, wind and solar plus energy storage portfolios shown in Table 3. In order to illustrate the impact of incremental capacity at the same location, PG calculated the ELCC for 50 MW, 100 MW, and 200 MW levels at each of the locations identified for the solar and wind portfolios.

Table 11 summarizes the ELCC value for all incremental portfolios including the solar plus energy storage portfolios. Energy storage resources in the hybrid portfolios are assumed to exclusively charge from the solar resource that they are paired with in order to be eligible for the investment tax credit. Thus, their charging and discharging schedule is optimized around the availability of solar.

Table 11. ELCC values for the BHP Portfolios

Portfolio	Type	Size (MW)	Location	Incremental Demand (MW)	ELCC (%)
1	Wind	50	Cheyenne	15	29%
2	Wind	100	S. Gillette	23	23%
3	Wind	200	N. Douglas	30	15%
4	Solar	50	Cheyenne	6	11%
5	Solar	100	Gillette	9	9%
6	Solar	200	Hot Springs	9	4%
7	Solar + Storage	100 + 40	Cheyenne	15	15%
8	Solar + Storage	100 + 20	Gillette	14	14%
9	Solar + Storage	100 + 60	Hot Springs	18	18%

[5] MDU's and COG's ownership of Wygen III is excluded from BHP's thermal generation total.

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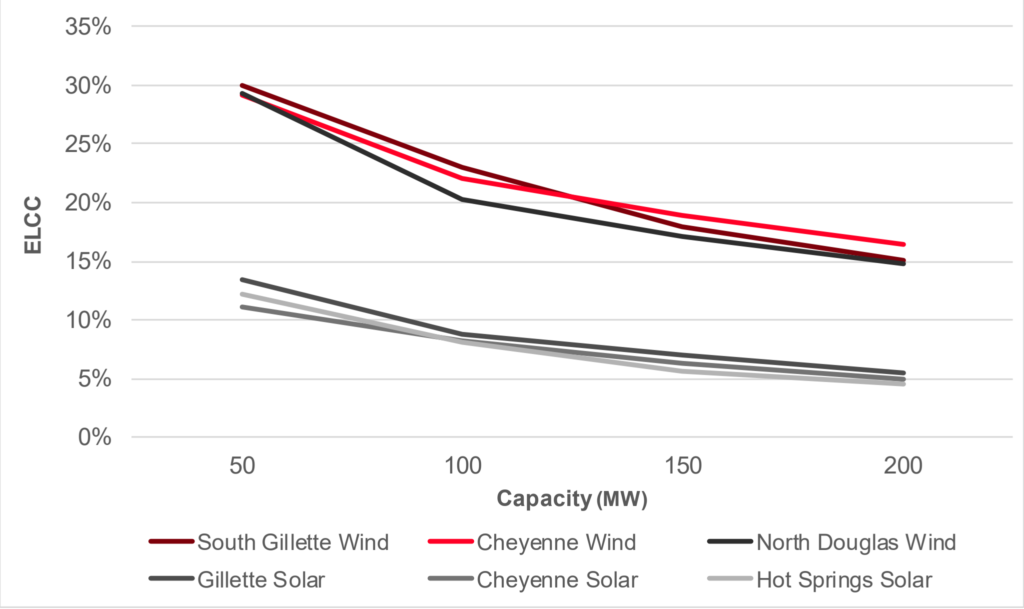
Pairing energy storage with solar resources resulted in an increase in the accreditable capacity for the solar plus BESS portfolios. Adding 20 MW, 40 MW, and 60 MW of energy storage increased the capacity value of the solar portfolios by 5 MW, 6 MW, and 9 MW, respectively. The energy storage charges from the solar resource during day-light hours reducing the availability of solar output during those hours but because of low and no solar irradiance periods the overall availability of the solar plus BESS resource is extended increasing the accreditable capacity of the resource

Figure 20 illustrates the calculated ELCC values for solar and wind resources. As the capacity of the resources increase, the accreditable capacity is reduced. The solar resources located at Gillette, Cheyenne, and Hot Springs have lower ELCC values than the wind resources at South Gillette, Cheyenne, and North Douglas. ELCC values for solar resources ranges from 4% to 13% while ELCC values for wind resources ranges from 15% to 30%. Future solar resources on average have a 26% capacity factor, which is much lower than the capacity factor for wind resources at 43%. This is the major reason for lower solar ELCC values. Low solar irradiance during the late afternoon periods also played a role in lower ELCC values for solar portfolios. Cheyenne Wind and Gillette Solar resulted in slightly higher ELCC values in their respective resource categories.

Figure 20. ELCC for Wind and Solar Portfolios



PG also calculated the ELCC value of stand-alone battery storage at four capacity levels, 20 MW, 40 MW, 60 MW and 100 MW. We determined the battery charge level in every hour to calculate the amount of capacity that a stand-alone battery storage facility can provide. This capacity ranges between 0 MW and the maximum capacity of the storage facility. Table 12 lists the estimated ELCC values. As the size of the capacity increases from 20 MW to 60 MW, the effective capacity contribution is expected to decrease from 80% to 54%.

Table 12. ELCC of Battery Storage

Type	Capacity (MW)	Incremental Demand (MW)	ELCC (%)
Storage	20	16	80%
Storage	40	27	67%
Storage	60	33	54%
Storage	100	49	49%

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5 Conclusion

In this study, PG examined Variable Energy Resource availability on the BHP system, considering both existing and planned new resources. PG estimated incremental amounts of Regulation Up and Regulation Down capacity that would be needed to reliably balance the BHP system considering twelve different potential portfolios of renewable energy and/or battery storage additions. PG also estimated likely changes in BHP operating costs for each of the resource portfolios, based on production cost modeling and changes in BHP system costs due to incremental regulation requirements. PG further estimated the potential need for BHP to procure additional flexible capacity resources for a subset of the resource portfolios, in cases where BHP's current generation portfolio is unable to meet flexible capacity needs driven by large ramps in VER generation output. Finally, PG estimated Effective Load Carrying Capability for wind and solar resource additions varying between 50 and 200 MW, at four different site locations including Cheyenne, WY, Douglas, WY, Gillette, WY and Hot Springs, SD. Table 13 below summarizes quantitative results from each of those sets of analyses.

Table 13. VER Integration Summary Results

Portfolio	Type	Size (MW)	Location	98% CPS2: Incremental Regulation Up (MW)	98% CPS2: Incremental Regulation Down (MW)	Regulation Generation Cost ($/MWh)	Regulation WAPA Tariff ($/kW/Mo)	Flexible Resource Need (MW)	ELCC (%)
Existing System				55	55			239	
1	Wind	50	Cheyenne	24	0	$10.17	$0.303	0	29%
2	Wind	100	S. Gillette	26	22	$6.56	$0.303	0	23%
3	Wind	200	N. Douglas	50	40	$11.12	$0.303	86	15%
4	Solar	50	Cheyenne	7	1	$5.38	$0.205	0	11%
5	Solar	100	Gillette	10	1	$4.63	$0.205	16	9%
6	Solar	200	Hot Springs	11	1	$1.57	$0.205	118	4%
7	Solar + Storage	100 + 40	Cheyenne	0	1	$0.02	$0.205	0	15%
8	Solar + Storage	100 + 20	Gillette	0	1	$0.03	$0.205	0	14%
9	Solar + Storage	100 + 60	Hot Springs	0	1	$0.02	$0.205	0	18%
10	Storage	20	Cheyenne	0	1	N/A		N/A	80%
11	Storage	40	Gillette	0	1	N/A		N/A	67%
12	Storage	60	Hot Springs	0	1	N/A		N/A	54%

As shown in Table 13, Regulation Up requirements for wind resources vary from 24 to 50 MW depending on the size and location of a wind resource. Regulation Down requirements for wind resource vary from zero to 40 MW, and regulation costs vary from $6.56/MWh to $11.12/MWh when provided by BHP generation. Regulation Up and Regulation Down requirements for solar resource additions are much lower, ranging from 7 to 11 MW for Regulation Up, and 1 MW for

Regulation Down. For solar resources, regulation costs vary from $1.57/MWh to $5.38/MWh when provided by BHP generation. Pairing battery storage technology with solar resources lowers the regulation cost and requirements significantly, as the battery facility is able to cover incremental Regulation Up requirements, and Regulation Down requirements remain at 1 MW.

Regulation costs are lower when procured through WAPA's OATT, in which case regulation costs are $0.303/kW/Month for wind resources and $0.205/kW/Month for solar resources. At a 40% annual average wind capacity factor, the WAPA regulation cost is equivalent to $1.04/MWh for wind resources, and at a 25% annual average capacity factor for solar, it would be equivalent to $1.12/MWh for solar resources.

Three of the Resource Portfolios outlined in Table 13 have flexible capacity requirements, with estimated capacity needs of 86 MW for Resource Portfolio 3, 16 MW for Resource Portfolio 5, and 118 MW for Resource Portfolio 6. Costs associated with procuring that additional flexible capacity will be reflected in BHP's IRP, based on a Busbar cost study that is currently being completed by Black & Veatch.

ELCC values for the renewable technologies in each Resource Portfolio vary from 29 percent down to 4 percent, with ELCC declining as the size of a project addition increases. ELCC values for wind resources are considerably higher than for solar resources, due primarily to a higher capacity factor. For battery resources, ELCC values are estimated at 80 percent for a 20 MW installation, declining to 67 percent for a 40 MW installation, 54% for a 60 MW installation, and 49% for a 100 MW installation.

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G. BALANCING AUTHORITY FEASIBILITY STUDY

This study examined the feasibility of Cheyenne Light and Black Hills Power becoming a Balancing Authority (BA), and identified the roles, responsibilities, and required staffing to satisfy BA certification, operation, and compliance requirements. The study examined the cost differences among becoming a BA, staying with WAPA, or switching to the PacifiCorp East BA.

The study found that both utilities are well situated to become a BA and separate from WAPA. This finding, however, is mitigated by a somewhat greater cost. Becoming a BA would cost between $5.77 and $10.21 million annually. Remaining with WAPA as BA would cost between $3.54 and $5.28 million annually. Changing to PacifiCorp as its BA would cost between $3.10 and $3.21 million annually.

Balancing Authority Feasibility Study

Black Hills Power

April 23, 2020

Prepared by:

NAES Corporation

Gridforce

EnergyWest

Sound Grid Partners

NAES

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Introduction

On September 5, 2019 a master consulting agreement was executed between Black Hills Power and NAES Corporation to provide a study that outlines the feasibility and gaps associated with alternative Balancing Authority (BA) service scenarios. The executive report and overall summary analysis are provided below.

Executive Summary

Establishing and maintaining a Balancing Authority (BA) consists of three primary components; certification, operations, and compliance. Black Hills Energy (Black Hills) in taking on the Balancing Authority function must first show NERC and WECC its preparedness for complying with all applicable NERC Reliability Standards, including FERC approved regional standards and requirements. Black Hills will provide evidence of its program, including systems, tools and processes for meeting compliance obligations during a Balancing Authority Certification Review of each applicable requirement. Once satisfactory evidence of process and/or tools to support compliance has been presented to the satisfaction of the certification review team, a recommendation of certification is presented to NERC. NERC documents approval of its certification, generally through a notification by letter, and Black Hills BA function status is added to its NERC registration based on the start date for the Balancing Authority operations. Once certified, Black Hills must start Balancing Authority functions within twelve months or go through the certification process again. There is much coordination required with neighboring Balancing Authorities and Transmission Operators to ensure that proper modeling is completed in systems and delineate BA boundaries with appropriate metering of tie lines. The new BA entity must then operate the Balancing Authority within the standards set by NERC and the regional entity as well as provide evidence of its compliance with those standards monthly, annually, and on a three-year audit cycle.

The following analysis will identify for Black Hills Energy, the roles and responsibilities as well as any additional staffing needs required to satisfy Balancing Authority certification, operation, and compliance requirements. Additionally, we have provided a cost comparison analysis of the status quo (remaining a part of the WAPA BA), Black Hills standing up their own BA, or moving to having PacifiCorp provide BA services for Black Hills as shown in Tables 25 & 26 below.

The timeline to establish a balancing authority is 9-12 months and the estimated cost of implementation which includes recommended headcount additions is $730,045, with an ongoing estimated annual support cost of $530,000.

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Balancing Authority Operating Cost Comparison--Low Cost Scenario			
	WAPA as BA	BHE as BA	PACE as BA
Scheduling, System Control, and Dispatch Service	$ 316,416	incl below	$ 682,021
Reactive Supply, Voltage Control from Gen. or Other	$ 213,551	$ 213,551	$ 213,551
Regulation	$ 2,008,546	incl in imbal	$ 1,990,735
Frequency Response Service	incl in reg	$ 72,000	incl in reg
Imbalance/Inadv. Inter. (96% imbalance coverage)	$ 406,248	$ 3,504,114	$ (514,386)
Reserves	$ 597,000	$ 597,000	$ 729,000
BA Desk Staffing	-	$ 553,000	-
Compliance/Training Staffing	-	$ 308,000	-
IT Staffing/Systems	-	$ 201,920	-
Reporting/Admin/Other	-	$ 320,600	-
Totals	$ 3,541,761	$ 5,770,185	$ 3,100,921

Table 1: BA Services itemized annual cost comparison, BHE Low Cost Scenario

Balancing Authority Operating Cost Comparison--High Cost Scenario			
	WAPA as BA	BHE as BA	PACE as BA
Scheduling, System Control, and Dispatch Service	$ 316,416	incl below	$ 682,021
Reactive Supply, Voltage Control from Gen. or Other	$ 213,551	$ 213,551	$ 213,551
Regulation	$ 2,008,546	incl in imbal	$ 2,101,199
Frequency Response Service	incl in reg	$ 600,000	incl in reg
Imbalance/Inadv. Inter. (99% imbalance coverage)	$ 406,248	$ 5,325,368	$ (514,386)
Reserves	$ 2,334,300	$ 2,334,300	$ 729,000
BA Desk Staffing	-	$ 903,000	-
Compliance/Training Staffing	-	$ 308,000	-
IT Staffing/Systems	-	$ 201,920	-
Reporting/Admin/Other	-	$ 320,600	-
Totals	$ 5,279,061	$ 10,206,739	$ 3,211,385

Table 2: BA Services itemized annual cost comparison, BHE High Cost Scenario

Black Hills Energy is well positioned to take on the Balancing Authority function within WECC. The organization is well staffed and with its current NERC functional registrations (TOP, TO, TSP, TP, RP, DP, PA / PC), the Balancing Authority function is the next logical step. The BA certification preparation will require focused staff to complete required systems updates, develop procedures, complete RSAWs, and perform Balancing Authority training.

NERC Compliance

The standards that are required by NERC for Balancing Authority (BA) registrants only and a description of such are listed below. There are other standards required for BA and other registrations, which have been previously implemented by Black Hills. Those standards were not considered in this analysis as it is assumed that Black Hills is already maintaining compliance with those standards.

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NERC has a document titled, "Balancing *Authority Area Footprint Change Tasks"*. It outlines the necessary tasks to make changes to a BA. It is included in Attachment A. The process below assumes Black Hills decides to move forward as its own BA.

Balancing Authority Certification Process

1. The Certification Application
    a. Black Hills will be required to submit a Balancing Authority Certification Application to WECC. The Application will be an overview of the proposed Balancing Authority footprint, generation capacity, peak load, transmission facilities, etc.
    b. Once the certification application is accepted, the certification process must be completed within nine months of the Regional Entity accepting the application for certification unless all involved parties agree, and NERC approves.
    We estimate that the time to complete certification application is 1-2 hours at a cost of $153.
2. Certification Review Preparation
    a. Appropriate procedures should be developed to identify "how" Black Hills will comply with the NERC Reliability Standards applicable to the BA.
    b. Internal Controls for managing the newly developed processes and procedures should be identified with an implementation plan that accounts for any activities that need to occur in advance of the first day of operations.
    c. Black Hills should complete all Reliability Standards Audit Worksheets (RSAWs) associated with all NERC Standards applicable to a Balancing Authority to identify sources of evidence and where internal controls should be applied to support the BA function.
    d. We estimate the time to complete the certification review preparations to be 8-16 months (1280-2560 man-hours) at a cost of $98,154-$196,308 for labor.
3. Certification Review Team Site Visit
    a. Black Hills will host a Certification Team composed of appropriate representatives, generally WECC, NERC, a Reliability Coordinator and other appropriate functional entities. The certification audit will take 2-3 days and Black Hills will need to make compliance, operations, and management personnel available for the entirety of the onsite audit. Estimated cost for Black Hills personnel to support the on-site audit is $7,163.
    b. Black Hills must demonstrate to the Certification Team, how it will meet each of the BA requirements with key focus during the onsite portion being readily accessible procedures, functioning systems and trained system operators.
    c. Certification Team members will prepare a report following the onsite indicating any issues that must be resolved prior to BA certification being granted, commonly referred to as "Bucket 2" items.

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Northwest Power Pool (NWPP) Participation

1. Black Hills will apply to become a member of the NWPP.
    a. All Balancing Authorities within the NWPP region must become members of the Operating Committee and Reserve Sharing Group and execute required agreements with payment commitments for participation and ongoing settlement requirements for assistance. The ongoing administration costs to NWPP is approximately $100,000/year. The time commitment to participate in committee meetings, checkouts, and invoicing is estimated to be 140 hours/year with an estimated labor cost of $9,690. /year plus associated travel costs.
    b. Black Hills will need to complete all requirements of NWPP to become a member, which will include modifications to the Energy Management System (as described below, data exchange, identification of the Most Severe Single Contingency (MSSC), and creation of templates based on the selected delivery point for Contingency Reserves

Compliance Reporting Requirements

Compliance Reporting is a regular task that must be managed within the Balancing Authority. Daily submittals will require some level of automation to communicate data in the Electric Industry Data Exchange (EIDE) format. This work is estimated to require 80 hours for an application developer at a cost of $8,365 The daily, monthly, quarterly, and annual submittals will require 992 hours/year at an approximate cost of $64,915/year. The every 3-year audit preparation will require 200 hours at an approximate cost of $15,337.

1. Daily BA compliance submittals
    a. Energy Information Administration (EIA-930) reporting, delivered in an hourly format
        i. EIDE file format for automation should be considered
    b. Planning Submittals to Reliability Coordinator
        i. Forecasted Load/Generation
        ii. Forecasted Reserves
2. Monthly BA compliance submittals
    a. CPS 1 reporting
    b. BAAL Limit Exceedance reporting is voluntary, but all BAs currently participate
    c. Inadvertent Energy based on validation and finalization of WIT data
3. Quarterly BA compliance submittals
    a. Primary Frequency Response NWPP (if a member of the Western Frequency Response Sharing Group (WFRSG)
4. Annual BA compliance submittals
    a. FERC-714 submittal
    b. Frequency Response Reporting; a quarterly assessment is recommended to ensure that any needed adjustments are identified early in the compliance measurement period

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   c. WECC Self-Certifications as published in the WECC compliance and reporting applications, currently CDMS
   d. WECC Load and Resources Reporting
5. 3-Year NERC audit cycle
   a. Risk Assessment
   b. Evidence Collection
   c. RSAW preparation
   d. Onsite audit activities

Required Standards

The following Standards in Table 1 below, are required by NERC for Balancing Authority (BA) registrants only:

BAL-001-2 R1	The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly.
BAL-001-2 R2	Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.
BAL-002-3 R1.	The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:
BAL-002-3 R1.1	within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: • zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event, or, • its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing

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	Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.
BAL-002-3 R1.2	Document all Reportable Balancing Contingency Events using CR Form 1.
BAL-002-3 R1.3	Deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity
BAL-002-3 R1.3.1	is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that: • is experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and • is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and • has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and • has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time or,
BAL-002-3 R1.3.2	the Responsible Entity experiences: • multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or • multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

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BAL-002-3 R2	Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.
BAL-002-3 R3	Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period.
BAL-002-WECC-2a R1	Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is:
BAL-002-WECC-2a R1	The greater of either: • The amount of Contingency Reserve equal to the loss of the most severe single contingency; • The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.
BAL-002-WECC-2a R1.1	The greater of either: • The amount of Contingency Reserve equal to the loss of the most severe single contingency; • The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.
BAL-002-WECC-2a R1.2	Comprised of any combination of the reserve types specified below: • Operating Reserve – Spinning • Operating Reserve - Supplemental • Interchange Transactions designated by the Source Balancing Authority as Operating Reserve – Supplemental

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	• Reserve held by other entities by agreement that is deliverable on Firm Transmission Service • A resource, other than generation or load, that can provide energy or reduce energy consumption • Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement. • All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.
BAL-002-WECC-2a R1.3	Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).
BAL-002-WECC-2a R1.4	An amount of capacity from a resource that is deployable within ten minutes.
BAL-002-WECC-2a R2	Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning that meets both of the following reserve characteristics.
BAL-002-WECC-2a R2.1	Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;
BAL-002-WECC-2a R2.2	Reserve that is capable of fully responding within ten minutes.
BAL-002-WECC-2a R3	Each Sink Balancing Authority and each sink Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except

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	within the first sixty minutes following an event requiring the activation of Contingency Reserve.
BAL-002-WECC-2a R4	Each Source Balancing Authority and each source Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source Balancing Authority or source Reserve Sharing Group.
BAL-003-1.1 R1	Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.
BAL-003-1.1 R2	Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO.
BAL-003-1.1 R3	Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is:
BAL-003-1.1 R3.1	Less than zero at all times, and

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BAL-003-1.1 R3.2	Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.
BAL-003-1.1 R4	Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either:
BAL-004-WECC-3 R1	Each Balancing Authority shall operate its system such that, following the conclusion of each month, the month-end absolute value of its On-Peak and Off-Peak, Accumulated Primary Inadvertent Interchange (PII accum), as calculated by the WECC Interchange Tool (WIT) or its successor electronic confirmation tool, are each individually less than or equal to:
BAL-004-WECC-3 R1.1	For load-serving Balancing Authorities, 150% of the previous calendar year's integrated hourly Peak Demand,
BAL-004-WECC-3 R1.2	For generation-only Balancing Authorities, 150% of the previous calendar year's integrated hourly peak generation.
BAL-004-WECC-3 R2	Each Balancing Authority shall, upon discovery of an error in the calculation of PII hourly, recalculate within 90 days, the value of PII hourly and adjust the PII accum from the time of the error.
BAL-004-WECC-3 R3	Each Balancing Authority shall keep its Automatic Time Error Correction (ATEC) in service, with an allowable exception period of less than or equal to an accumulated 24 hours per calendar quarter for ATEC to be out of service.
BAL-004-WECC-3 R4	Each Balancing Authority shall compute each of the following using the WECC Interchange Tool (WIT) or its successor electronic confirmation tool, no later than 50 minutes after each hour,
BAL-004-WECC-3 R4.1	PII hourly,

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BAL-004-WECC-3 R4.2	PII accum,
BAL-004-WECC-3 R4.3	Automatic Time Error Correction term (IATEC).
BAL-004-WECC-3 R5	Each Balancing Authority shall be able to change its Automatic Generation Control operating mode between Flat Frequency (for blackout restoration); Flat Tie Line (for loss of frequency telemetry); Tie Line Bias; and Tie Line Bias plus Time Error Control (used in ATEC mode), to correspond to current operating conditions.
BAL-004-WECC-3 R6	Each Balancing Authority shall recalculate the PII hourly and PII accum for the On-Peak and Off-Peak periods whenever adjustments are made to hourly Inadvertent Interchange or TE.
BAL-004-WECC-3 R7	Each Balancing Authority shall make the same adjustment to the PII accum as it did for any month-end meter reading adjustments to Inadvertent Interchange.
BAL-004-WECC-3 R8	Each Balancing Authority shall payback Inadvertent Interchange using ATEC rather than bilateral and unilateral payback.
BAL-005-1 R1	The Balancing Authority shall use a design scan rate of no more than six seconds in acquiring data necessary to calculate Reporting ACE.
BAL-005-1 R2	A Balancing Authority that is unable to calculate Reporting ACE for more than 30-consecutive minutes shall notify its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE.
BAL-005-1 R3	Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE: 3.1. that is available a minimum of 99.95% for each calendar year; and, 3.2. with a minimum accuracy of 0.001 Hz.
BAL-005-1 R3.1	that is available a minimum of 99.95% for each calendar year; and,
BAL-005-1 R3.2	with a minimum accuracy of 0.001 Hz.

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BAL-005-1 R4	The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data.
BAL-005-1 R5	Each Balancing Authority's system used to calculate Reporting ACE shall be available a minimum of 99.5% of each calendar year.
BAL-005-1 R6	Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of Reporting ACE for each Balancing Authority Area
BAL-005-1 R7	Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with:
BAL-005-1 R7.1	a common source to provide information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE; and,
BAL-005-1 R7.2	a time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors.
COM-001-3 R5	Each Balancing Authority shall have Interpersonal Communication capability with the following entities (unless the Balancing Authority detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply):
COM-001-3 R5.1	Its Reliability Coordinator.
COM-001-3 R5.2	Each Transmission Operator that operates Facilities within its Balancing Authority Area.
COM-001-3 R5.3	Each Distribution Provider within its Balancing Authority Area.
COM-001-3 R5.4	Each Generator Operator that operates Facilities within its Balancing Authority Area.

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COM-001-3 R5.5	Each Adjacent Balancing Authority.
COM-001-3 R6	Each Balancing Authority shall designate an Alternative Interpersonal Communication capability with the following entities:
COM-001-3 R6.1	Its Reliability Coordinator.
COM-001-3 R6.2	Each Transmission Operator that operates Facilities within its Balancing Authority Area.
COM-001-3 R6.3	Each Adjacent Balancing Authority.
EOP-011-1 R2	Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [See Standard for additional information.]
EOP-011-1 R2.1	Roles and responsibilities for activating the Operating Plan(s);
EOP-011-1 R2.2	Processes to prepare for and mitigate Emergencies including:
EOP-011-1 R2.2.1	Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;
EOP-011-1 R2.2.2	Requesting an Energy Emergency Alert, per Attachment 1;
EOP-011-1 R2.2.3	Managing generating resources in its Balancing Authority Area to address:
EOP-011-1 R2.2.3.1	Managing generating resources in its Balancing Authority Area to address:
EOP-011-1 R2.2.3.2	fuel supply and inventory concerns;
EOP-011-1 R2.2.3.3	fuel switching capabilities; and
EOP-011-1 R2.2.3.4	environmental constraints.

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EOP-011-1 R2.2.4	Public appeals for voluntary Load reductions;
EOP-011-1 R2.2.5	Requests to government agencies to implement their programs to achieve necessary energy reductions;
EOP-011-1 R2.2.6	Reduction of internal utility energy use;
EOP-011-1 R2.2.7	Use of Interruptible Load, curtailable Load and demand response;
EOP-011-1 R2.2.8	Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and
EOP-011-1 R2.2.9	Reliability impacts of extreme weather conditions.
INT-004-3.1 R3	Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures.
INT-006-4 R1	Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. [Please see the standard for more information]
INT-006-4 R1.1	Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.
INT-006-4 R1.2	Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.
INT-006-4 R3	The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or

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	deny it prior to the expiration of the time period defined in Attachment 1, Column B. [Please see the standard for more information]
INT-006-4 R3.1	If a Balancing Authority denies a Reliability Adjustment Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial.
INT-006-4 R4	Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: • It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition. • It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition. • It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.
INT-006-4 R5	For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: [Please see the standard for more information]
INT-006-4 R5.1	The Source Balancing Authority,
INT-006-4 R5.2	Each Intermediate Balancing Authority,

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INT-006-4 R5.3	Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,
INT-006-4 R5.4	Each Transmission Service Provider included in the Arranged Interchange, and
INT-006-4 R5.5	Each Purchasing Selling Entity included in the Arranged Interchange.
INT-009-2.1 R1	Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is:
INT-009-2.1 R1.1	Identical in magnitude to that of the Adjacent Balancing Authority, and
INT-009-2.1 R1.2	Opposite in sign or direction to that of the Adjacent Balancing Authority.
INT-009-2.1 R2	The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NIA) term of their respective control ACE (or alternate control process).
INT-009-2.1 R3	Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.
INT-010-2.1 R1	The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not

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	exceed 60 minutes from the time of the resource loss, no RFI is required.
INT-010-2.1 R2	Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons.
INT-010-2.1 R3	Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange Schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons.
IRO-006-5 R1	Each Reliability Coordinator and Balancing Authority that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any Reliability Coordinator, Balancing Authority, or Transmission Operator in another Interconnection to curtail an Interchange Transaction that crosses an Interconnection boundary shall comply with the request, unless it provides a reliability reason to the requestor why it cannot comply with the request.
IRO-006-WECC-3 R2	Each Balancing Authority receiving an approved request for unscheduled flow transmission relief on a Qualified Path per Requirement R1, shall perform any of the following actions to meet that request: • Approve curtailment requests to the schedules as submitted • Implement alternative actions
MOD-004-1 R10	The Load-Serving Entity or Balancing Authority shall request to import energy over firm Transfer Capability set aside as CBM only when experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. [Time Horizon: Same-day Operations]

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MOD-004-1 R11	When reviewing an Arranged Interchange using CBM, all Balancing Authorities and Transmission Service Providers shall waive, within the bounds of reliable operation, any Real-time timing and ramping requirements. [Time Horizon: Same-day Operations]
PER-003-2 R3	Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates
PER-003-2 R3.1	Areas of Competency
PER-003-2 R3.1.1	Resources and demand balancing
PER-003-2 R3.1.2	Emergency preparedness and operations
PER-003-2 R3.1.3	System operations
PER-003-2 R3.1.4	Interchange scheduling and coordination
PER-003-2 R3.2	Certificates • Reliability Operator • Balancing, Interchange and Transmission Operator • Balancing and Interchange Operator
TOP-001-4 R2	Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
TOP-001-4 R11	Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
TOP-001-4 R17	Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

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TOP-001-4 R22	Each Balancing Authority shall have data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations.
TOP-001-4 R23	Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions.
TOP-001-4 R24	Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality.
TOP-002-4 R4	Each Balancing Authority shall have an Operating Plan(s) for the next day that addresses:
TOP-002-4 R4.1	Expected generation resource commitment and dispatch
TOP-002-4 R4.2	Interchange scheduling
TOP-002-4 R4.3	Demand patterns
TOP-002-4 R4.4	Capacity and energy reserve requirements, including deliverability capability
TOP-002-4 R5	Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s).
TOP-002-4 R7	Each Balancing Authority shall provide its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator.
TOP-003-3 R2	Each Balancing Authority shall maintain a documented specification for the data necessary for

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	it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: [See standard for additional information.]
TOP-003-3 R2.1	A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.
TOP-003-3 R2.2	Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
TOP-003-3 R2.3	A periodicity for providing data.
TOP-003-3 R2.4	The deadline by which the respondent is to provide the indicated data.
TOP-003-3 R4	Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring.
TOP-010-1(i) R2	Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include:
TOP-010-1(i) R2.1	Criteria for evaluating the quality of Real-time data;
TOP-010-1(i) R2.2	Provisions to indicate the quality of Real-time data to the System Operator; and
TOP-010-1(i) R2.3	Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions.

Table 3: NERC Standards

Historical Violations and Fines Paid by Balancing Authorities

In an effort to summarize the risk of being a registered entity, Table 2 below includes a summary from NERC of violations and fines that were paid by Entities between 2011 and 2019. The violations shown included BAL standard violations, among other violations.

Date	Regulatory Filing ID	Total Penalty ($)
9/8/2017	NP-17-31-000	$500,000
1/28/2016	NP-16-8-000	No Penalty
9/30/2013	NP13-52-000	$5000
7/31/2012	NP12-38-000	$72,000
4/30/2012	NP12-24-000	$12,000
1/31/2012	NP12-11-000	$135,000
12/30/2011	NP12-9-000	$60,000
9/30/2011	NP11-269-000	$225,000
9/30/2011	NP11-268-000	$384,000
7/28/2011	NP11-233-000	$70,000
5/26/2011	NP11-198-000	$17,860
5/26/2011	NP11-188-000	$16,860
4/29/2011	NP11-180-000	$71,500
4/29/2011	NP11-176-000	$80,000
2/28/2011	NP11-132-000	$46,000
2/23/2011	NP11-128-000	$450,000
2/23/2011	NP11-105-000	$45,000

Table 4: NERC Violations

Staffing to Support BA Operations

If Black Hills decides to setup their own BA, NAES is recommending that Black Hills add three additional personnel to their current staffing for a total estimate cost of $530,000/year broken down as follows:

1. Manager of the BA Real-Time desk @ $145,000/year salary plus associated burden
2. BA Compliance Coordinator @ $110,000/year salary plus associated burden
3. BA Training Coordinator @ $110,000/year salary plus associated burden

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4. In Gridforce's experience, the following personnel are not required, however, Black Hills should internally analyze whether these personnel should be added to their current staff:
    a. 1. EMS Engineer
    b. 1 Inadvertent Energy Analyst
    c. Up to 5 NERC certified System Operators

Additional details regarding the necessary additional activities of Black Hills personnel to support BA operations are outlined in the below:

1. Balancing Authority Certification
    a. 1 FTE for six months to complete RSAWs for certification audit
    b. 1 FTE for six months to develop required balancing authority procedures
    c. 1 FTE for four months to develop and deliver balancing authority training
2. Balancing Authority Operations Control Center Desk
    a. 5 NERC BA/Interchange certified operators to support rotating shift operations
    b. 1 Manager to support real-time BA desk, that is responsible for the BA operators. The BA operation is a new function with numerous training, compliance and reporting responsibilities so there should be someone in management responsible for these activities.
    c. 1 Trainer to support NERC PER-005 training requirements
3. NWPP participation
    a. Participate in quarterly OC meetings; may be the identified manager function
    b. Participate in quarterly RSG meetings; may be the identified manager function
4. After the fact (ATF) Inadvertent Energy Accounting
    a. 1 FTE to manage after the fact checkouts and reporting to WECC/NERC and participate in Interchange Scheduling and After-the-fact Accounting (ISAS) quarterly meetings.

System Changes to Support BA Operations

OSI Monarch Energy Management System Modifications

Black Hills current Energy Management System (EMS) has the capacity, with appropriate modifications, to handle the necessary real time calculations to facilitate Black Hills becoming its own BA. These required modifications are outlined below and the estimated cost to make these changes is 380 hours at $32,276 assuming Black Hills EMS support personnel can accomplish this work without vendor assistance.

1. Within its existing EMS, Black Hills will establish an Area Control Error (ACE) calculation in accordance with the NERC definition of Reporting ACE, including components identified below:
    a. Automatic Time Error Control (ATEC)
    b. Net Actual Interchange using Adjacent BA Tie Lines
    c. Net Scheduled Interchange
    d. Actual Frequency
    e. Scheduled Frequency
    f. Frequency Bias Setting (to be coordinated with NERC for newly created BA)

2. Parameters that are needed for calculating Black Hills performance as a BA under CPS 1 and BAAL must be added to the system such as the Western Interconnection frequency bias setting and NERC established epsilon values.
3. Black Hills will integrate with the WIT Application to collect hourly and accumulated Primary Inadvertent Interchange (PII) values that will be used in developing the ATEC parameter of the ACE equation.
4. Black Hills will establish Northwest Power Pool Reserve Sharing ICCP points to support required data exchange and operator displays that will be used to show the real-time Contingency Reserves status of the NWPP RSG Participants and the Black Hills BA.
5. Black Hills will establish the planning and real-time MSSC logic to support identification of Reportable Balancing Contingency Events (RBCE).
6. Black Hills will establish appropriate alarms around key reliability and performance indicators for the BA based on Black Hills alarm methodology and a heartbeat to monitor alarming is functioning.
7. Automatic Generation Control (AGC) with appropriate Black Hills resources will be established and modeled.
8. If relying on dynamically transferred resources in a remote BA, Black Hills will model either a Pseudo-Tie or Dynamic Schedule for each transfer.
9. Identify EMS data points that will be added to the Black Hills historian and any trends that will be used to monitor key performance indicators.

Inadvertent Energy Accounting System

Black Hills will be required to make the below changes to its energy accounting system to enable the ability to calculate hourly, daily, and monthly accumulated NERC and primary inadvertent interchange. The estimated effort for this work will include technical resources as well as compliance and testing resources. The cost for this effort is estimated to be $31,370 if all work can be performed with internal resources. The ongoing management of balancing authority inadvertent energy checkouts will require approximately 180 hours/year at an estimated cost of $10,666/year.

10. Hourly and accumulated NERC inadvertent (NSI vs. NAI) and hourly primary inadvertent interchange (PII) calculations (Inadvertent) will be established in the Black Hills energy accounting system.
11. The energy accounting system must maintain hourly and accumulated On peak and Off peak NERC and PII inadvertent energy calculations.
12. Monthly Inadvertent calculations will be established in the Black Hills energy accounting system.
13. Ensure that there is a process for updating the Western Interchange Tool (WIT) with data from the Black Hills Energy Accounting System to support NERC reporting of accumulated Inadvertent.

Tagging System

14. Based on existing use of the OATI product Black Hills will need to add OATI WebTrans for tagging and scheduling and Tag Approval Authority to support the

BA function. This is likely an additional subscription to be added to current services from OATI.

Reliability Coordinator and TOP-003 Data Request

Black Hills must develop the below forecast and planning processes. This will require effort from both compliance and EMS support personnel. The initial effort will require 200 hours at an approximate cost of $16,173. Ongoing costs to support changes in requirements and data is approximately $1,966/year.

15. Black Hills will establish a forecast and planning process for exchanging information with the Reliability Coordinator to provide forecasted load, generation capacity, limits and reserves for example as documented in the posted version of the RC IRO-010 data request. ICCP data links will be modeled based on the real-time data exchange obligations in the posted version of the RC IRO-10 data request.
16. Black Hills will establish a forecast and planning process for exchanging information with other Transmission Operators and Balancing Authorities based on published TOP-003 data requests. ICCP data links will be modeled based on the real-time data exchange obligations established in TOP-003 data request.

Metering Requirements

Black Hills Energy should assume it will be required to install all Interchange Metering as the current metering is owned by WAPA.

a. Revenue quality metering is required at a cost of $3,000/meter.
b. The time to install and test the new metering would be 32 -hours of labor per meter.
c. Total cost to install new meters across the Black Hills system is estimated to be approximately $45,000.

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Operations, Tariff Development and Discussion of overall Cost, Rate Impacts and Comparison to Current BA Providers

Overview

BHE is considering leaving WAPA as its current BA service provider. In summarizing the economic and operational feasibility of BHE becoming their own Balancing Area Authority (BA), or considering PacifiCorp East as alternate BA provider, we have organized the remainder of this Feasibility Study according to the following:

- Discussion of Status Quo
  - Overview and WAPA Invoice Summary
  - Load Description
  - Resources and Purchase Power Agreements
  - Resource Economics
  - Model Description and Assumptions
  - Optimal Dispatch Results
- List of Balancing Standards and Analysis Plan
- Analysis of Individual BA Functions and Alternatives
  - Scheduling, System Control and Dispatch Service
  - Reactive Supply and Voltage Control
  - Frequency Response
  - Regulation
    - Ace Diversity Interchange
    - BAL004
  - Energy and Generator Imbalance
  - Reserves
- Implementation Timeline
- Cost Comparison: WAPA, BHE, PACE
- Summary of Findings

Discussion of Status Quo

WAPA Invoice Summary

Black Hills currently operates in two load centers (BHE and Cheyenne Light Fuel & Power, or CLFP), and uses its fleet of resources and Purchase Power Agreements (PPAs) to meet the vast majority of its load. BHE operates a sub-Balancing Area within the WAPA WACM Balancing Area. BHE does some degree of matching resource to load via BHE-hosted energy management and automatic generation control (AGC). BHE is in the process of outfitting all of its resources with AGC. BHE does not currently have compliance obligations to WECC/NERC for its sub-BA. Rather, BHE procures BA compliant services from WAPA who are in turn responsible to WECC/NERC for compliance.

BHE also procures transmission services (both Network Integration Service and Point-to-Point) from both WAPA and Black Hills Basin Electric. In connection with services

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provided by WAPA, WAPA bills for transmission ancillary services and BA services under two separate sets of invoices. Most charges are captured under WAPA invoices for BHE, which includes (among other things) energy (load) imbalance charges and generator imbalance charges for Silver Sage wind farm. A smaller WAPA invoice includes charges for generator imbalance for Happy Jack wind, regulation associated with Happy Jack, Reactive Supply and Voltage Control, and transmission associated with NITS. Table 3 below is a summary of the combination of both invoice sets, broken out between non-commodity type products (Services) and commodity type products (Energy and Transmission).

	Summary of WAPA Invoices		
	One year totals	Services	Energy/Trans
ANCILLARY SERVICE - REGULATION (WACM)	$ 2,020,925	$ 2,020,925	
ANCILLARY SERVICE - SCHED/DISP (WACM)	$ 316,416	$ 316,416	
ANCILLARY SERVICE - REACTIVE SUPPLY	$ 213,553	$ 213,553	
NETWORK TRANSMISSION	$ 11,536,510		$ 11,536,510
ECONOMY ENERGY	$ 1,139,317		$ 1,139,317
NONFIRM TRANSMISSION (ASSOC W/ ECON ENERGY S.	$ 428,126		$ 428,126
ECONOMY ENERGY - GENERATOR IMBALANCE	$ 422,133		$ 422,133
NONFIRM TRANSMISSION (SLC)	$ 121,858		$ 121,858
SPINNING RESERVES	$ 93,507		$ 93,507
NONFIRM TRANSMISSION (LAP)	$ 40,757		$ 40,757
RMRG RESERVE ACTIVATION	$ 19,586		$ 19,586
ECONOMY ENERGY - LOSSES (LAP)	$ 11,184		$ 11,184
PURCHASE POWER - ECONOMY ENERGY	$ (151,160)		$ (151,160)
PURCHASE POWER - ENERGY IMBALANCE	$ (296,417)		$ (296,417)
Total	$ 15,702,742	$ 2,337,341	$ 13,365,401

Table 5: WAPA invoice summary including CLFP

The largest line item overall, Network Transmission, is not the subject of this Feasibility Study. Most of the other line items would be impacted by BHE establishing their own BA, and thus are considered in our analysis. As can be seen, Regulation constitutes the vast majority of the Service portion of the invoice. The total Service portion of the invoices for the Evaluation Period totaled $2.34M, a substantial majority of which is due to Regulation. Figure 1 shows the allocation of all charges each month of the Evaluation Period and the relatively high monthly variation in these invoices. Transmission and energy sales/purchases account for much of the monthly variability.

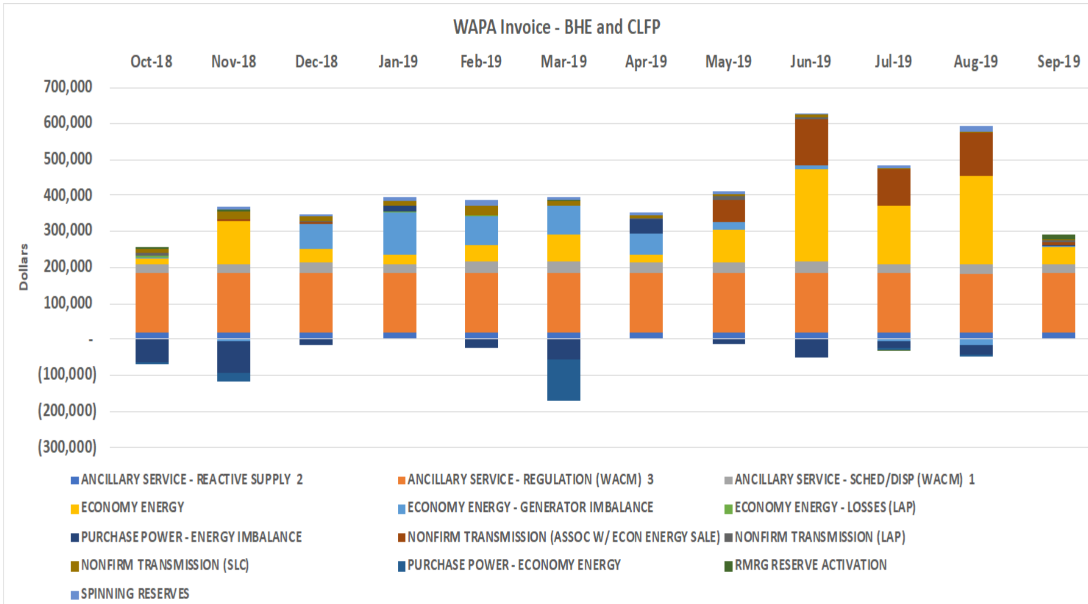

Figure 1: Evaluation Period WAPA invoice composition

Load Description

The load that was analyzed in this Feasibility Study for the BHE as BA scenario is summarized in Table 4 below.

Load	*Type of contract*	*Input data source*	*Load served from*
1. BHE load	Native load served by BHE.	BHE tab of "CUS Loads" spreadsheet.	Multiple 230 kV substations (see list below)
2. City of Gillette	Wholesale load contract to supply City of Gillette to serve its load.	Gillette tab of "CUS Loads" spreadsheet.	Wyodak 230 kV substation
3. Montana Dakota Utilities (MDU) Sheridan	Wholesale load contract to supply MDU Sheridan to serve its load.	Sheridan tab of "CUS Loads" spreadsheet.	Sheridan 230 kV substation
4. Cheyenne Light, Fuel & Power (CLFP)	Native load served by CLFP	"CLFP BA Data" spreadsheet	

Table 6: Load summary

The four load pockets listed above were summed to qual the total load obligation of the new Black Hills as a BA scenario.

The BHE as BA scenario loads are served from multiple 230 kV and 69 kV substations. For the purposes of this analysis, we assume that there are no transmission or substation constraints between any of the loads and any of the BHE generation resources listed below.

Net load in Figure 2 below represents the hourly difference between the total load obligation of the BHE BA, and historic contracted MWh from Colstrip plus wind generation in the BHE portfolio.

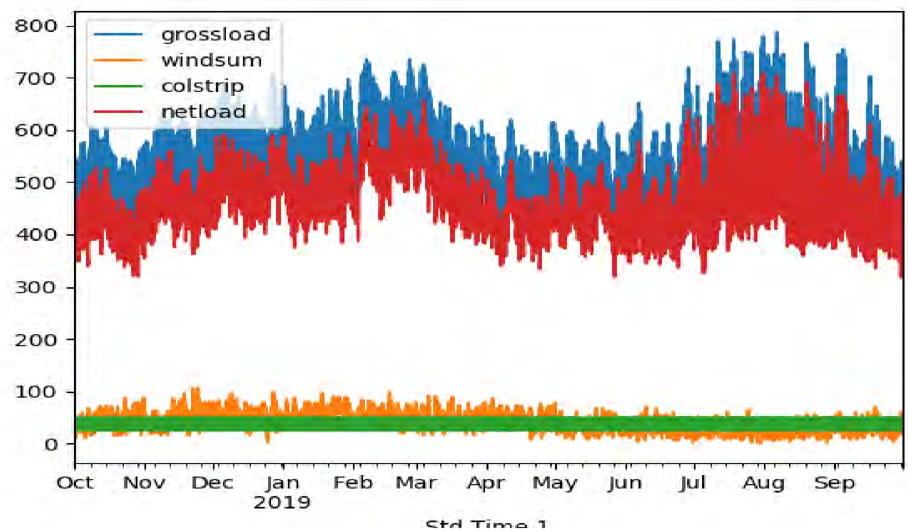

Figure 2: Annual load and PPA generation profile.

Resources and Purchase Power Agreements

Generation resources available for dispatch in the BHE as BA Scenario are defined below in Table 5:

Unit	***Available capacity for BHE dispatch (MW)***	***Ramp rate (MW/min)***	***Source to 230 kV substation***	***Owned or Contracted***
Baseload – dispatchable				
Neil Simpson 2 *(coal)*	80.0 Max 60.0 Min	1.0	Wyodak	100% BHE-owned
Wyodak *(coal)*	67.0	1.0	Wyodak	20.0% BHE-owned
Wygen 1 (coal)	5.0	1.0	unk	
Wygen 2 (coal)	90.0	1.0	unk	

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Wygen 3 *(coal)*	105.0	1.0	Wyodak	Comprised of BHE ownership plus contract.
Colstrip	50.0	25 MW/hr	Wyodak	Contracted Min/Max
Intermediate – dispatchable				
Cheyenne Prairie Generating Station (CPGS) 1 *(natural gas)*	55.0	8.0	Archer	58% BHE-owned
Peakers – dispatchable				
Neil Simpson CT 1 *(natural gas)*	39.0	8.0	Wyodak	100% BHE-owned
Gillette CT 2 *(natural gas)*	40.0	8.0	Wyodak	100% City of Gillette-owned
Lange CT *(natural gas)*	39.0	8.0	Wyodak	100% BHE-owned
Super-Peakers – dispatchable				
Ben French CTs 1 – 4 *(natural gas)*	80.0 total 20.0 each	16.0 total 4.0 each	Rapid City	100% BHE-owned
Ben French EMD 1 – 5 *(diesel)*	10.0 total 2.0 each	5.0 total 1.0 each	Rapid City	100% BHE-owned
Purchase Power Agreements				
Colstrip	50.0	0.42	unk	PPA
Happy Jack Wind Farm	29.4	n/a	Archer	BHE and CFLP each have Take or Pay PPAs for 50% of plant output. Curtailment available.
Silver Sage Wind Farm	42.0	n/a	Archer	Two PPAs for a total of 42 MW output.
Corriedale Wind Farm	52.0	n/a	West Cheyenne (new)	PPA for total of 52 MW output.

Table 7: Generation resources in BHE as BA scenario.

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Resource Economics

Generation plant unit dispatch economics as provided by BHE is reflected in Table 6 below and lays the foundation for our analysis.

Unit	*Fuel Source*	*Heat rate* (Btu/kWhnet)	*Variable O&M*[1] (*$/MWh*)	*Marginal Cost ($/MWh)*
1. Neil Simpson 2	Coal	13,343	$1.82	$15.38
2. Wyodak	Coal	13,343	$1.50	$15.12
3. Wygen 1	Coal	12,107	*$1.75*	*$14.10*
4. Wygen 2	Coal	12,107	*$1.75*	*$14.10*
5. Wygen 3	Coal	11,904	$2.18	$14.43
6. CPGS 1	Natural Gas	7,559	$4.26	$20.32
7. Neil Simpson CT 1	Natural Gas	10,162	$1.39	$24.23
8. Gillette CT [2]	Natural Gas	10,168	$5.04 [2]	$27.92
9. Lange CT	Natural Gas	10,162	$0.37	$23.23
10. Ben French CTs 1 – 4	Natural Gas	15,526	$0.64	$35.56
11. Ben French EMD 1 – 5	Diesel	13,000	$0.54	$195.53

Table 8: Unit economics for BHE-owned dispatchable plants.

Table 7 shows the $/MWh price for electricity obtained by BHE through the three PPAs indicated, one with Colstrip and two with wind farms, plus the Corriedale price as derived below.

Unit	*Fuel Source*	*PPA cost* (*$/MWh*)
1. Colstrip	Coal	$22.26
2. Happy Jack Wind Farm	Wind	$50.47
3. Silver Sage Wind Farm	Wind	$63.64

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[1] Variable O&M based on year 2021 projection provided by BHE.

[2] The Gillette CT 2 variable O&M cost also includes non-O&M factors related to the owner's desire to limit the dispatch of this plant.

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4. Corriedale Wind Farm	Wind	$37.00

Table 9: Power purchase agreement economics.

Table 7 assumptions follow:

- Corriedale PPA prices estimated by using average LCOE for utility-scale on-shore wind from Lazard Levelized Cost of Energy Analysis – Version 13.0, November 2019, https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf.

Model Description and Assumptions

Using the above-described data as inputs, we have included the following assumptions in our modeling and analysis of the BHE as BA scenario.

1. The BHE as BA model is based on the hourly load and generation data provided for the period 10/1/2018 – 9/30/2019 (Evaluation Period). For the purposes of comparing alternatives, we use this same data for consistency.
2. The analysis considers load and generation without transmission, substation, or other constraints between generators and loads within the BHE as BA service territory.
3. Transmission and Distribution losses within the BHE as BA service territory are not considered.
4. Balancing Authority requirements are based on the NERC BAL requirements in effect at the time of this analysis.
5. Wind PPAs are treated as "take or pay".
6. The analysis incorporates only the generator characteristics included in Table 3. Other characteristics such as minimum off time and minimum run time are not considered in this analysis.
7. Hourly wind farm output is deterministically simulated by averaging actual hourly wind farm output between 2010 and 2018 into an hourly average generation profile. This hourly average profile, scaled to reflect the size of the wind project and BHE's ownership share, is the assumed wind farm generation profile for Silver Sage, Happy Jack and Corriedale in our analysis.
8. The analysis makes the simplifying assumption of 100% availability of all generating units (no scheduled or unscheduled downtime is modeled). This assumption is consistent across all scenarios, thereby enabling accurate comparison between modeling scenarios.
9. No generator unit maintenance, outage periods or schedules are included in our analysis.
10. As directed by BHE, the market price at Palo Verde, subject to certain constraints discussed in the Market Reference Price section below, is used as the market reference price for the generation unit dispatch versus market purchase decisions.

11. For the purpose of estimating the cost to run dispatchable generation, the following fuel cost assumptions are used:

Fuel Type	***Fuel Price***	***Notes***
Coal	$1.02/mmBtu	Coal fuel prices for the period 2019 - 2043 as provided by BHE in file “Coal_VOM.xlsx”. Price indicated is for 2021.
Natural Gas	$2.25/mmBtu	As provided by BHE via email response
Diesel Fuel	$14.66/mmBtu	Diesel forecast provided by BYP in file “2020 Budget_Diesel forecast.xlsx.” Price indicated is average of 2021 monthly estimates.

Table 10: Fuel cost assumptions.

Optimal Dispatch Results

The generation dispatch of the economic dispatch analysis is shown in Figure 3 and Figure 4 for a representative heavy load week and a representative light load week respectively. As is evident in both Figures, these represent theoretical optimal dispatch within the unit constraints and market price signals provided (Optimal Dispatch). Of note, there are periods when market price signals would dictate dramatic unit turn-down in favor of market supply, particularly during light load weeks. Pure economic dispatch is useful to identify the upper bound on portfolio optimization value. The realities of unit cycling, transmission constraints, market liquidity, and price elasticity result in actual dispatch patterns different to what is economically optimal. We discuss this in detail later in the analysis.

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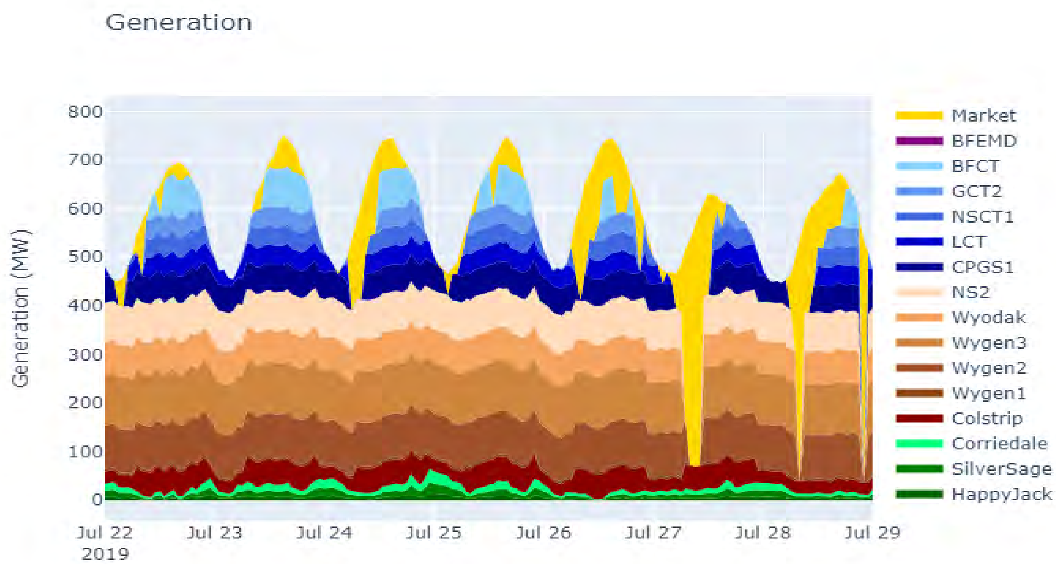

Figure 3: "Optimal Dispatch" model results, heavy load week

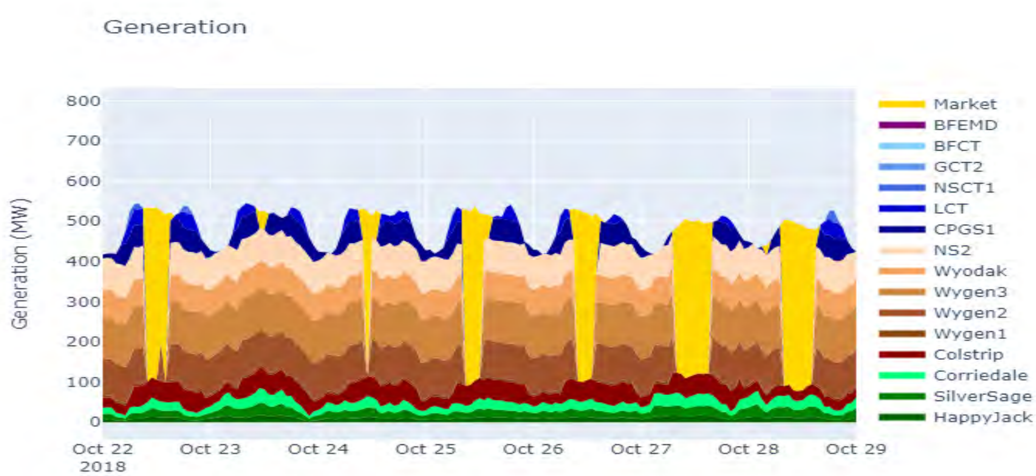

Figure 4: "Optimal Dispatch" model results, light load week.

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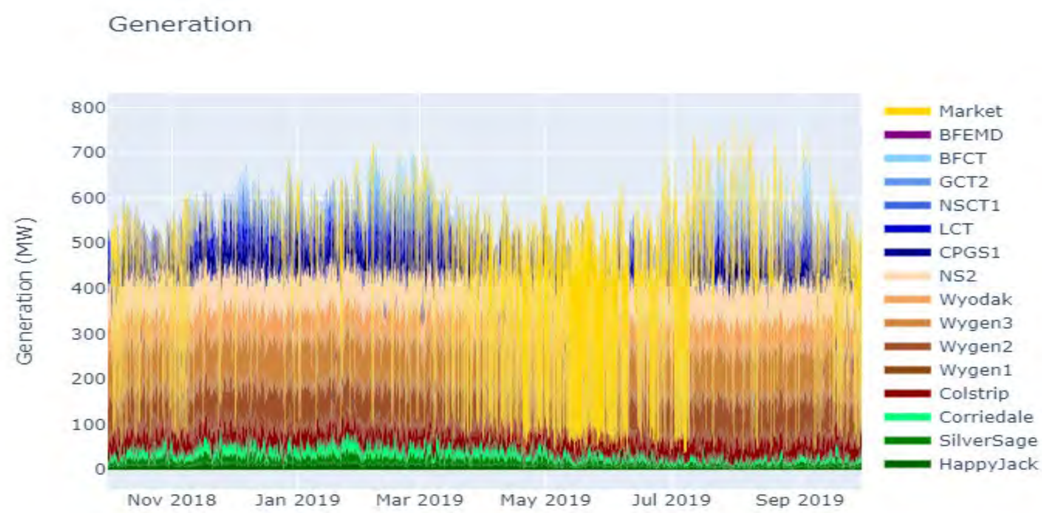

Figure 5: "Optimal Dispatch" model results, annual hourly dispatch

Market Reference Price

After discussions with BHE, and in order to provide a market price proxy for BHE's market dispatch, real-time market prices from the CAISO production OASIS were downloaded and collated into an 8,760 hour dataset for the period October 1, 2018 to September 30, 2019 (Evaluation Period) for CAISO node PALOVRDE_5_N101. This hourly data was corroborated by BHE as representing the continuing trend of price dampening in daylight hours as a result of proliferation of utility scale and rooftop solar on the grid. Per conversations with BHE personnel based on their empirical observation of the BHE generation fleet dispatch, any proxy price above $65/MWh was capped at $65, and any price below $18/MWh was floored at $18. These prices were then reduced by a further $5 to represent the market opportunity price for BHE real-time for the purpose of dispatching their fleet of resources. We refer to this as the "**Palo Verde Minus**" market price.

The affiliated cost associated with the generation profiles shown in Figure 3 through Figure 5 above is shown in Figure 6 through Figure 8 below. These are calculated by multiplying each generating resource's cost (either marginal cost, PPA price, or market cost) with each resource's modeled MW dispatch for that hourly generating stack. We refer to this in this Feasibility Study as the Optimal Dispatch.

As further explanation, Figure 6 below shows the dollar cost of each resource (including "Market" as a resource) in each hour during an especially high load week in July. The yellow Market band reflects the total dollars spent on market purchases that are displacing other resources when market price (Palo Verde Minus) is less then the marginal cost of the generating resource it is displacing. Note that the first occurrence of market displacement is during a few hours during the start of July 22. Looking at the graph it appears that BHE would spend roughly $1,200 per hour, buying market energy, for those hours. Now note the large, deep trough that falls within the first eight hours or so of July 27. It appears that BHE would be spending roughly $6,000 per hour, buying market energy, for those hours.

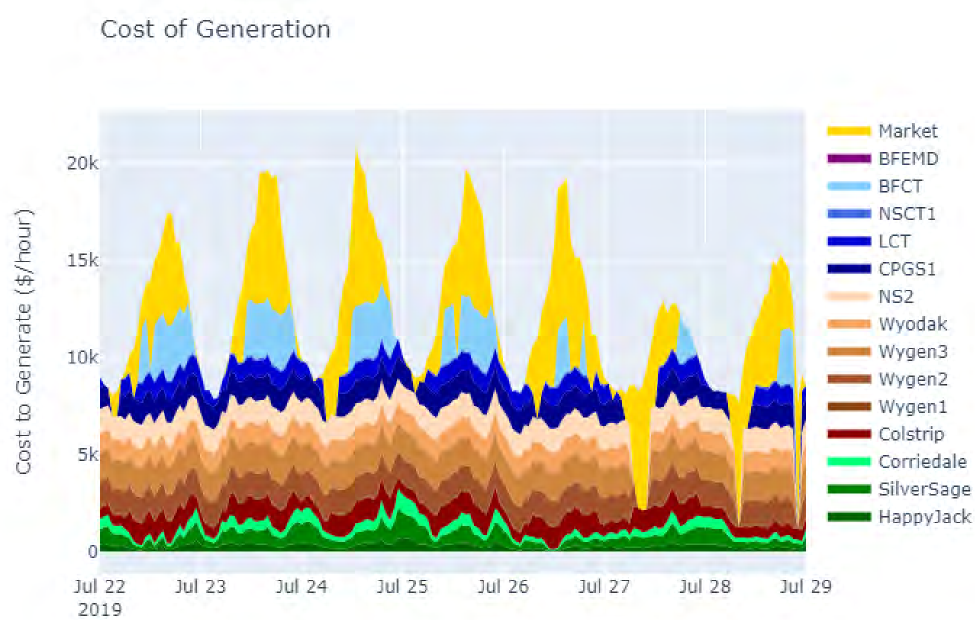

Figure 6: Modeled cost of Optimal Dispatch during heavy load week

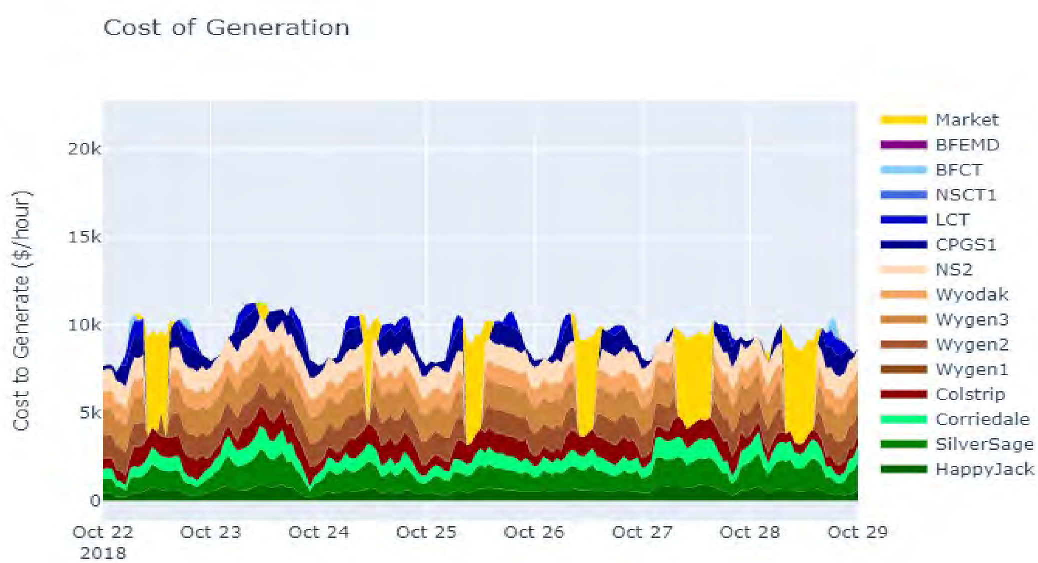

Figure 7: Modeled cost of Optimal Dispatch during light load week

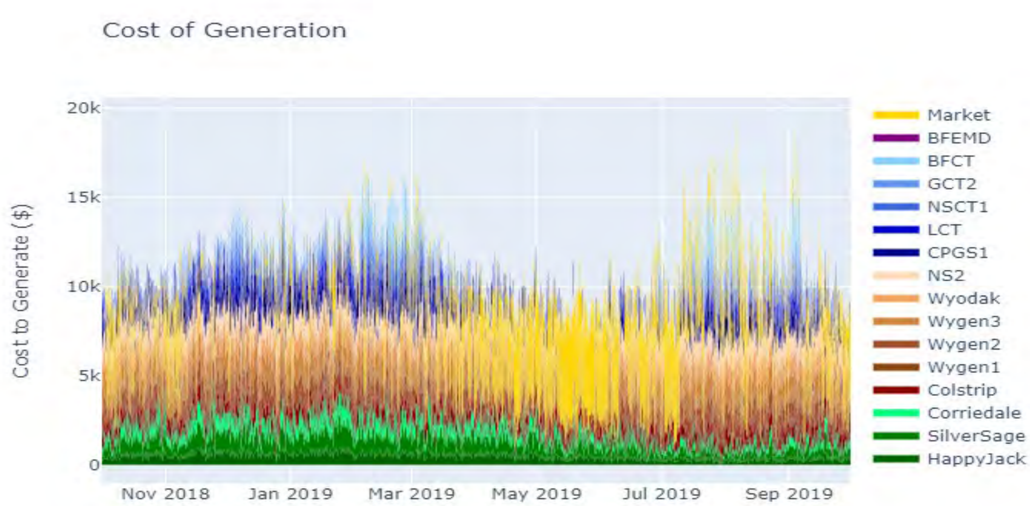

Figure 8: Modeled cost of Optimal Dispatch, Evaluation Period hourly dispatch

The Optimal Dispatch modeled cost to supply load is summarized in Table 9. The total load over the 12-month analysis period was 4,830,858 MWh, and the cost to serve load was $91,527,040. Differences between modeled performance metrics, including annual

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generation and capacity factor, are attributable to the unit generating characteristics provided and the use of the Palo Verde Minus market energy price reference as a proxy source for market energy as instructed. We realize that the reference market price (Palo Verde Minus) may not always represent the characteristics of the reference price used for historical BHE economic dispatch at all times. This is reflected in the differences between the optimal dispatch as modeled and the actual historic dispatch patterns observed. The analysis regarding imbalance later in this Feasibility Study takes this into account.

Optimal Dispatch				
	Annual Totals			
Generator	MWh Generation	Hours with Generation > 0	Capacity Factor	Cost of Generation
HappyJack	83,829		0.33	$ 4,230,851
SilverSage	126,947		0.35	$ 8,078,890
Corriedale	153,506		0.34	$ 5,679,727
Colstrip	344,200	8,760	0.79	$ 7,661,892
Wygen1	33,330	6,666	0.76	$ 469,924
Wygen2	599,940	6,666	0.76	$ 8,458,638
Wygen3	694,575	6,615	0.76	$ 9,947,759
Wyodak	430,777	6,430	0.73	$ 6,508,980
NS2	507,736	6,350	0.72	$ 7,834,290
CPGS1	266,824	5,015	0.55	$ 5,674,751
LCT	147,397	4,123	0.43	$ 3,424,692
NSCT1	105,158	3,194	0.31	$ 2,550,543
GCT2	59,425	1,902	0.17	$ 1,659,028
BFCT	34,981	813	0.05	$ 1,244,391
BFEMD	-	-	0.00	$ -
Market	1,242,234	4,941		$ 18,102,684
Sum of Wind Generation	364,282			$ 17,989,468
Sum of Coal Generation	2,610,558			$ 40,881,483
Sum of Natural Gas Generation	613,784			$ 14,553,404
Sum of Diesel Generation	-			$ -
Sum of Market Energy	1,242,234			$ 18,102,684
Sum of Generation	4,830,858			$ 91,527,040

Table 11: Optimal annual generation and cost by unit

The metric of Hours with Generation > 0 was not computed for the wind farms because a multi-year average wind generation profile was used, which, due to averaging, results in generation in every hour of the year and does not reflect the characteristics of a single year of actual historical generation.

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Note that the Ben French generating units are not dispatched in the Optimal Dispatch because the Palo Verde Minus prices are capped below the Ben French unit marginal cost of generation.

List of Balancing Standards and Analysis Plan

In order to be fully compliant as a new BA, BHE must satisfy all BAL standards as they currently exist and may change over time. Table 10 below is a list of all BAL requirements and the analysis we have employed to determine the likelihood that BHE will satisfy these requirements.

BAL Requirement	*Description*	*Analysis Plan*
BAL-001-2	Maintain ACE within prescribed limits	• An analysis of five-minute ACE data provided by BHE is compared against the BHE portfolio. • Compliance with BAL-001-2 is assessed based on meeting BAL-002 (sufficient operating reserves) and BAL-003 (sufficient frequency response).
BAL-002-WECC-2a	Maintain sufficient Contingency Reserves	• Analysis calculates Operating Reserves requirements based on historical load and generation profiles. • We have considered two scenarios: BHE as member of Northwest Power Pool Reserve Sharing Group (NWPP RSP) via contract with WAPA, and BHE as member of NWPP RSG directly.
BAL-002-3	Recovery from Reportable Balancing Contingency Event	• No Analysis required.
BAL-003-1.1	Maintain sufficient Frequency Response capability	• Frequency Bias Setting (FBS) is calculated using load and generation data. • Analysis describes the generator controls capabilities needed to meet these requirements. • Analysis includes discussion of the cost of procuring Frequency Response Obligation (FRO) compliance.
BAL-004-WECC-3	Maintain Primary Inadvertent Interchange (PII) and Time Error Corrections within requirements.	• Analysis calculates the requirement based on 150% of the data period's integrated hourly peak demand.
BAL-005-1	Data collection requirements for ACE	No power system analysis required.

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BAL-502-RF-03	Resource Adequacy Analysis requirements.	No power system analysis required.
BAL-001-TRE-1	Primary Frequency Response (ERCOT Region)	N/A for new BA scenario.

Table 12: BAL requirements and analysis summary

Analysis of Individual BA Functions and Alternatives

Scheduling, System Control and Dispatch Service

Currently BHE is charged for Schedule 1 services (Scheduling, System Control and Dispatch Service) from WAPA per their OATT rates. During the Evaluation Period BHE was charged $316,416. The rate during the Evaluation Period was $22.55 per schedule.

Assumptions on Baseline

We derived the number of schedules per year, based on the above, to be somewhere between 45 to 55 schedules (E-Tags) per day (depending on the allocation between preschedule and real-time). Based on our understanding of BHE's interactions with the market and with WAPA, this number of E-Tags seems high. In any event, it is the cost line item from above against we compare alternatives.

Alternative Scheduling, System Control and Dispatch Service Scenarios

Scheduling Alternative 1

Given the amount of tagging BHE has historically performed and the presence of an experienced System Operations team dispatching BHE's fleet on a pre-scheduled and real time basis, the incremental institutional knowledge and experience BHE must gain in order to carry out the Scheduling, Control and Dispatch functions as a BA is, in our view, limited. The NERC/WECC certification requirements are discussed earlier in this Feasibility Study. In Table 20 we detail the incremental Staffing, Systems and Administrative costs BHE will assume in order to properly execute as a BA. The sub-set of these expenses specifically related to Scheduling, System Control and Dispatch is an allocable portion of $870,000 (staffing the BA Desk as a shared resource) to $1.2M (staffing as a dedicated resource). From our experience, approximately one-third to one-half of Desk time is related to Scheduling and Dispatch. On this basis, we would estimate the internal incremental cost of providing this service to be between $290,000 per year (low case) to $612,000 per year (high case).

Scheduling Alternative 2

If BHE moves its loads and resources into the PacifiCorp East (PACE) BA, then PACE will charge per their OATT rate of $0.18/MWh during heavy load hours and $0.19/MWh during light load hours. When multiplied by the hourly load in the Evaluation Period data set, this amounts to $698,000 per year.

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Reactive Supply and Voltage Control

Reactive Supply and Voltage Control (Reactive) is a service typically provided by the Transmission Provider. It is a complicated service, the provision and compensation of which is dictated by both load and resource characteristics and is subject to detailed power flow studies that identify which resources are supplying reactive energy to which loads. We restrict our analysis to the economics of this service.

BHE spent a total of $213,551 on Reactive between WAPA BHE ($6,563) and WAPA CLFP ($206,988). For the BHE load center, BHE is charged for Reactive by WAPA for non-firm transmission procured for the sake of economy energy. WAPA charged, over the Evaluation Period, a $0.000106/MWh rate (current OATT, $0.000104/MWh) for reactive related to non-firm transmission. Since the total annual charge was $6,563, and we do not anticipate that number will increase markedly in a BHE as BA scenario as we see no reason that BHE's use of economy energy (and related use of non-firm transmission) will increase dramatically, we have not investigated this item further.

For the CLFP load center, BHE is charged for Reactive by WAPA for firm transmission service under the CLFP's *Network Integration Service Agreement No. 17-RMR-2841*, rather than under the main *Amended and Restated Contract No. 10-RMR-2098 between Black Hills Corporation [and] United States Department of Energy Western Area Power Administration Rocky Mountain Region Loveland Area Projects for Western Area Colorado-Missouri Balancing Authority Services*. We have assumed that the charges for Reactive under this NITS agreement cannot be avoided as they are assessed by the Transmission Provider based on firm transmission needed to move power from resources to CLFP's load. It is not dependent on which entity is providing the BA Services. The need for such transmission will not be obviated by BHE becoming their own BA. We therefore conclude no incremental cost/benefit for Reactive under the BHE as a BA scenario.

The above notwithstanding, in the event BHE successfully negotiates with WAPA and PACE to migrate the BHE portfolio into a PACE BA it is possible that PACE may insist WAPA Transmission procure Reactive from PACE in their capacity as new Balancing Authority even if, as assumed in this Study, WAPA Transmission continues to provide CLFP the same transmission service it has provided to date. Whether WAPA Transmission would enjoy the discretion to determine how they source Reactive as Transmission Provider to CLFP with PACE as BA is simply not clear from the PACE OATT and requires clarification from PacifiCorp. To conservatively capture the High Cost Scenario, we believe it is therefore appropriate to assume the higher PACE charge reflective of PACE's *possible* insistence that they as BA Provider provide Reactive to WAPA as Transmission Provider. This would increase the Reactive cost estimate by $292,605 under the PACE as BA scenario and should therefore be reflected in Table 26.

Frequency Response

Frequency response is the responsibility of the BA (as opposed to the Transmission Provider). As a new BA operator, BHE must be able satisfy the requirements of BAL-

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001, BAL-002 and BAL-003. This is achieved by having resources equipped and correctly coordinated (i.e. with adequate governor response capability) to respond to changes in frequency, and in sufficient quantities to satisfy the BA's NERC allocated Frequency Response Obligation (FRO). An analysis of AGC, governor dead band, governor droop settings and outer loop controls should be performed by BHE to ensure generator governors are properly coordinated to respond to a sudden change in system frequency caused by contingencies of significant magnitude (i.e. >0.070 HZ from 60.000) in the Western Interconnection.

Equipping the fleet to respond is one consideration. The other is determining how much capacity should be devoted to frequency response. Holding capacity in reserve sufficient to satisfy Contingency Reserves pursuant to BAL-002 is a requirement regardless of FRO. So long as half these reserves are spinning reserves[3], then such reserves will be in sufficient quantity to respond to a frequency event because the Contingency Reserves capacity requirement exceeds the FRO capacity requirement. If half of Contingency Reserves are not spinning, then BHE should use the following logic to estimate the MW needed for FRO sufficiency.

A frequency drop of 0.10 Hz is a conservative target for the first year of operation, and a frequency bias between 4MW / 0.10 Hz and 6MW / 0.10 Hz is reasonable given BHE's loads and resources. This translates into a requirement to commit 4-6 MW for frequency bias response (i.e. regulation) as well as Primary Frequency Response, in order to meet BHE's allocated FRO. This capacity must be spinning, and as mentioned previously, equipped with governor response capability in order to respond to contingencies which may result in frequency events.

Compliance with NERC requirements is assessed after the first year of BA operation. This is done by observing the response of Net Actual Interchange to a drop in frequency during frequency excursion events. These observations are listed on an official NERC form, (Form 2 of BAL-003), which is kept on a secure NERC site. BHE will need to supply one second Net Actual Interchange (NAI) and frequency data to complete the form. Though the test period is only 52 seconds, in order to demonstrate compliance, a data set starting two minutes prior to the event, and lasting for a total of 30 minutes is required.

BHE as BA will have the opportunity to join the NWPP Western Frequency Response Sharing Group (WFRSG). By participating in the WFRSG, all participants are entitled to calculate their annual Frequency Response Measure (FRM) in aggregate, to collectively achieve a measure that is equal to or more negative than the regional FRO. This assures sufficient Frequency Response is provided to maintain Interconnection Frequency Response on a regional basis.

In satisfying frequency response requirements, thermal generation typically is considered to perform well in the first 12 seconds but not necessarily over the entire 52 second test

[3] We realize that the BAL-002 requirement to hold half of load and generation reserves (1.5% of each) as spinning is expired.

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period used to measure Primary Frequency Response performance[4] for BAL-003, and therefore BHE has two options. It may be that BHE resources can be equipped with primary frequency response governors and configured in a way that allows them to meet frequency response. Assuming no plant hardware modifications are necessary, the cost for this modification can range from $2,000 to $4,000 per generating facility, depending on the plant configuration and DCS controls technology (ABB, Siemens, GE, Ovation, etc.).

Another option for satisfying FRO is for BHE to "procure" frequency response compliance from others. This product trades illiquidly, but in the range of $50,000 - $100,000 per MW/0.10 Hz. Since FRO through participation in the WFRSG is a regional obligation, there is no need to have a firm transmission path between the seller of such product and the buyer, and therefore BHE is free to purchase this from any member of the WFRSG regardless of their physical location within WECC. When a BA "purchases" this product, it is actually purchasing another BA's performance over and above their own obligation. If BHE concludes that procurement is more cost effective than equipping their own generating resources to satisfy their FRO, they may enter into a bi-lateral contract with another member of the WFRSG. The commercial arrangements for this type of transaction exist outside the NWPP WFRSG agreement.

Frequency Bias (β) is derived from observed BA performance against disturbance events selected by NERC for the applicable BAL-003 operating year. By observing the response of Net Actual Interchange (NAI) to a sudden change in system frequency, the FRM (expressed in MW/0.1Hz) is derived by comparing the change in average Net Actual Interchange for a selected event before and after to the change in average frequency before and after the event. The comparison time periods are:

Before the event: beginning at t-14 seconds and ending at t=0

After the event: beginning at t+20 seconds and ending at t+52 seconds

where t is the time the event took place.

The equation is:

> β = [(Mean NAI t - 14 to t = 0) – (Mean NAI t+20 to t+52)] divided by [(Mean Freq t - 14 to t = 0) – (Mean Freq t+20 to t+52)]
>
> NAI is in MW
>
> β is expressed in MW/0.10 Hz
>
> β is typically negative.

Typically, events consist of generator forced outages in which case the NAI delta (numerator) is negative while the frequency delta is positive. But there are instances where just the reverse is true (and the number is still therefore negative.)

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[4] NERC is currently evaluating BAL-003 and may make changes that are more favorable to coal resources.

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Summarizing the Frequency response obligation, we estimate the one-time cost is between $20,000 and $50,000 to equip the BHE fleet with appropriate controls. We bracket ongoing incremental annual costs in a range from zero (if capacity held idle for contingency reserves is already spinning) to $360,000 per year[5] for holding 6 MW of capacity idle. From the data and information provided, we have not been able to determine the extent to which BHE maintains capacity available and spinning under the WAPA BA. Deducing the incremental cost BHE will incur as BA to provide frequency response depends on this information. In our comparative analysis, we will assume BHE does not have capacity spinning within the WAPA BA. As a result, we treat the full spinning reserve requirement for the BHE BA as an incremental BA cost of $72,000 (4MW x $1.50/kW-mo.).

If BHE elects not to equip its own resources but rather purchase compliance from other WFRSG Member, we estimate the annual procurement cost at:

4-6 MW / 0.10Hz x $50,000 - $100,000/MW/0.10Hz = $200,000 - $600,000/year

In light of the wide range of possible economic outcomes for self-supplying frequency response, we believe BHE should confirm the cost assumptions regarding installation of frequency control governors made above against technical due diligence of the units themselves. In addition, discussions with possible third-party WFRSG suppliers of frequency response to meet FRO should be undertaken.

Regulation

Regulation is the domain of the BA provider and consists of the requirement to match loads with resources on a very short-term basis. WAPA currently controls BHE and CLFP loads, and the dynamic generation from both Silver Sage and Happy Jack windfarms. Presumably WAPA will also be providing regulation services to Corriedale wind. BHE has informed us, that although they are not a NERC certified BA with NERC reporting obligations, they do operate a sub-BA, have AGC, and operate to an ACE. Presumably this means their resources are providing some degree of regulation already.

BHE spent a total of $2,020,924 on regulation payments (which also includes frequency response under WAPA rate schedule L-AS3) to WAPA between the BHE and CLFP invoices for the 12-month Evaluation Period. If BHE were to become the BA and assume responsibility for controlling load and/or the three wind farms, then they would avoid having to pay WAPA for this service. However, the incremental operational cost to BHE of controlling to this shorter signal may result in increased O&M charges due to dispatching one or more resources on a shorter time cycle (i.e. four-second) than they are currently being dispatched. It may be prudent to technically evaluate O&M cost impact as part of the BHE BA consideration.

Again, we note that, if BHE are already controlling to an ACE, via their sub-BA, the incremental change to current resource dispatch may be due to a combination of the requirement to schedule on a shorter time increment, the addition of energy imbalance, and the addition of Happy Jack, Silver Sage, and Corriedale wind integration. We note

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[5] Based on a capacity cost of $5.00/kw-mo.

that assuming responsibility for providing regulation for all loads and resources typically necessitates also providing imbalance. The cost of possible deoptimization of the fleet to ensure fast ramp resources are always on and available, which is required to provide regulation, is subsumed in our analysis on imbalance. Therefore, we recommend that for each scenario (WAPA as BA, BHE as BA, PACE as BA), the sum of regulation and imbalance estimated costs should be considered and compared. Depending on discussions with WAPA, there may exist a scenario whereby WAPA retains the responsibility for balancing the wind generators (for example, through a firming and shaping contract), while BHE provides regulation.

BHE provided 5-minute ACE data[6] for the period 1/1/2018-10/31/2019 to serve as the basis for our analysis. This is less granular than one would normally utilize for evaluating system regulation. However, we have analyzed this data for the purposes of estimating the capability of BHE's fleet of dispatchable resources to provide regulation to total load and to non-dispatchable resources. We note that BHE data provided indicates that the fastest fleet ramping capability comes from its natural gas units, (though typically diesel generation can ramp faster). Given the relative economics and CO2/emissions trade-offs between gas and diesel, it is logical that BHE is reticent to rely on continuously running diesel generation to provide regulation. Between tighter controls on gas generation, the possibility of better controls on wind generation (for curtailment), and the addition of ACE Diversity Interchange, we believe it is possible to successfully provide regulation without relying on diesel generation.

We presume in our analysis that the five-minute ACE data provided is reflective of some degree of fleet AGC by BHE. The Evaluation Period data does not indicate which resources have been used to follow load. We understand BHE are in a transition period as the new AGC equipment is installed. We note that Woodward in their AGC report of March 13, 2019, state that *"new functionality will be added to Gillette CT1, Gillette CT2, and Lange CT applications."* This leads us to conclude that the five-minute AGC data BHE provided does not reflect AGC dispatch from these gas units, leading us to further conclude that the addition of AGC control on these fast ramp units will make it much easier for BHE to satisfy regulation requirements as its own Balancing Authority through more accurate load following than was possible prior to the AGC upgrades. We have undertaken the following analysis on the data provided:

- We have divided each five-minute data point by five to approximate a one-minute ACE ("one-minute derived ACE"). We have then parsed the one-minute derived ACE values into a histogram to analyze the ability of the fleet to respond to the load changes this data set represents, shown in Figure 9.
- We pay particular attention to the tails--data points less than -8 MW/min, or greater than +8 MW/min, since 8 MW/min is the listed ramp rate for gas resources. In

[6] We believe this data may not include Automatic Time Correction Error or Frequency Bias. However, for the purposes of this analysis we believe such is not necessary. We also noted that the dataset was inconsistent. For the period 1/1/18-1/31/19 the data provided was in five-minute increments. From 2/1/19-10/31/19 the data changed to hourly. Therefore, for this analysis we limited our use of the dataset to the time period 1/1/18-1/31/19.

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summary, over the Evaluation Period, one-minute ACE remained within this band approximately 97% of the time.

- Our understanding is that BHE's fleet is/will be substantially more responsive once AGC installation is complete at Gillette and Lange. As the above analysis suggests, small gains in portfolio response time relative to what existed during this Evaluation Period will greatly increase the likelihood that BHE can self-supply this BAA requirement.
- On BHE request, we did not include Ben French ramping capability in our analysis and no ramp rate specifications were provided by BHE.

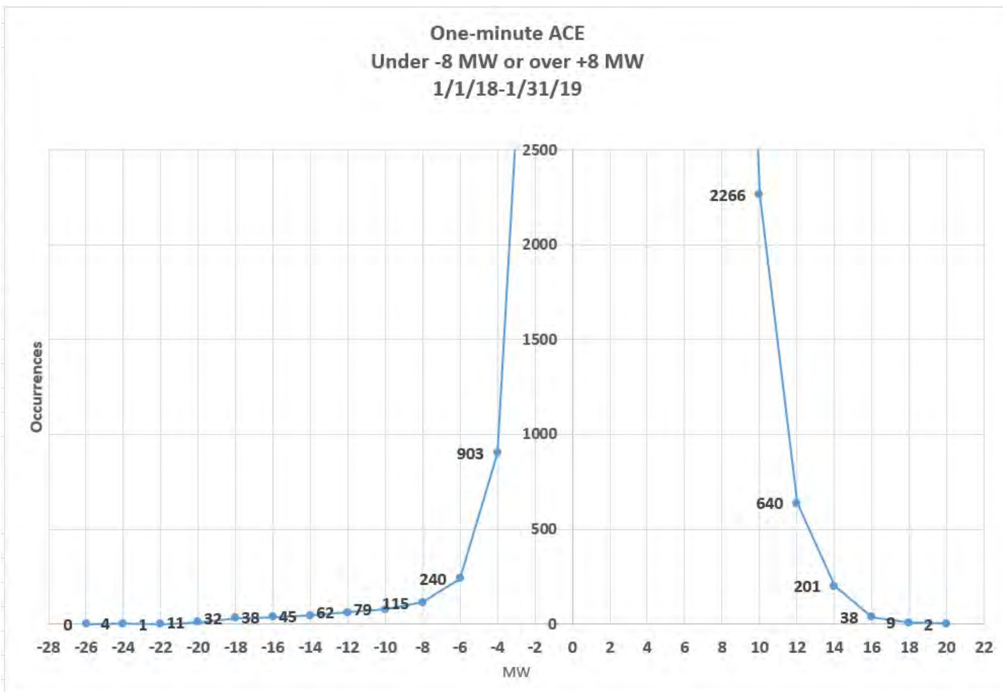

Figure 9: Histogram of ACE derived one-minute load fluctuations

<u>Ace Diversity Interchange (ADI)</u>

While the above analysis of the BHE fleet suggests the fleet improvements being made by BHE will increase the ability to meet BAL-001, ADI would simultaneously have the effect of reducing the BAL-001 requirement placed on BHE as BA. By joining the ADI collective, BHE would benefit from sharing in diversification of ACE direction with the other members. A newly created BHE BA may join the ADI collection of BAs immediately upon certification. Currently there are 11 members. This can significantly reduce the net regulation burden on the BA through its sharing mechanism. A one-time fee of approximately $35,000, and annual ongoing costs of approximately $18,000 can result in an average net equivalent reduction of ACE burden anywhere from 5-9 MW [7].

BAL-004-WECC-3

A review of the ACE data supplied, and the peak load data supplied, shows occurrences of primary inadvertent interchange (PII) in exceedance of the maximum monthly allowed. This is no surprise as we do not believe the supplied ACE numbers contained Automatic Time Error Correction (ATEC). ATEC has the practical effect of reducing accumulated PII over the measurement period to remain under the preestablished cap at the end of each month. We also note the skewed histogram above, showing a consistent tendency to over-generate. Substantial improvement is needed to approach the allowed MWh limit, which is 150% of the peak load for the month, to satisfy BAL-004-WECC-3. For BHE and CLFP loads that equates to approximately 900 MWh per month. With ATEC payback included on the EMS, as part of the BA's Reporting ACE calculation, BAs generally have little difficulty meeting this standard; we believe BHE as a BA would similarly be able to satisfy this requirement.

In summary, our analysis suggests that BHE will be able to meet its regulation requirements provided:

- AGC installation is complete on the Gillette and Lange CT units;
- System setpoints are properly designed to provide fast ramp capability to BHE as a stand-alone BA;
- ADI is in place; and
- Control logic is in place to satisfy BAL-004-WECC-3 requirements.

However, definitive conclusions will require analysis of 4 second ACE data in conjunction with technical due diligence of the AGC capabilities BHE have in place and are installing in the generation fleet.

Baseline Assumptions

The charges for regulation are divided between the WAPA BHE invoices and the WAPA CLFP invoices as described below.

The CLFP invoices show WAPA charges for regulation for only Happy Jack wind farm, according to the following:

[7] One-time costs are associated with paying a collection of third parties to set up PI and ICCP data exchange, the Western Interchange Tool, energy accounting, etc. The ongoing costs are a forecast. These ongoing costs are shared equally by all parties regardless of size. The projected "savings" of 5-9 MW is a range based on the past success of all ADI participants, and savings to BHE may be different. There is no minimum term requirement for joining ADI, neither is there any cost for discontinuing membership.

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29.4 MW x 170% x $0.23/kw-mo. = $11,495.40 per month, where 29.4 is Happy Jack maximum capacity, 170% is a multiplier for wind in the WAPA OATT, and 0.23 is the OATT rate for regulation[8].

The BHE invoices show WAPA charges for regulation for Silver Sage wind farm (under two separate PPAs) and then presumably for total load, according to the following:

30.0 MW x 170% x $0.23/kw-mo. = $11,730.00 per month, where 30 is Silver Sage maximum capacity, 170% is a multiplier in the WAPA OATT, and 0.23 is the OATT rate for regulation.

12.0 MW x 170% x $0.23/kw-mo. = $4,692.00 per month, where 12 is Silver Sage (PRPM) max capacity, 170% is a multiplier in the WAPA OATT, and 0.23 is the OATT rate for regulation.

BHE system load peaks average approximately 600 MW and regulation is charged without the 170% multiplier for wind generation. In September 2019 the bill was:

610.28 MW x $0.230009/kw-mo. = $140,370, where 610.28 is total load, and 0.230009 is the OATT rate for regulation.

Taking into account the rate decrease, the decrease in wind multiplier, and the likely addition of Corriedale Wind project, the forecast annual cost of WAPA regulation for BHE loads and resources is:

Total Projected Annual WAPA Charges for Regulation

Happy Jack	$ 112,405
Silver Sage	$ 160,362
Load	$ 1,537,908
Corriedale	$ 197,870
Total	$ 2,008,546

Avoiding the WAPA charges for regulation constitutes the largest potential savings to BHE for by becoming their own BA and therefore self-providing these services. This $2,008,546 figure is what we will use to compare the alternatives against.

Alternative Regulation Scenarios

Regulation Alternative 1

In this scenario BHE would self-supply regulation. The incremental hardware, software and communications cost for shifting the regulation burden from WAPA to a new BHE BA is likely already being incurred by BHE as they equip their fleet with AGC capability. On this basis, and given the discussion above, we estimate there is no upfront

[8] This was the rate in effect during the Evaluation Period. This rate is now $0.211/kw-mo., and the multiplier for wind is now 151%. The savings that result from these favorable rate changes are projected to be nearly offset by the addition of regulation charges for the proposed Corriedale wind farm.

cost to BHE for providing their own regulation, and the ongoing annual costs in imbalance.

Regulation Alternative 2

Under this alternative PacifiCorp East (PACE) would provide regulation. PACE provides Regulation and Frequency Response Service under their OATT. They differentiate between regulation for load (Schedule 3), regulation for dispatchable generation (Schedule 3 Non-VER), and regulation for Variable Energy Resources (VERs). They further differentiate VERs into uncommitted scheduling and committed scheduling[9].

As can be seen in Table 11, BHE could realize modest savings ($35,622 per year) if they have PACE provide regulation and BHE subscribes to committed VER scheduling. It would cost $201,306 more to have PACE provide regulation if BHE were to elect uncommitted scheduling.

The cost of migrating the BHE collection of loads and resources to PACE would be comprised of making telemetering and communication changes (from WAPA EMS to PACE EMS), extricating these signals from the WAPA EMS to the PACE EMS, and shifting AGC control from BHE to PACE. This is a substantial undertaking and would require the cooperation of WAPA. Without discussing this with WAPA, we do not know if WAPA would charge BHE for this time spent. Without discussing this with PACE, we do not know how much PACE would charge for time and effort spent developing primary and secondary communications links, installing Remote Terminal Units (if required), setting up their EMS system, and coordinating with WAPA. Switching BAs is infrequent enough that bilateral discussions are necessary to determine this, particularly with a utility of BHE's size and sophistication.

[9] Committed scheduling requires the customer to submit a base schedule, per a PacifiCorp vendor-supplied forecast, no later than T-57.

	WAPA	PACE Regulation Charges		Difference (negative = savings)	
	Current Rate	Generator Regulation and Frequency Response Service		Generator Regulation and Frequency Response Service	
		VER-Uncommitted Scheduling	VER - Committed Scheduling	VER-Uncommitted Scheduling	VER - Committed Scheduling
	Happy Jack	*Happy Jack*	*Happy Jack*		
MW	29.4	29.4	29.4		
Multiplier	1.51	1.00	1.00		
Rate	0.211	0.549	0.469		
month	$9,367	$16,141	$13,789		
annual	$112,406	$193,687	$165,463	$81,282	$53,058
	Silver Sage	*Silver Sage*	*Silver Sage*		
MW	30	30	30		
Multiplier	1.51	1.00	1.00		
Rate	0.211	0.549	0.469		
month	$9,558	$16,470	$14,070		
annual	$114,700	$197,640	$168,840	$82,940	$54,140
	Silver Sage	*Silver Sage*	*Silver Sage*		
MW	12	12	12		
Multiplier	1.51	1.00	1.00		
Rate	0.21	0.549	0.469		
month	$3,805	$6,588	$5,628		
annual	$45,662	$79,056	$67,536	$33,394	$21,874
	System load	*System load*	*System load*		
MW	610.28	610.28	610.28		
Multiplier	1.00	1.00	1.00		
Rate	0.21	0.177	0.177		
month	$128,159	$108,020	$108,020		
annual	$1,537,908	$1,296,240	$1,296,240	-$241,668	-$241,668
	Corriedale	*Corriedale*	*Corriedale*		
MW	52	52	52		
Multiplier	1.51	1.0	1.0		
Rate	0.21	0.549	0.469		
month	$16,489	$28,548	$24,388		
annual	$197,870	$342,576	$292,656	$144,706	$94,786
Total monthly	$167,379	$175,767	$165,895		
Total annual	$2,008,546	$2,109,199	$1,990,735	$100,653	-$17,811
			Total Difference	$201,306	-$35,622

Table 13: WAPA vs PACE Regulation Charges

Energy and Generator Imbalance

Currently WAPA provide imbalance service for both generation and load [10] (scheduled versus actual). Our review is based on:

1) WAPA invoices BHE provided which span the period from October of 2018 through September of 2019; and
2) the subsequent Excel files that BHE provided that contain the calculation of generator imbalance for Silver Sage and Happy Jack (together the total Generator Imbalance); and
3) the general imbalance for the Black Hills system (the Energy Imbalance) that BHE provided separately.

Based on our review, BHE would avoid $165,155 per year in punitive charges against WAPA's full market pricing. We also note that the estimated marginal cost of the BHE resource that would be providing imbalance ranges from $23.23/MWh to $27.92/MWh, compared to the average WAPA cost of imbalance which ranges from $16.21/MWh to $25.61/MWh.

We note, in our discussion on Regulation, that even if BHE were to provide regulation for their load and all resources including Silver Sage, Happy Jack, and Corriedale, that it may be economical to retain WAPA as imbalance provider. There is a possibility this could be done through a firming and shaping contract with WAPA and would require direct discussions with WAPA to investigate.

Assumptions on Baseline

We are assuming the following about the "baseline" against which we will measure alternatives for providing imbalance energy.

Over the review period, BHE paid $422,132 in generator imbalance charges to WAPA, and BHE received a credit of $296,417 for energy (load) imbalance. The difference between the two was not owing to consistent, simultaneous offsetting, as can be seen in Figure 4.

We note that generator imbalance charges appear on WAPA invoices two months after the fact. As we did not receive generator imbalance information for the two months prior to the Evaluation Period (October and November 2018), we used imbalance information from December 2018 through November 2019 instead. We note that energy imbalance charges appear on WAPA invoices two months after the fact. As above, we also shifted our evaluation of energy imbalance charges two months later to reflect this.

[10] WAPA's charges for "energy imbalance" include thermal plant generation imbalance and load imbalance. WAPA's charges for "generator imbalance" include only wind imbalance.

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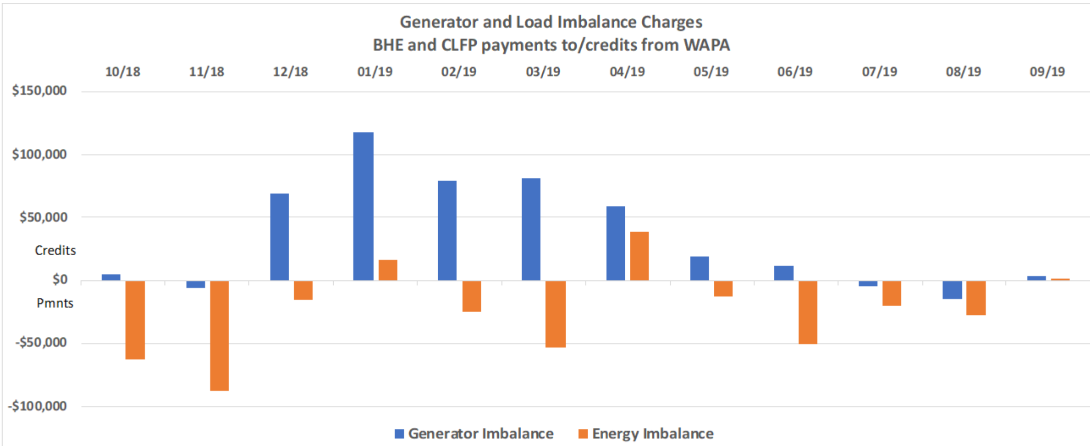

Figure 10: WAPA Generator and Load imbalance charges

Under the status quo, WAPA charges for imbalance based on tolerance bands described in their OATT, the pricing of which is according to the "weighted average real-time hourly WACM purchase/sales pricing." The tolerance bands and their associated penalties are shown in Table 12, along with the net impact of the punitive charges, as compared to the full WAPA price that BHE enjoys if their imbalance stays within the first tolerance band. Total net actual cost from Table 12 serves as the Baseline for the no Corriedale case against which we compare alternatives.

Energy Imbalance

	Billed		Punitive			
	Sales	Purchases	Sales 10% penalty	Purchases 10% penalty	Sales 25% Penalty	Purchases 25% Penalty
Band 1 (plus or minus 1.5%)	$526,838	$408,094				
Band 2 (1.5 to 7.5%)	$255,641	$158,616	$ 28,405	$ 17,624		
Band 3 (greater than 7.5%)	$2,771	$980			$ 924	$ 327

Total punitive costs for energy imbalance $ 47,279

Silver Sage Imbalance

	Billed		Punitive	
	Sales	Purchases	Sales 10% penalty	Purchases 10% penalty
Band 1 (plus or minus 1.5%)	$217,031	$277,656		
Band 2 (1.5 to 7.5%)	$264,165	$423,491	$ 29,352	$ 47,055

Total punitive costs for Silver Sage $ 76,406

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Happy Jack Imbalance

	Billed		Punitive	
	Sales	Purchases	Sales 10% penalty	Purchases 10% penalty
Band 1 (plus or minus 1.5%)	$179,530	$264,378		
Band 2 (1.5 to 7.5%)	$134,902	$295,572	$ 14,989	$ 32,841

Total punitive costs for Happy Jack	$ 47,830
Total punitive costs for all imbalance	$ 171,516

Actual Imbalance charges during Evaluation Period

	Generator Imbalance			Energy Imbalance		
	MWh	$	$/MWh	MWh	$	$/MWh
Total sales	48,937	$795,627	16.26	47,995	$785,251	16.36
Total purchases	50,360	$1,261,097	25.04	22,167	$567,689	25.61

Total net actual cost to BHE for all imbalance during Evaluation Period: $247,908.00

Table 14: WAPA deviation bands and charges

Table 13 shows a projection of these same numbers with the addition of Corriedale wind. The materially larger annual cost projection reflects the addition of 52MW of intermittent wind resource to the portfolio. Total net actual cost from Table 13 serves as the Baseline including Corriedale case against which we compare alternatives.

Projected Imbalance charges including Corriedale

	Generator			Energy		
	MWh	$	$/MWh	MWh	$	$/MWh
Total sales	91,060	$1,443,903	15.86	47,995	$785,251	16.36
Total purchases	94,590	$2,067,712	21.86	22,167	$567,689	25.61

Total net projected cost to BHE for all imbalance including Corriedale: $406,247.75

Table 15: Projected imbalance charges including Corriedale

To evaluate BHE's ability to self-supply imbalance service, we must first assess existing and projected imbalance requirements. In analyzing the current requirement for energy and generator imbalance, we assume that BHE would need capacity to provide the net hourly imbalance requirement between all loads (BHE and CLFP) and all resources (including Happy Jack and Silver Sage). For this reason we show the net hourly imbalance requirements below, in various formats, to better understand total "inc" requirements (meaning capacity increases that are needed when there is a net position short compared to schedule) and total "dec" requirements (meaning capacity decreases that are needed when there is net length compared to schedule).

Figure 11 shows the net hourly imbalance duration curve over the Evaluation Period. As can be seen, there are slightly more occurrences of net length (requiring dec) than net short (requiring inc), implying a tendency to underestimate generation or overestimate load.

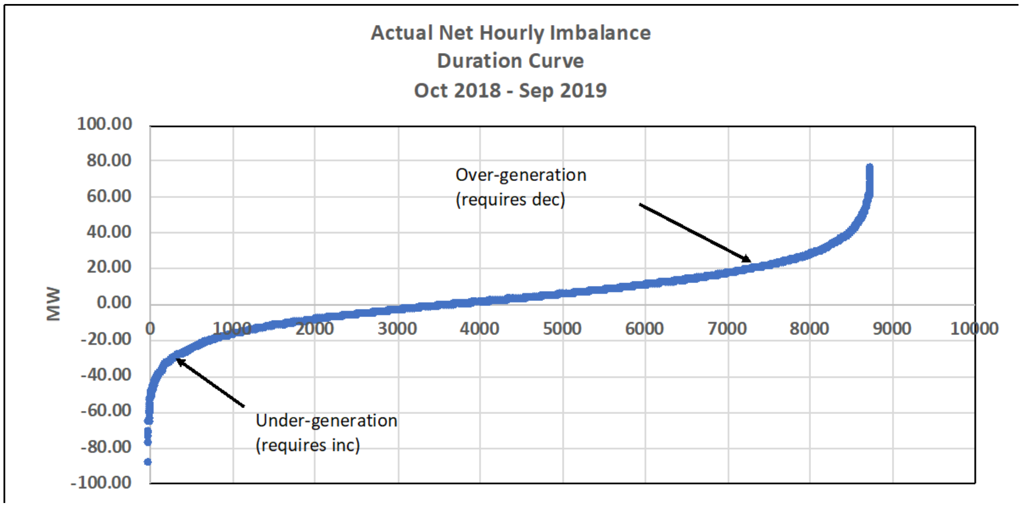

Figure 11: Net Hourly Imbalance Duration Curve without Corriedale

Figure 12 shows the same data in histogram form. As can be seen, there is only one occurrence when the MW required for dec exceeded 80 MW, and likewise only one occurrence when the MW required for inc exceeded 80 MW. Given schedules follow forecasts, this supports our finding that modestly improved forecasting could have an outsized impact on the capacity needed for imbalance.

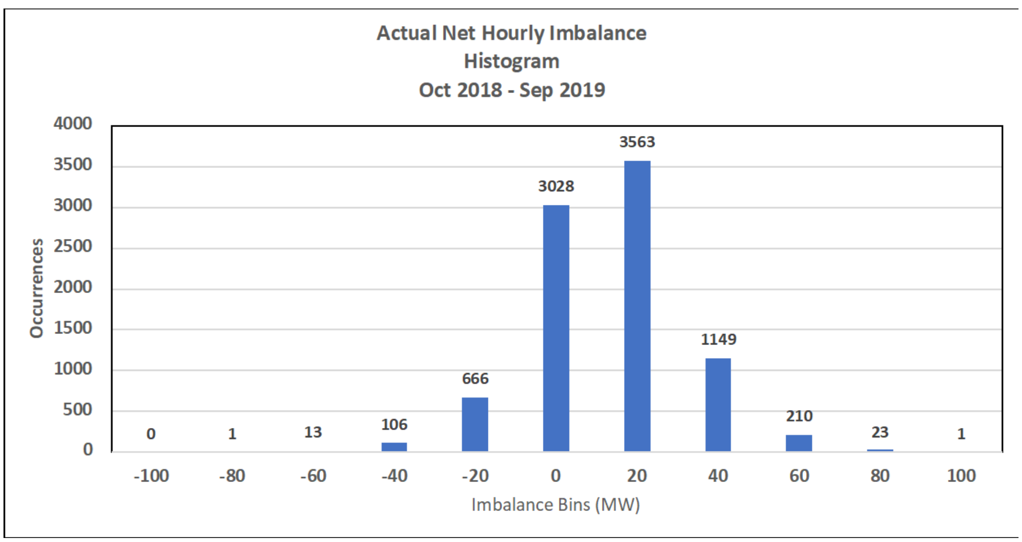

Figure 12: Net Hourly Imbalance Histogram without Corriedale

Figure 13 and Figure 14 make clear the high frequency of small hourly adjustments required of the load following units, and the low frequency of larger hourly swings which can lead to increased unit fatigue, to meet both inc and dec needs. Given how flat each of these logarithmic results is, this also reinforces the previous observation that forecasting improvements would have a material impact on capacity required for imbalance.

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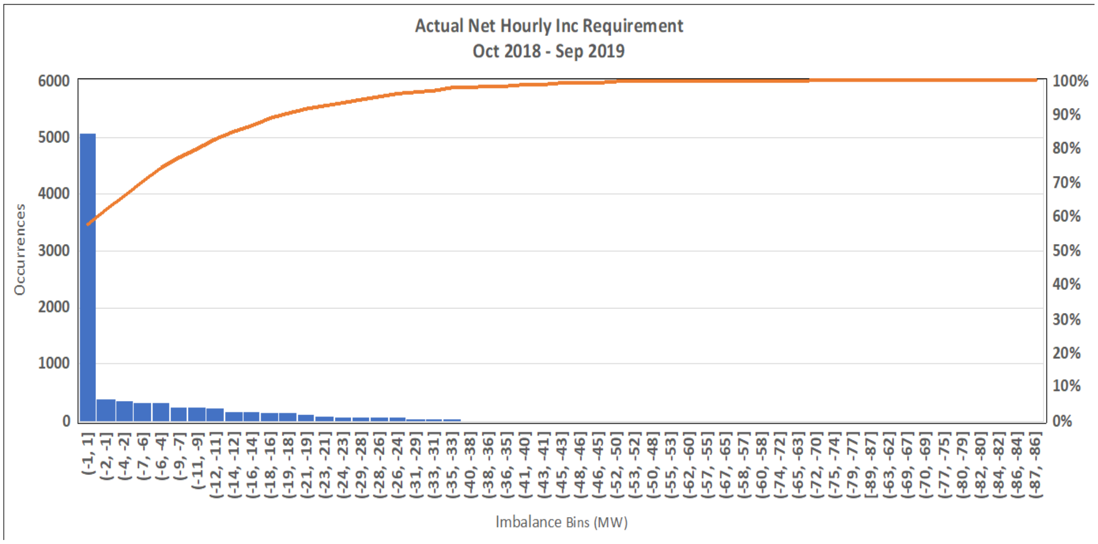

Figure 13: Net Hourly "Inc" Requirements without Corriedale

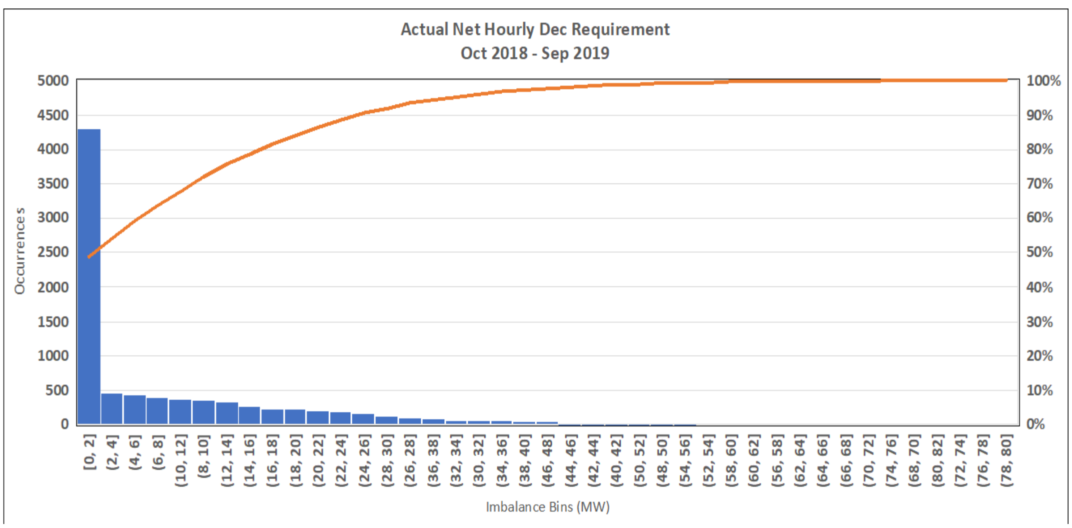

Figure 14: Net Hourly "Dec" Requirements without Corriedale

Figure 15 below is the same histogram as Figure 12 but in different format and greater granularity. Notice the flat tails of the distribution. Also notice that 55 MW of resource (CPSG1) dedicated to load following would cover 87.34% of the indicated imbalance.

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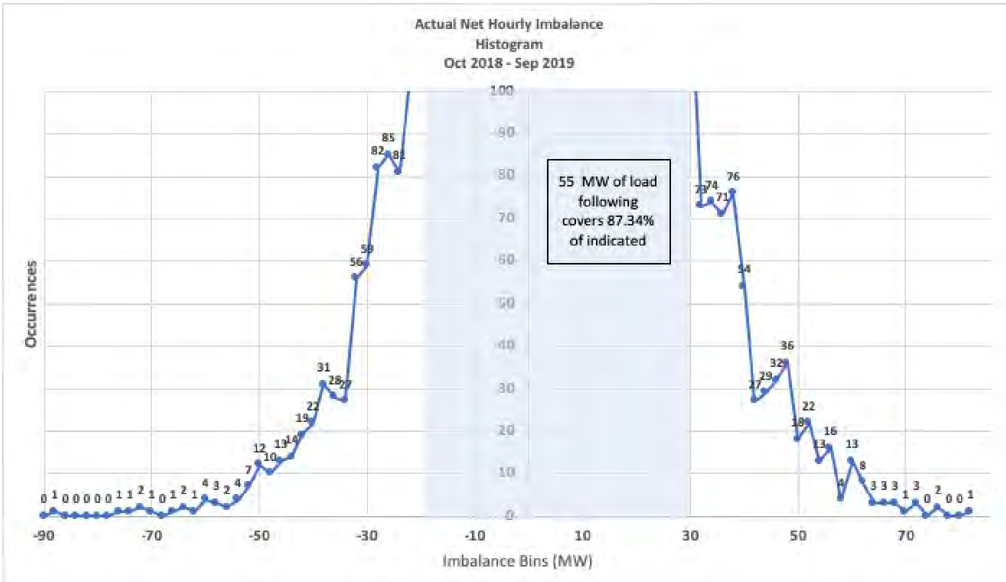

Figure 15: Actual Net Hourly Imbalance without Corriedale, % Coverage

In Figure 16 below, we see that adding 39 MW (Lange CT) of load following resource covers 98.1% of the indicated imbalance.

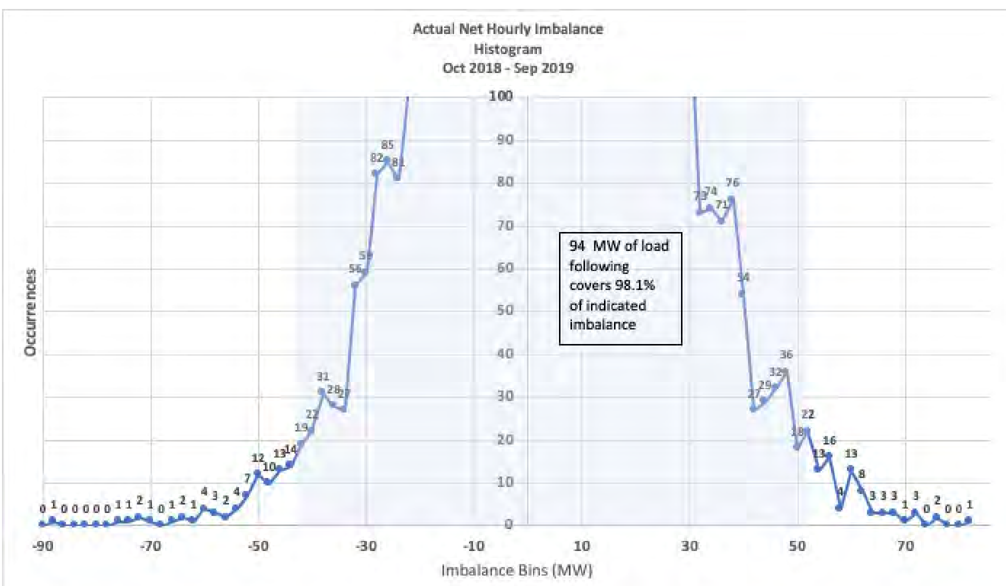

Figure 16: Actual Net Hourly Imbalance without Corriedale, % Coverage with Lange CT

Table 14 shows that the following amounts of total capacity (inc plus dec), will provide imbalance capacity necessary to satisfy imbalance for the indicated percentage of time.

MW assigned to load follow	Percent of imbalance covered
55	87.34%
94	98.11%
133	99.83%
173	99.99%

Table 16: Total "Inc" and "Dec" needed to cover indicated % imbalance without Corriedale

Baseline plus Corriedale

We are including Corriedale wind imbalance, on an incremental basis, for two reasons. First, the dataset we received pre-dates Corriedale operation and was not reflective of this additive imbalance burden. We understand that BHE is contemplating controlling all wind in the BHE BA. Second, we note that if BHE can receive a static schedule for Corriedale wind via a firming and shaping arrangement with WAPA then intra-hour imbalance will not be affected. Therefore, having the relevant analysis with and without Corriedale provides meaningful information on Corriedale's incremental impact. In order to project the total imbalance requirement with the addition of Corriedale wind, we show each of the above metrics with an assumed imbalance profile for Corriedale wind added.

The Happy Jack and Silver Sage wind farms are located directly adjacent to each other in Southeast Wyoming and consequently experience very similar wind resource. It is logical to assign high correlation of generation among the three wind farms. Based on BHE guidance, we have assumed the output from the three wind farms is highly correlated. The imbalance of each wind farm was normalized by the maximum generation capacity of each farm, averaged, and then random noise was added to the Imbalance in a way that preserves the shape of the distribution, or probability that imbalance of a given magnitude will occur. The estimated imbalance was then rescaled to the planned 52.0 MW of generation capacity of the Corriedale farm.

As can be seen in the following Figures, the addition of Corriedale has increased the requirement for both inc and dec capability.

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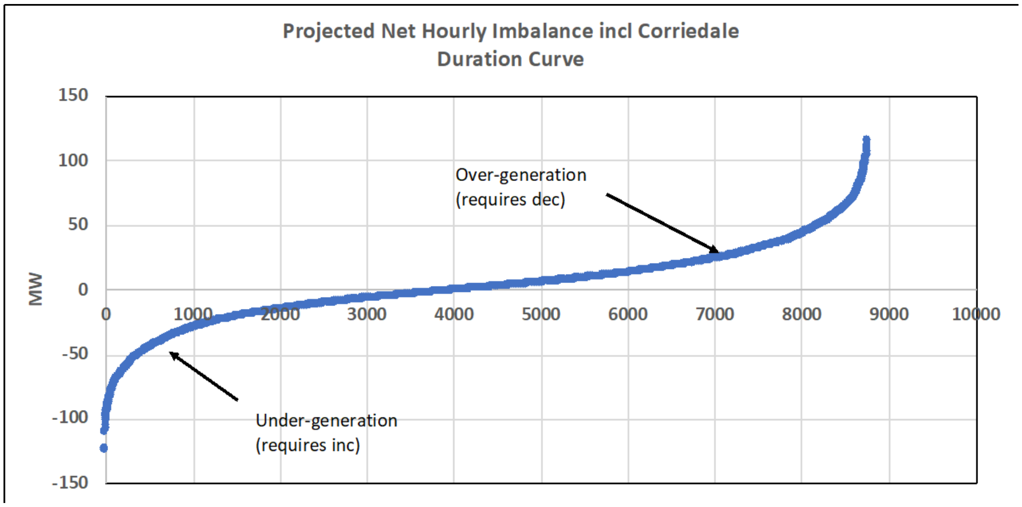

Figure 17: Net Hourly "Dec" Requirements including Corriedale

Figure 18 shows the projected inc and dec requirements with the addition of Corriedale wind. Note the relatively flat tails.

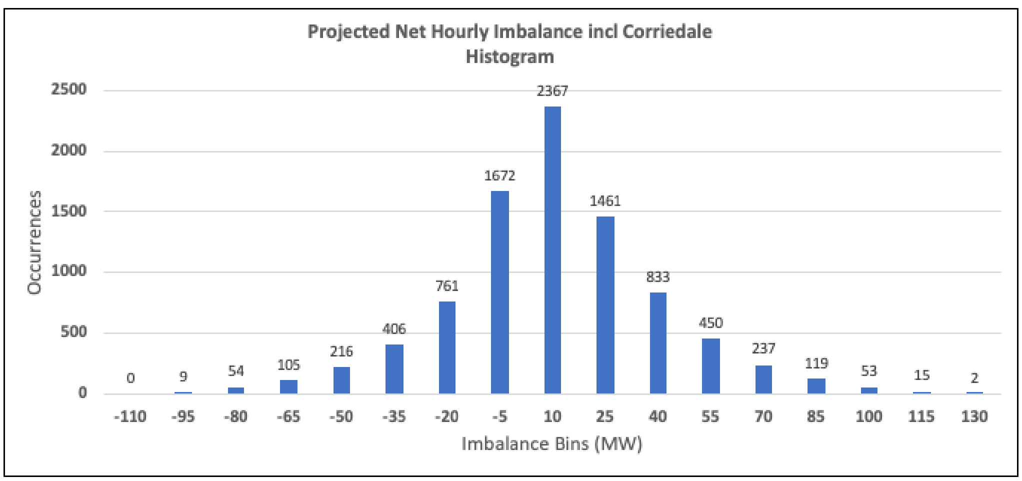

Figure 18: Histogram of projected net "inc" and "dec" imbalance, including Corriedale

Figure 19 shows projected hourly inc requirement with Corriedale wind added. As discussed above, Corriedale imbalance is projected to be highly correlated to Silver Sage and Happy Jack, which means that minor increases in forecast accuracy can have significant impacts on the amount of inc capacity necessary to provide imbalance.

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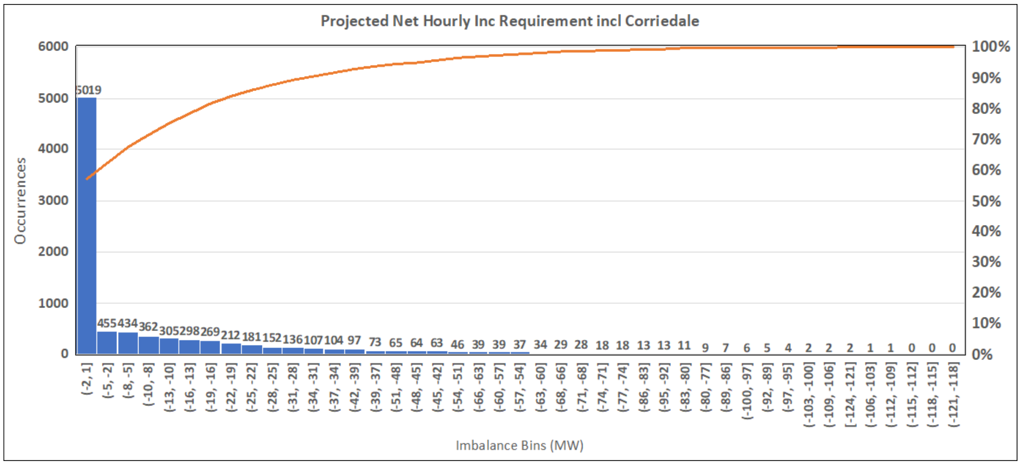

Figure 19: Net hourly "Inc" requirements including Corriedale

Figure 20 depicts the projected dec requirements with Corriedale wind added.

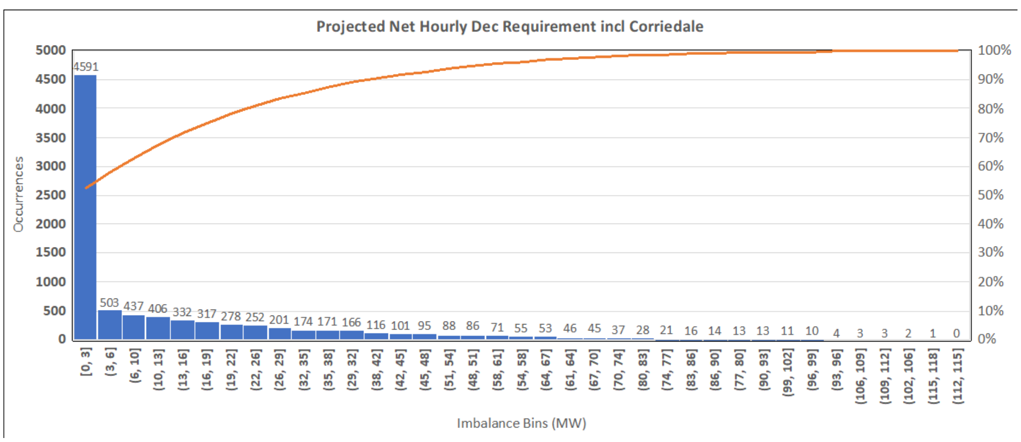

Figure 20: Net hourly "Dec" requirements including Corriedale

Figure 21 below is the same histogram as Figure 18 but in different format and greater granularity. Notice the flat tails of the distribution. Also notice that 133 MW of resource (CPSG1 plus Lange plus Neil Simpson) dedicated to load following would cover 96% of the indicated imbalance.

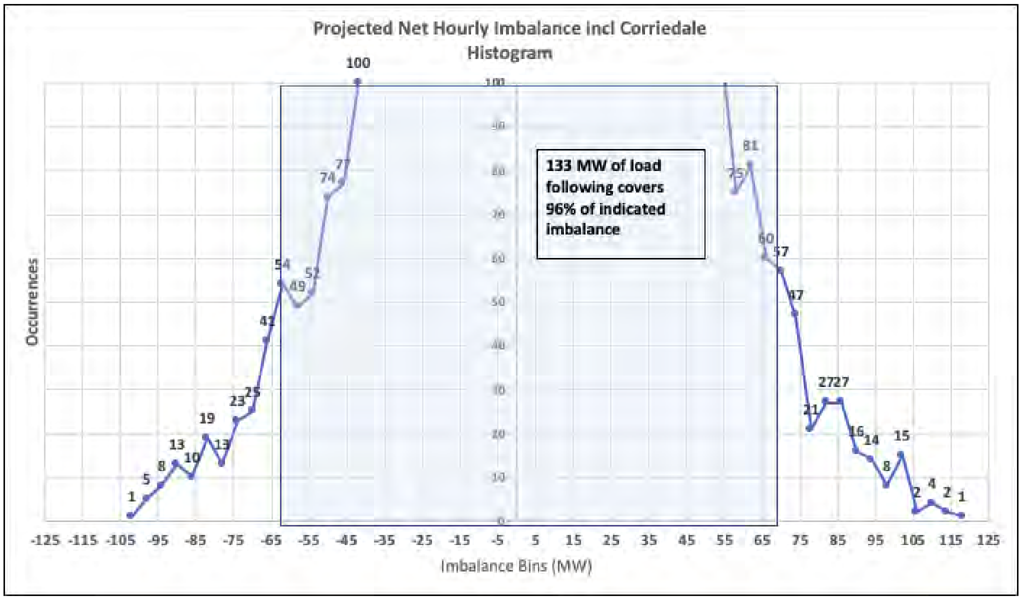

Figure 21: Histogram of Projected net Hourly Imbalance including Corriedale

This analysis shows that the amounts of total capacity reflected in Table 15 (inc plus dec), will provide imbalance capacity necessary to satisfy imbalance for the indicated percentage of time.

MW assigned to load follow	Percent of indicated imbalance covered
55	70.57%
94	87.76%
133	95.65%
173	98.86%
253	99.99%

Table 17: MW needed to load follow, including Corriedale

Alternative Imbalance Service Scenarios

We analyze three alternatives to measure against the current scenario of WAPA providing energy and generator imbalance for the total projected imbalance. As mentioned previously, a relatively small gain in forecasting accuracy could substantially reduce the amount of capacity needed for imbalance. However, for purposes of the analysis we are assuming that BHE will employ the same tools they currently use to forecast both load and generation.

Currently BHE uses their own economic dispatch logic, which includes intelligently scheduling and dispatching their fleet of resources and the Palo Verde Minus market price within real time purchase and sales timeline constraints, in merit order, to attempt to bring a balanced schedule to WAPA. BHE then relies on WAPA to provide all generator and load imbalance within-hour. We have chosen to customize this baseline for the following reasons. Though our modeling run labeled "Optimal Dispatch" has indicated significant daily displacement of the BHE fleet via market purchases (especially in light load hours), for the purposes of this imbalance analysis, we have chosen to limit the market displacement of BHE resources to a maximum of 250 MW. We do this for several reasons:

1. The model shows routine, daily displacement of 600 MW via the market, which represents an unrealistically high economic optimization compared to actual practice. Not surprisingly, we note that BHE resources, particularly coal, are not cycled as often as our economic optimization model indicates. Capping market purchases limits this displacement and the corresponding unit cycling.
2. In addition, based on our experience sourcing at Palo Verde and in other markets, we believe BHE may be able to source 250 MW at the prices indicated by the Palo Vere Minus dataset without putting undue price pressure on the market. At some level, continued purchases inflate the price with each additional purchase tranche.
3. Available transmission is also a consideration. Based on data provided, ample intertie capacity appears available for 250MW market purchases.

The result of this model run (labeled "Optimal Dispatch – limited Market") becomes our revised baseline against which to run alternatives to WAPA-provided imbalance. It shows an annual cost to serve load of $92,076,891. To this we added the total projected WAPA imbalance purchases including Corriedale of $694,454 and subtracted the projected WAPA sales of $296,417 to yield a total net cost of $92,474,928[11]. We then used this as the reference number to measure alternatives against.

Imbalance Alternative 1

In this Alternative BHE would create its own BA, discontinue purchasing imbalance from WAPA, and rely on the BHE fleet to provide the majority[12] of in-hour balancing for all loads and resources, including Silver Sage and Happy Jack windfarms, and the proposed Corriedale windfarm. As was seen in the graphical representation of Optimal Dispatch, wind resources are assumed to be non-dispatchable and therefore must run. Coal and market purchases make up the next most "dispatched" resources and, as expected, the natural gas fleet is dispatched last, given their marginal cost is highest.

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[11] Details of this run can be seen in Appendix B, "Optimal Dispatch – limited Market".

[12] This section of the report analyzes the cost of hourly imbalance. Within the hour, BHE will accrue inadvertent interchange to balance second to second variations in load and resources. The incremental cost of this Primary Inadvertent Interchange, or PII, to balance loads and resources is assumed to be zero. This is because PII shifts interchange, and therefore total system costs, between BAs on a cyclical basis, with the inherent logic of keeping accumulated net interchange to a minimum. At times, one BA may be putting energy to another BA, altering their system cost by a small degree. At other times the reverse will be true. Since this cycling takes place on a continuous basis, and is relatively small, we assume that relative economics over time will approach a very small number.

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Taking on the responsibility of providing imbalance will require some level of deoptimization of the portfolio, since gas resources (the faster ramping resources) must be positioned to provide inc and dec capability.

We then return to the histogram used to identify balancing needs and decide which resources need to be positioned to provide this balancing. Since CPGS1 is lowest marginal cost with highest ramp rate, it can cover 55 MW of the balancing needs shown in the histogram. The next gas resource in merit order is Neil Simpson CT1. This adds an additional 39 MW to further cover the balancing needs shown below. For each successive block of gas generation used to provide imbalance, we deoptimize the portfolio by using less and less coal and market resource to cover more and more of the needed imbalance burden. We perform a series of model runs to calculate the effects of progressively deoptimizing the portfolio to provide increasing amounts of load following.

For Alternative 1 -55 MWLF we have fixed the output of CPGS1 to 50% of its capacity, essentially treating 50% as must run. This is to approximate positioning CPGS1 to provide 27.5 MW of inc and 27.5 MW of dec on a daily basis. As can be seen in Table 16 below, this has deoptimized the portfolio by increasing the net cost to $93,324,918. Compared to our baseline of $92,474,928, this is an increase of $849,990.

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Alternative 1 - 55 MW LF				
	Annual Totals			
Generator	MWh Generation	Hours with Generation > 0	Capacity Factor	Cost of Generation
HappyJack	83,829		0.33	$ 4,230,851
SilverSage	126,947		0.35	$ 8,078,890
Corriedale	153,506		0.34	$ 5,679,727
Colstrip	344,200	8,760	0.79	$ 7,661,892
Wygen1	42,073	8,546	0.96	$ 593,187
Wygen2	768,017	8,669	0.97	$ 10,828,379
Wygen3	856,977	8,618	0.93	$ 12,273,686
Wyodak	457,739	7,052	0.78	$ 6,916,377
NS2	513,328	6,472	0.73	$ 7,920,575
CPGS1	240,900	8,760	0.50	$ 4,895,088
LCT	165,069	4,533	0.48	$ 3,835,305
NSCT1	131,721	3,788	0.39	$ 3,194,825
GCT2	83,096	2,497	0.24	$ 2,319,880
BFCT	56,169	1,211	0.08	$ 1,998,123
BFEMD	-	-	0.00	$ -
Market	807,288	5,496		$ 12,898,134
Sum of Wind Generation	364,282			$ 17,989,468
Sum of Coal Generation	2,982,333			$ 46,194,096
Sum of Natural Gas Generation	676,955			$ 16,243,221
Sum of Diesel Generation	-			$ -
Sum of Market Energy	807,288			$ 12,898,134
Sum of Generation	4,830,858			$ 93,324,918

Table 18: Cost of generation with 55MW dedicated to load following

From Table 15 above, committing 55MW that CPGS1 represents to load only covered 71% of modeled imbalance needs. We therefore assign increasing amounts of fast-ramp capability to the model to cover a larger percentage of the imbalance burden. Table 17 summarizes the results of incrementally committing BHE natural gas units to load following. The table shows both the incremental deoptimization (in total dollars) and the increased percent of imbalance coverage. Incremental deoptimization reflects the opportunity cost BHE suffer when higher cost units are used to load follow at the expense of lower cost units in the fleet. The details of each model run are included in Appendix B.

Resource assigned to load following	Total MW for load following (cumulative)	$ Amount of deoptimization	Percent of Imbalance covered
CPGS1	55	849,990	70.57%
CPGS2+LCT	94	2,072,451	87.76%
CPGS2+LCT+NSCT1	133	3,504,114	95.65%
CPGS2+LCT+NSCT2+GCT2	173	5,325,368	98.86%

Table 19: Summary of modeled cost of increased load-following

The modeling summarized in Table 17 assumes that the indicated amount of load following is required every hour of the year to cover the indicated imbalance. This should be viewed as the upper bound on modeled cost for the following reasons:

- Small improvement in load and intermittent resource forecasting accuracy significantly reduce imbalance requirements, reducing the need for MW assigned to load following. Given the relatively high amount of wind generation in the BHE resource portfolio, this is particularly important.
- The percentages indicated are annual numbers. In daily operations BHE will employ much more granular planning, including forecasting next day imbalance, prices, and fuel cost. BHE system planners can utilize their portfolio to best position the next day operation to optimize the amount of load-following needed. This will decrease the $ amount of deoptimization by allowing more favorable fleet dispatch. More MWh will be generated from less expensive coal units than from the more expensive natural gas units committed to load following.
- With a 24-hr real-time capability, BHE System Operators will monitor and refine preschedule generation and load forecasts within-day, further decreasing the load-following capacity necessarily held in reserve. This frees natural gas capacity to generate and sell to market, if favorable economics dictate.
- There may exist the possibility of entering into dynamic capacity transactions with other BAs (including WAPA) for AGC quality capacity at a price that proves less than this deoptimization cost.
- The Ben French diesel units are too expensive on a variable cost basis, relative to the rest of the fleet plus market (reflective of the $65/MWh cap), to be economically dispatched in our modeling. Clearly these units are available for fast response and would likely be occasionally deployed for load following should additional capacity above the AGC-equipped natural gas units be needed. Judging from the percent of imbalance covered in Table 17, our analysis suggests this would be rare enough to be economically insignificant.
- The economics of successive gas unit assignment is best described by a power function, as seen by the Figure 22 scatter plot below. It is likely, should BHE become its own BA, that a more optimal economic dispatch configuration for load following exists than simply walking up the natural gas merit order curve as modeled. For example, BHE may conclude an optimal allocation of load following including non-

gas resources, or BHE may conclude a combination of gas resources not in merit order is sufficient.

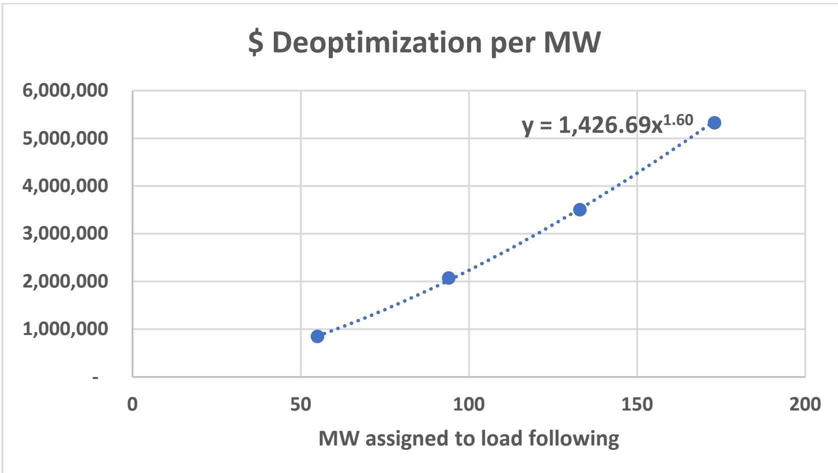

Figure 22: Modeled cost of MW held for load following.

Imbalance Alternative 2

Provide imbalance for load, but not for wind. In this scenario we assume that wind will continue to be statically scheduled into the BHE BA, and therefore the only imbalance burden will be due to energy imbalance. We note, in our discussion on Regulation, that even if BHE were to provide regulation for their load and all resources including Silver Sage and Happy Jack, that it may be economical to retain WAPA as imbalance provider for Corriedale. There is a possibility this could be done through a firming and shaping contract with WAPA particularly if WAPA view Corriedale output as less highly correlated to their overall wind portfolio.

Figure 23 below shows the histogram of energy imbalance only (no Silver Sage, Happy Jack, or Corriedale wind imbalance). As expected, given the relative ease of load forecasting compared to wind generation forecasting, the tails of this distribution are flatter than when wind generation is included in the hourly imbalance calculation.

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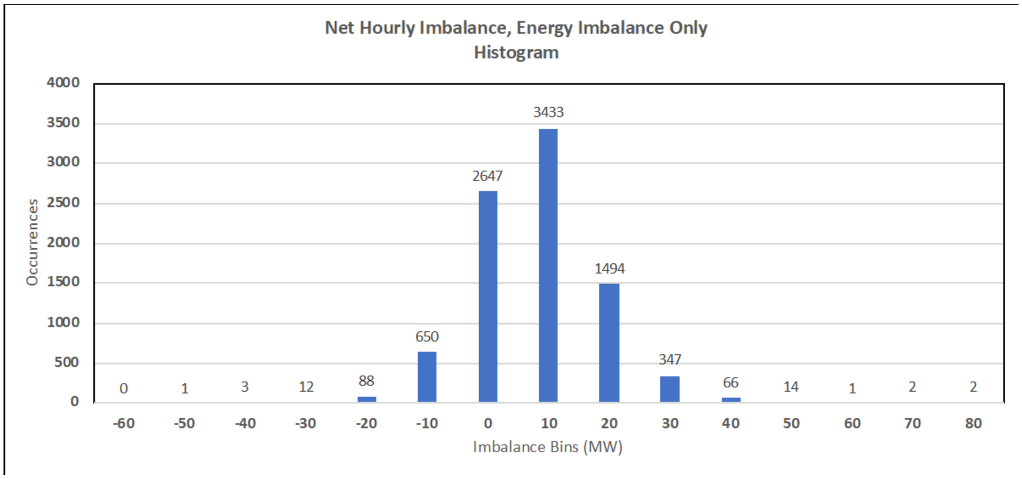

Figure 23: Histogram of net hourly imbalance, energy (load) only

For this scenario, much less gas resource is needed to meet balancing requirements, and therefore less coal and market is deoptimized, as Figure 24 makes clear when compared with Figure 21. Note that 55 MW of load following covers 98.65% of energy imbalance, whereas 133 MW is necessary to achieve comparable load following cover when all wind is included.

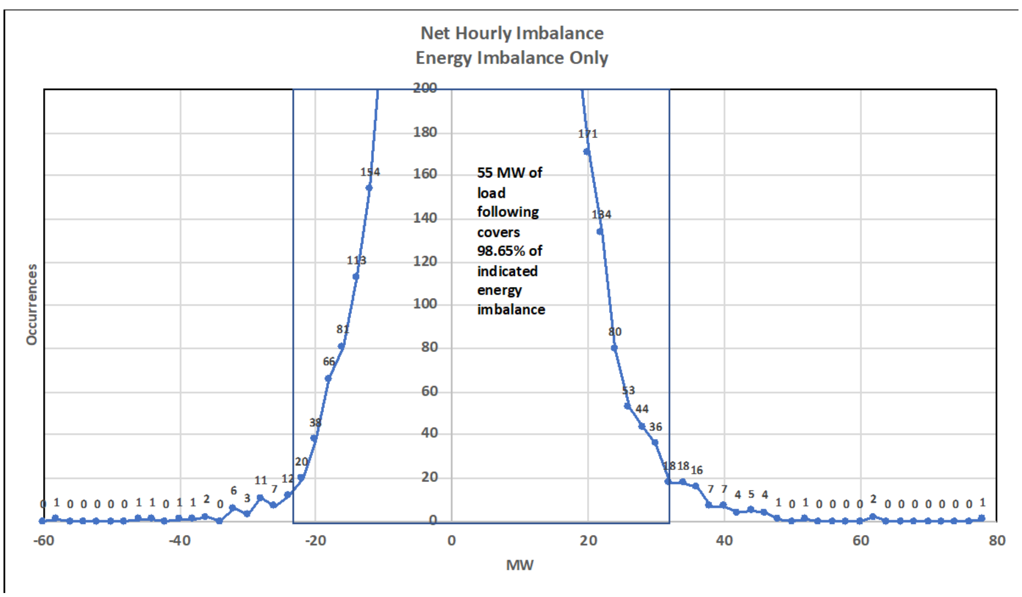

Figure 24: Net hourly imbalance, energy (load) only

The tabulated equivalent to Table 15 is shown below for this load only imbalance scenario.

MW assigned to load follow	Percent of imbalance covered
40	94.69%
45	96.70%
50	97.95%
55	98.65%

Table 20: MW needed to load follow, load only (no wind)

Imbalance Alternative 3

Procure imbalance service from PacifiCorp East (PACE). In this scenario BHE would procure balancing services from PACE. PACE provides energy imbalance service under Schedule 4 of their OATT, and they provide generator imbalance under Schedule 9. Interestingly, PACE do not impose deviation charge penalties outside pre-defined tolerance bands. PACE applies CAISO pricing to over-generation and under-generation for both load and generator imbalance.

As previously discussed, it should be noted that an estimate of the cost to move loads and resources from one BA to another was not completed due to the lack of necessary information for this assessment.

For energy (load) imbalance, PACE uses the uninstructed energy charge at the Load Aggregation Point (LAP). PACE maintains a spreadsheet of this settlement data on their OASIS. Prices are subject to correction at various times after the fact (for instance, prices are verified 12 business days after the fact, then again at 55 days after the fact). Prices remain subject to correction until nine months after the fact. For purposes of this Feasibility Study, the "oldest" or most-verified prices for each applicable period were used[13] and applied to the hourly energy imbalance for the Evaluation Period.

For generator imbalance PACE uses the uninstructed energy charge for the Fifteen Minute Market PNode located at the generator. The nearest PACE PNode to where the three wind farms are located is FOOTECRE_NODE2. Therefore, pricing data from the CAISO production website was downloaded for the Evaluation Period and applied to total generator imbalance from all three wind farms.

As can be seen in Table 19 below, if PACE were to provide imbalance, BHE would cross over from paying for imbalance to being credited for imbalance. This is due to the higher prices PACE would have paid for energy imbalance (sales). Since BHE was a net over-generator of energy imbalance, and the PACE price averaged $30.76/MWh versus WAPA's $16.36, BHE collected much more for imbalance sales per the PACE OATT. Compared to the base case, BHE would improve their net position, if PACE were to provide imbalance to both generation and load, by the difference between a cost of $247,908 and a credit of $573,716, or $821,623. These numbers are without the addition of Corriedale.

[13] For the portion of the Evaluation Period 10/1/2018-1/31/2019, PACE T+9 months data was used. For the Evaluation Period 2/1/2019-7/31/2019, PACE T+55 days data was used. For the Evaluation Period 8/1/2019-9/30/2019, PACE T+12 days data was used.

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While our analysis is based on historic BHE imbalance performance, it is worth noting that certain Balancing Authorities require, as a condition of service, that utilities within their BAs apply reasonable efforts to achieve a flat portfolio on at least a pre-schedule basis. Systemic over- or under-generation relative to load by those utilities within their BAA may be discouraged in such cases through the threat or application of persistent deviation charges. We assume no PACE persistent deviation charges in the below analysis.

Projected Imbalance if PACE provides

	Generator Imbalance			Energy Imbalance		
	MWh	$	$/MWh	MWh	$	$/MWh
Happy Jack sales	17,964	$ 318,804	17.75	47,995	$1,476,321	30.76
Silver Sage sales	29,861	$ 533,348	17.86	22,167	$ 841,455	37.96
Happy Jack purchases	20,051	$ 377,312	18.82			
Silver Sage purchases	28,034	$ 535,991	19.12			
Total sales		$ 852,153			$1,476,321	
Total purchases		$ 913,303			$ 841,455	
Net		$ 61,150			$ (634,866)	

Total net cost to BHE for all imbalance (no Corriedale) if PACE provides $ (573,716) (net credit to BHE)

Table 21: Estimated PACE imbalance cost, no Corriedale

The Total net cost to BHE for all imbalance (with Corriedale) if PACE provides, is shown in Table 20 below.

Projected Imbalance if PACE provides, with Corriedale

	Generator			Energy		
	MWh	$	$/MWh	MWh	$	$/MWh
Total sales	87,696	1,566,589	17.86	47,995	$1,476,321	30.76
Total purchases	88,148	$1,687,069	19.14	22,167	$ 841,455	37.96
		$120,480			($634,866)	

Total net cost to BHE for all imbalance (with Corriedale) if PACE provides: $ (514,386) (net credit to BHE)

Table 22: Estimated PACE imbalance cost, with Corriedale

With the addition of Corriedale the net economic improvement of having PACE provide imbalance is greater still. The cost of WAPA providing all imbalance including Corriedale is $406,248 and the estimated cost of PACE to provide the same is a credit of $514,386. This is a net gain to BHE of $920,634.

<u>Summary Observations on Imbalance</u>

Estimating the cost of imbalance service is both difficult, and key to the decision to become a BA. Our analysis on imbalance contains assumptions that likely add layers of conservatism to our findings. For example, while we assume that BHE employs hourly economic dispatch to minimize imbalance charges from WAPA, in our view, taking on full BA responsibility is likely to increase internal focus on System Operations.

We also acknowledge that coal units may be selectively used to satisfy intra-hour imbalance needs. We have not reflected this in our analysis. Though market purchases are static schedules and provide no intra-hour flexibility, we note that intra-hour markets continue to gain popularity and liquidity, offering yet another tool for managing intra-hour variability, which would serve to reduce the deoptimization our models indicate.

Throughout the Feasibility Study we mention the possibility of firming and shaping arrangements with WAPA whereby WAPA would retain the responsibility to provide imbalance and regulation to wind and provide a schedule to BHE as they are currently doing. WAPA is a large system with surplus flexibility and therefore they may be interested in retaining the revenue they currently see from providing this service.

We do not assign any capacity benefit that may be attributable to wind production, we have only examined the cost implications in our dispatch model, nor have we considered the possibility of utilizing wind curtailment as an additional balancing tool.

Reserves

Description of how BHE currently complies with BAL-002

Currently BHE meets its Contingency Reserve Obligation (CRO) by contracting with WAPA via the agreement titled "*Reserve Sharing Agreement by and between Black Hills Power, Inc. and United States Department of Energy Western Area Power Administration Rocky Mountain Region*." This agreement essentially allows BHE participation in WAPA's membership in the Northwest Power Pool Reserve Sharing Group (NWPP RSG). WAPA has a total reserve obligation to the NWPP RSG and allocates a pro-rata portion of that requirement to BHE based on BHE's calculated CRO. BHE can call upon reserves during a disturbance control event and pay for energy dispatched to them. They are also responsible for providing reserve energy (and being compensated) when called upon. The combination of the BA agreement with WAPA and the reserves agreement with WAPA provide all necessary ancillary services required to balance BHE's loads and resources.

BAL-002 Most Severe Single Contingency consideration

According to NERC/WECC balancing standards, BAs must calculate their MSSC and, absent participation in an RSG, keep capacity idle consistent with that calculation. We have reviewed the BHE proposed portfolio and corresponding transmission system in order to estimate the MSSC. Given that potential transmission constraints between Reserve Sharing Zones is a consideration for calculating MSSC, we must consider two questions. First, what portion of the year will BHE be dependent on imports in order to meet its load; and second, have there been routine transmission constraints in the past between the Reserve Sharing Zone in which BHE's BAA will ultimately reside (the Western Colorado zone), and adjacent zones (Eastern Colorado, High Desert), such that reserve energy has not been able to flow? In answering the first, we note that for nearly all hours of the year BHE is able to meet its load from its own collection of resources and

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need not rely on imports from outside the BA. Beyond that, we note that BHE has indicated the following import capabilities from what would be adjacent BAs.

- 478 MW bi-directional capability between CUS 230 kV and PacifiCorp 230 kV (Tongue River to/from Sheridan)
- 419 MW bi-directional capability between CUS 230 kV and PacifiCorp 230 kV (Hughes to/from Wyodak)
- 200 MW bi-directional capability between CUS 230 kV and SPP (South Rapid to/from Rapid City DC tie)
- 190 MW bi-directional capability between CUS 230 kV and WAPA 230 kV (Westhill to/from Stegall)
- 450 MW bi-directional capability between CUS 230 kV and PacifiCorp 230 kV and WAPA 230 kV (Windstar to/from Dave Johnston)
- 442 MW bi-directional capability between CUS 230 kV and PacifiCorp 230 kV (Teckla to/from Antelope Mine)

Total transfer capability to adjacent BAs = 2,179 MW

In answering the second we rely on conversations with the NWPP RSG personnel who opine that such occurrences have a very remote possibility. Given that zonal congestion will almost never be an issue, we then look at the maximum amount of capacity that is dispatchable from the portfolio to establish MSSC. Since Wygen III is a single unit and constitutes the maximum capacity that BHE has rights to, the 105 MW of Wygen III constitute what will be the MSSC for BHE most of the time. (If BHE could not join the NWPP RSG this would be the amount of dispatchable capacity BHE would need to keep idle or procure through a purchase of reserve capacity in order to meet balancing standards related to reserves.) On very rare occasions where multiple contingencies happen simultaneously (multiple BHE resources are unavailable, wind generation is low, loads are extreme, etc.) then BHE may be reliant on imports, and the MSSC in real-time may have to be determined by comparing the transfer capability between BHE BA and adjacent BAs to BHEs then-available resources.

Satisfying BAL-002 is a real-time obligation, meaning that BHE must continuously update the CRO calculation, continuously supply the calculated level of reserves, and supply real-time information to the NWPP RSG. Calculating CRO is a four-step process:

Step 1 - Calculation of Participating Balancing Authority Base Contingency Reserve Obligation

Step 2 - Check for Deficiency Related to Most Severe Single Contingency for the NWPP

Step 3 - Check for Deficiency Related to Most Severe Singe Contingency for a Reserve Sharing Zone and Sum of Adjustments

Step 4 - Calculation of Aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group and Check for NWPP Reserve Sharing Group Shortfall

<u>BAL-002 Alternative 1: Direct Membership in NWPP Reserve Sharing Group</u>

As a balancing authority in the Western interconnection BHE has the obligation to join the NWPP. This will give them ability to directly join the NWPP RSG (versus having a virtual membership through WAPA). Doing so allows BHE to be allocated a CRO that is typically less than their MSSC. According to the RSG calculation for CRO, if the combined "base CRO" of the Group participants is greater than the highest MSSC for the region, then each participant is only obligated to hold in reserve its individual base CRO. In the case of BHE being their own BA, this would amount to 3% of load plus 3% of actual generation. Based on hourly load date for the combined BHE and CLFP systems, loads ranged from a low of 398 MW to a high of 787 MW, with an average of 551 MW. This would translate into a CRO obligation of 24, 47, and 33 MW respectively. This is significantly less than the MSSC of 105 MW.

A comparison of the value of capacity associated with 105 MW MSSC versus 21 MW of CRO yields the following savings available if BHE continues to enjoy the benefits of having access to the NWPP RSG.

Annual net savings from RSG membership

Capacity value ($/kw-mo.)	Savings ($)
5.00	4,730,176
7.50	7,161,265
10.00	9,592,353
12.50	12,023,441

Table 23: Annual savings of NWPP RSG membership

According to NWPP policy, in order to participate in the NWPP RSG, BHE will need to become both a NWPP Operating Committee member and a Reserve Sharing Group member. Each of these come with an obligation to pay dues associated with the membership. However, this should not be an incremental cost to BHE as BHE is presumably paying its pro-rata share of these administrative costs through its current agreement with WAPA. As a direct member BHE will simply pay these same dues to NWPP directly.

As part of participation in NWPP RSG, BHE will also need to telemeter the following data to the NWPP no less than every 6 seconds.

a. the portion of its Contingency Reserve Available that is WECC Operating Reserve - Spinning ready for use as Internal Reserve or Assistance Reserve,

b. total Contingency Reserve Available ready for use as Internal Reserve or Assistance Reserve,

c. its total Balancing Authority Area Load as used to calculate its Contingency Reserve Obligation in accordance with Attachment A,

d. its total Balancing Authority Area Generation as used to calculate its Contingency Reserve Obligation in accordance with Attachment A,

e. any portion of its reported Contingency Reserve Available already in use,

f. its Reporting ACE as calculated according to the NERC glossary of terms,

g. its Most Severe Single Contingency,

h. Scheduled Net Interchange values as used to calculate its Contingency Reserve Obligation in accordance with Attachment A,

i. Actual Net Interchange values as used to calculate its Contingency Reserve Obligation (CROCA) in accordance with Attachment A,

j. its Reserve Sharing Request dynamic schedule,

k. request for Reserve Sharing Status Indication,

l. reserve sharing response.

m. indication (manually entered) of availability to provide Assistance Reserve (Participating Balancing Authorities not available to provide Assistance Reserve can still receive Assistance Reserve)

n. status of the communications links that enable it to participate in the NWPP Reserve Sharing Program on an automated basis,

o. for any Participating Balancing Authority with variable bias, its frequency bias setting.

The NWPP allocates the actual costs of Operating Committee membership and Reserve Sharing Agreement membership equally (regardless of size of load, BA, etc.) to all members. This equates to approximately $48,000 per year for Operating Committee membership and approximately $84,000 per year for Reserve Sharing Group membership. This appears to be what BHE pays WAPA through the current reserve sharing agreement with them (this is not called out separately by WAPA).

The table below shows the estimated cost of holding reserves idle based on two methods. The first method simply shows the value of capacity at various prices and MW (the minimum hourly load over the Evaluation Period was 398 MW, the average was 551, and the maximum was 787). As an example, based on average load of 551 MW, BHE would "lose" the value of capacity, which at $1.50/kw-month equates to $597,789.

Method 2 assumes that whenever real time prices are above average system cost of $19.87, BHE would sell an hourly amount of energy equal to the reserved capacity. This is quite a large number and contains a host of simplifying assumptions (i.e. gas prices are constant, fuel contracts are unaffected, transmission is available, credit is available, liquidity is guaranteed, no marginal cost considerations, etc.). We see this therefore as an upper bound on the estimated opportunity cost of reserves.

These two Methods are offered up as two potential ways to value the cost of keeping CRO capacity idle on the BHE system. BHE may very well have their own method for valuing the cost of idle capacity. Whichever methodology is used we know two things. First, the result is consistent across the WAPA as BA scenario and the BHE as BA scenario, since BHE is obligated to hold the same amount of capacity idle for each scenario. Second, we believe the obligation to pay NWPP administrative costs is also the same across these two scenarios.

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Opportunity cost of reserves - Method 1

		Capacity Price ($/kw-mo)			
		1	1.5	2	2.5
BHE Load (MW)	398	$ 287,565	$ 431,347	$ 575,129	$ 718,912
	551	$ 398,526	$ 597,789	$ 797,052	$ 996,315
	787	$ 569,682	$ 854,523	$ 1,139,365	$ 1,424,206

Opportunity cost of reserves - Method 2

Average System Cost (ASC):	19.87
Missed sales of reserve capacity at PV, minus $5, minus ASC:	$ 2,334,268

Table 24: Opportunity cost of reserves

PACE as Reserves Supplier

In the event BHE successfully negotiates with WAPA and PACE to migrate the BHE portfolio into a PACE BA, PacifiCorp may let BHE provide their own reserves, in which case the opportunity costs shown above will remain reflective of the cost to BHE for reserves. However, PacifiCorp may require that BHE abide by the PacifiCorp OATT, business practices, and OATT rate changes for reserves. Below is a discussion of what that cost could be under today's OATT. In summary, this cost could range from $729,000 to over twice that amount.

PACE charges a per-MWh charge for reserves under Schedule 6 "Operating Reserve-Supplemental Reserve Service (SU)", and Schedule 5 "Operating Reserve – Spinning Reserve Service (SP)". The unit charge is the same for Schedules 5 and 6. Per the current PacifiCorp OATT, the following language resides in both Schedule 5 and Schedule 6 descriptions:

Under the current NERC Regional Reliability Standard BAL-002-WECC, the Transmission Provider is required to maintain a minimum amount of contingency reserve equal to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation with at least half as spinning.

Consistent with the Transmission Provider operating in accordance with this reliability standard, the charges for Schedule 5 (and, independently, for Schedule 6) *below apply one and one-half percent to load and one and one-half percent to generation.*

It is clear that charges equal to one and a half percent of load and resources would be levied by PACE. This equates to the $729,000 shown in Table 25. However, since BAL-002 has been modified to not require reserves to be spinning, we are unsure if PacifiCorp would continue to charge the current rate for this service, or alter the charge, or even remove the charge for the other one and a half percent. Without discussing this with PACE it is difficult to make a conclusion. We have decided therefore that it is prudent to include these Schedule 5 and 6 charges in the High Cost Scenario. Given that BHE resources may exceed BHE load if BHE were to migrate to the PACE BA (for, say, economic opportunities brought about with the ability to dispatch into the EIM), it is prudent therefore to add at least another $729,00 to the estimated reserves component for the PACE as BA scenario in Table 26.

Implementation Timeline

Should BHE decide to become a Balancing Authority, we estimate a 9 to 16-month implementation timeline. We have broken this out in Figure 15 into the BA Certification Process, IT/System Modifications—Operations, IT/System Modifications—Compliance, Staffing to support BA Operations, and Hardware (interchange meter) installation. We discuss elsewhere in this Feasibility Study the necessary steps in each of these critical areas, and the person-hour time estimates associated with each. This timeline assumes use of internal resources only who are committed to the various work-streams as indicated, without the need for third-party bidding, selection and contracting processes.

With respect to staffing, BHE may choose to add the BA System Operations (SysOps) function to existing control center responsibilities on a shared resource basis or set up an independent BA SysOps desk as a stand-alone resource. As discussed elsewhere in this Feasibility Study, there are compliance, governance and expense considerations. From a purely timeline perspective, training existing SysOps staff is the quickest option. We have observed experienced, savvy system operators complete the requisite NERC training/certification within 3 months, at a cost of approximately $3,000 per employee for on-line training. Incremental OATI (E-tagging) and EMS functionality will take less training time, in our view, and are most efficiently accomplished once IT/Systems modifications are nearing completion. Taken together, this defines our minimum 6-month staffing estimate.

To establish the BA desk as a non-shared resource would entail either re-assigning or hiring 5 real time operators with requisite desk experience. We indicate approximately 12 months to satisfactorily complete that process under the assumption that BHE must hire outside and can tap into the WECC-wide talent pool to fill these roles without undue difficulty. We do not recommend or consider the time necessary to train personnel lacking SysOps experience to fill the BA desk roles.

We understand BHE is in the process of installing AGC equipment and related hardware in certain natural gas units of the generating fleet. We have not included the time necessary to complete this important element in the timeline below.

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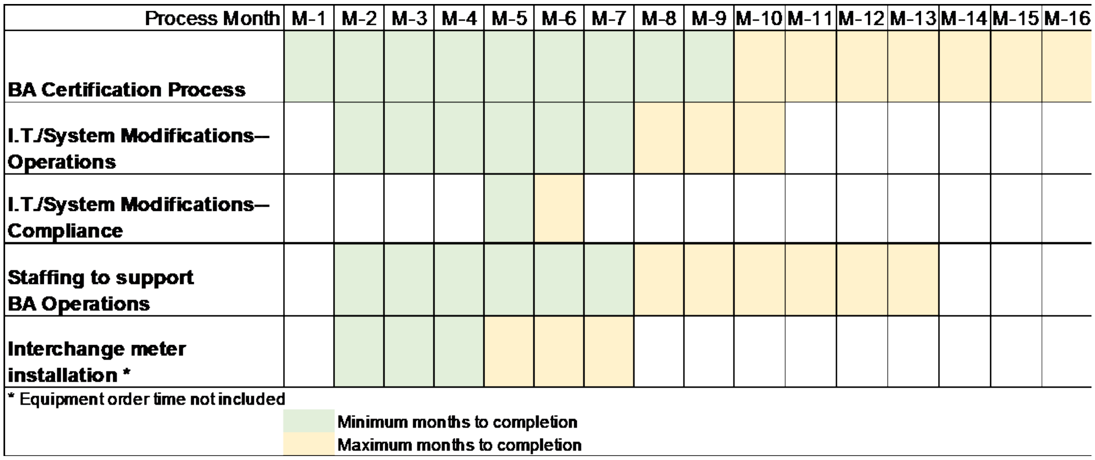

Figure 15: BA Certification/Set-Up Timeline

One-time BA Certification/Set-Up Burden/Expense Estimate

Table 23 below details our estimated $455k to $710k one-time expense BHE will incur to become certified and properly set-up from a systems and personnel perspective as a BA. We make the following assumptions in our assessment:

- BHE uses staff rather than outside consultants to accomplish the work. FTE salary and burden estimates are as indicated.
- BHE's systems are sufficiently robust to handle the additional requirements that BA operations will entail without substantial vendor supplied software upgrades.
- BHE's systems will require substantial modeling and modification, all of which can be accomplished in-house.
- Certification Staffing Cost follows from the recommended temporary staffing levels discussed elsewhere in the Feasibility Study, expenses at FTE rates. We have not factored staff time to achieve certification (if needed) into these figures.
- Meter installation assumes 8 revenue quality meters must be installed at interchange points with neighboring BAs.
- We have assumed that with respect to the incremental cost of telemetry/telecoms, no further upgrades would be needed to meet NERC requirements.
- Given the AGC installations underway within the BHE fleet, we have considered the incremental generator control cost to meet NERC standards to be zero.
- NERC/WECC Certification includes a site visit inspection resulting in follow-up action items. The follow-up burden is not included in this estimate.
- Existence of a backup control center is assumed—no incremental cost has been assigned.
- BHE already meets NERC Critical Infrastructure Protection standards that would apply as a BA; no incremental CIP costs are assumed.

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Certification and Set-up Burden/Expense Estimate

Item	low burden (hrs)	high burden (hrs)	low cost ($) *	high cost ($) *
Certification Application Cost				
Certification Review Preparation	1280	2560	94,769	189,538
Certification Review Site Visit	80	120	6,551	9,827
Site Visit--follow-up, remedial action **			-	-
EMS/Accounting/Compliance System Set-up ***				
OSI Monarch EMS modification	380	570	31,971	47,957
Inadvertent Energy Account system set-up	420	630	35,337	53,005
RC and TOP-003 system set-up	200	300	15,817	23,726
Compliance reporting automation	80	120	6,731	10,096
Certification Staffing Cost (@ full FTE rates)	burden (# FTE)	- burden (# FTE)		
BA Certification Preparation (RSAWs)	0.5	0.75	77,000	115,500
BA Policies/Procedures Prep	0.5	0.75	77,000	115,500
BA Training Development/Delivery	0.33	0.5	51,333	77,000
Other				
Interchange meter installation ****	256	384	41,231	49,846
ACE Diversity Interchange set-up fee			18,000	18,000
OATI WebTrans and E-Tag Approval Authority		*subscription cost not included*		
Total up-front Certification and Set-up Expense			455,700	710,000

* Assumes performance in-house at full FTE burden / 2,080 FTE hours per year
** Situationally dependent--expense not included
*** Assumes modifications to existing IT/EMS/Telecom systems; no new systems purchase
**** Assumes $3,000/meter equipment cost

Table 25: BHE BA certification and set-up cost estimate

On-going BA Overhead Burden/Expense Estimate

Table 24 below details our estimated $1.5M to $1.9M annual overhead expense that BHE will incur to operate as a BA discussed elsewhere in this Feasibility Study. We make the following assumptions in our assessment:

- Internal staff expense is charged at full FTE cost burden. An hourly FTE rate is imputed as indicated. Recommended staffing levels are discussed elsewhere in this Feasibility Study.
- A significant expense item follows from BHE's decision whether to use a dedicated resource or shared resource approach to fulfill the BA SysOps function. The requirement for 24-hr BA desk functionality means this decision weighs heavily on the on-going running costs BHE will incur as a BA.
- The energy accounting and RC/TOP systems maintenance burden shown is incremental to existing system maintenance requirements.
- We estimate that one FTE equivalent EMS Engineer will be required to maintain incremental EMS system functionality per BA certification requirements. This is

heavily dependent on the robustness of BHE's current OSI/Monarch system and may prove conservative.

On-going Staff, Systems Burden/Expense Estimate

Item	Y-1	Y-2	Y-3	Y-4	Y-5
BA Permanent Staffing Cost (full FTE rate)					
BA Desk Manager	$ 203,000	$ 207,060	$ 211,201	$ 215,425	$ 219,734
BA Compliance Coordinator	$ 154,000	$ 157,080	$ 160,222	$ 163,426	$ 166,695
BA Training Coordinator	$ 154,000	$ 157,080	$ 160,222	$ 163,426	$ 166,695
EMS Systems Engineer	$ 175,000	$ 178,500	$ 182,070	$ 185,711	$ 189,426
Inadvertent Energy Analyst	$ 119,000	$ 121,380	$ 123,808	$ 126,284	$ 128,809
NERC Cert. Operators (dedicated)	$ 700,000	$ 714,000	$ 728,280	$ 742,846	$ 757,703
NERC Certified Operators (shared)	$ 350,000	$ 357,000	$ 364,140	$ 371,423	$ 378,851
BA related System Maintenance (hourly rate *)					
Inadv. Energy Acctg system maintenance	$ 22,716	$ 23,171	$ 23,634	$ 24,107	$ 24,589
RC and TOP-003 system maintenance	$ 4,207	$ 4,291	$ 4,377	$ 4,464	$ 4,554
NERC/WECC Compliance					
BA Compliance Reporting	$ 73,298	$ 74,764	$ 76,259	$ 77,785	$ 79,340
NERC 3-yr Audit Preparation, Conduct			$ 15,406		
Administration					
NWPP admin fee	$ 100,000	$ 102,000	$ 104,040	$ 106,121	$ 108,243
ACE Diversity Interchange admin fee	$ 18,000	$ 18,360	$ 18,727	$ 19,102	$ 19,484
Inadvertent Energy Accounting	$ 10,298	$ 10,504	$ 10,714	$ 10,928	$ 11,147
Projected Annual Overhead (shared resource)	$ 1,383,500	$ 1,411,200	$ 1,454,800	$ 1,468,200	$ 1,497,600
Projected Annual Overhead (dedicated resource)	$ 1,733,500	$ 1,768,200	$ 1,819,000	$ 1,839,600	$ 1,876,400

* Assumes performance in-house at full FTE burden / 2,080 FTE hours per year

Table 26: BA Staff, Systems, Admin projected annual expense

Not surprisingly, the staffing cost is the significant non-energy consideration for BHE in setting up a BA. We are treating the NERC Certified System Operators as incremental cost to the status quo—either on a shared resource basis at 50% cost allocation (assuming 5 FTEs necessary to staff 24-hour capability), or a full resource basis at 100% cost allocation. Given its impact on overall running cost, this warrants internal analysis, in our view, to identify the extent to which existing System Operations desks may have the resource bandwidth to add BA responsibility. If that proves to be the case, then the NERC Operator line items in Table 24 above should be adjusted accordingly, with material impact on the cost comparisons presented below.

Cost Comparison: WAPA, BHE, PACE

Table 25 and 26 below compare the three scenarios, WAPA as BA, BHE as BA and PACE as BA. Table 25 represents the low-cost scenario, while Table 26 represents the high cost scenario. In the low-cost scenario, the BA Desk is a shared resource, with ½ of the cost allocated to the BA function. The BA Services cost for both WAPA and PACE, given the assumptions discussed in the Feasibility Study, are surprisingly close. We do not include BHE's up-front/start-up cost from Table 23, nor do we include PACE switching/configuration change costs (if any) below.

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Balancing Authority Operating Cost Comparison--Low Cost Scenario			
	WAPA as BA	BHE as BA	PACE as BA
Scheduling, System Control, and Dispatch Service	$ 316,416	incl below	$ 682,021
Reactive Supply, Voltage Control from Gen. or Other	$ 213,551	$ 213,551	$ 213,551
Regulation	$ 2,008,546	incl in imbal	$ 1,990,735
Frequency Response Service	incl in reg	$ 72,000	incl in reg
Imbalance/Inadv. Inter. (96% imbalance coverage)	$ 406,248	$ 3,504,114	$ (514,386)
Reserves	$ 597,000	$ 597,000	$ 729,000
BA Desk Staffing	-	$ 553,000	-
Compliance/Training Staffing	-	$ 308,000	-
IT Staffing/Systems	-	$ 201,920	-
Reporting/Admin/Other	-	$ 320,600	-
Totals	$ 3,541,761	$ 5,770,185	$ 3,100,921

Table 27: BA Services itemized annual cost comparison, BHE Low Cost Scenario

For BHE as BA, the Scheduling, System Control and Dispatch Service expense item is subsumed in the staffing and systems cost line items, while the Regulation line item is subsumed in the Imbalance/Inadvertent Interchange costs. With respect to Imbalance/Inadvertent Interchange, we assume in the Low BHE Scenario that system needs are met with resources as discussed in the 96% imbalance coverage scenario.

Table 26 reflects the High BHE Scenario which indicates a substantial expense burden for BHE as BA relative to both the WAPA as BA and PACE as BA alternatives. Two elements contribute most significantly when compared to the Low BHE Scenario: staff cost and Imbalance. We assume here that system needs are met with resources as discussed in our 98% imbalance coverage scenario. We include full cost and allocation of incrementally adding a BA Desk. This scenario also includes the high cost estimate for Frequency Response. The WAPA and BHE BA Reserves charges reflect our more conservative calculation of the opportunity cost to meeting the NWPP RSG reserve requirement. As in the Low BHE Scenario, we include neither BHE up-front costs nor PACE switching costs in the below results.

Balancing Authority Operating Cost Comparison--High Cost Scenario			
	WAPA as BA	BHE as BA	PACE as BA
Scheduling, System Control, and Dispatch Service	$ 316,416	incl below	$ 682,021
Reactive Supply, Voltage Control from Gen. or Other	$ 213,551	$ 213,551	$ 213,551
Regulation	$ 2,008,546	incl in imbal	$ 2,101,199
Frequency Response Service	incl in reg	$ 600,000	incl in reg
Imbalance/Inadv. Inter. (99% imbalance coverage)	$ 406,248	$ 5,325,368	$ (514,386)
Reserves	$ 2,334,300	$ 2,334,300	$ 729,000
BA Desk Staffing	-	$ 903,000	-
Compliance/Training Staffing	-	$ 308,000	-
IT Staffing/Systems	-	$ 201,920	-
Reporting/Admin/Other	-	$ 320,600	-
Totals	$ 5,279,061	$ 10,206,739	$ 3,211,385

Table 28: BA Services itemized annual cost comparison, BHE High Cost Scenario

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It is important to note that the individual line items in both the Low BHE and High BHE Scenarios are independent. We have grouped all line item low cost alternative in Table 25 and all line item high alternatives in Table 26. For this reason, the resultant totals should be viewed as bracketing the expected WAPA, BHE and PACE BA costs.

As a final comparative note, the summaries above assume an "all or nothing" approach to BA Service provision. Our estimate of the very substantial difference in Imbalance/ Inadvertent Interchange charges that BHE as BA will incur by fully incorporating a relatively large wind portfolio is detailed in Table 27. We believe it is worth exploring whether WAPA or other neighboring BAs may be able to firm/shape these wind resources more economically.

	Deoptimzation due to full wind integration	Deoptimization without wind integration	Implied annual cost delta
Imbalance/Inadv. Inter. (96% imbalance coverage)	$ 3,504,114	$ 665,289	$ 2,838,826
Imbalance/Inadv. Inter. (99% imbalance coverage)	$ 5,325,368	$ 849,990	$ 4,475,377

Table 29: Estimated annual cost of wind integration to BHE BA

Rate Impact Relative Economics

Table 28 and Table 29 summarize the potential year 1 economic impact of BHE establishing its own BA or turning to PACE as third-party BAA on overall load tariffs, assuming Evaluation Period load levels. WAPA BA cost is assumed baseline, with BHE BA and PACE BA measured relative to that baseline in both scenarios. We have assumed no amortization of set-up costs.

	Overall tariff impact--Low Cost Scenario		
	WAPA as BA	**BHE as BA**	**PACE as BA**
Set-up Costs	$0	$1,383,500	$0
Operating Cost Year 1	$3,541,761	$5,770,185	$3,100,921
Total Year 1, no amortization	$3,541,761	$7,153,685	$3,100,921
Incremental Rate Impact across load	baseline	$0.75	-$0.09

Table 30: Potential rate impact relative to status quo, low cost scenario

	Overall tariff impact--High Cost Scenario		
	WAPA as BA	**BHE as BA**	**PACE as BA**
Set-up Costs	$0	$1,733,500	$0
Operating Cost Year 1	$5,279,061	$10,206,739	$3,211,385
Total Year 1, no amortization	$5,279,061	$11,940,239	$3,211,385
Incremental Rate Impact across load	baseline	$1.38	-$0.43

Table 31: Potential rate impact relative to status quo, high cost scenario

In both low and high scenarios summarized, the BHE BA scenario reflects a relative burden to ratepayers while the PACE BA represents a relative benefit, to ratepayers.

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Summary of Findings

Based on the data and information provided by BHE, the analysis conducted per the analysis plan agreed with BHE, and the assumptions and recommendations set forth in this Feasibility Study, we conclude:

1. It is feasible for Black Hills Energy to break off from the Western Area Power Administration and become its own Balancing Authority Area. BHE's collection of resources, experience operating as a sub-BA, initiative to equip plants with AGC, and familiarity with system operations indicate good overall positioning for taking on this responsibility.
2. We feel confident that BHE can satisfy the balancing standards required for BA compliance, including regulation.
3. From a cost/benefit perspective, we conclude that BHE is likely to incur somewhat greater cost establishing its own BA compared to the current WAPA cost or possible PACE cost. While certain economic scenarios in this Feasibility Study support this consideration, we caution that more detailed analysis, as highlighted within the body of this Feasibility Study, should be undertaken before a definitive conclusion can be reached.
4. It should be noted that becoming a standalone BA would allow BHE to participate in the CAISO EIM market and the value of these potential energy sales have not been included in our analysis.
5. The following prudent considerations should be taken by BHE as BHE contemplate taking next steps with respect to establishing a BA:
    - The assumption that four second data, when gathered and analyzed, will refine the cost/benefit conclusions reached in this Feasibility Study with respect to regulation service.
    - The extent to which generating units can be equipped to respond to frequency events.
    - This broadened due diligence should include discussions with WAPA and PacifiCorp as neighboring BAs in order to gauge their respective levels of cooperation and mutual interest. As highlighted in the Feasibility Study, cooperative efforts with PACE to re-configure telemetry, to reallocate EMS logic, and possibly to explore integrating wind generation output into less correlated/larger intermittent resource portfolios could materially impact BHE BA comparative economics both positively and negatively.
    - The steps necessary to ensure BHE personnel are ready to manage a NERC compliant portfolio, including daily setup of resources needed for compliance.

Conclusion

Black Hills Energy is well positioned to take on the Balancing Authority function within WECC. The organization is well staffed and with its current NERC functional registrations (TOP, TO, TSP, TP, RP, DP, PA / PC), the Balancing Authority function is the next logical step. The BA certification preparation will require focused staff to complete required systems updates, develop procedures, complete RSAWs, and perform Balancing Authority training. Black Hills currently has two individuals in the compliance role with one of those splitting time between compliance and training. Given the amount of work and time to prepare for the certification audit, it is suggested that adding at least one FTE be considered.

Because Black Hills has two control centers, one focusing on transmission and distribution operations and the other focusing on generation dispatch and load forecasting, the organization could choose to host the BA operations desk in either control center. Black Hills could choose to "split" current staff to manage the BA operations desk, however, industry standard is generally to have a separate desk focused on Balancing Authority Operations. Because Black Hills has a well-staffed generation control center, it may be attractive to use that staff to both operate the BA function and the generation dispatch function, however, the two roles have very different focus. The generation dispatch role is focused on meeting load requirements in the most efficient manner possible, while the balancing authority role must focus on maintaining compliance with NERC/WECC standards. These two roles can certainly be combined; however, the different focuses must be considered when reviewing staffing and training needs. Black Hills should also consider adding a management role to oversee and coordinate the BA operations desk.

Participating in the NWPP will also require additional time from Black Hills staff to attend quarterly meetings and follow NWPP OC and RSG requirements and changes. Black Hills should consider adding 1 FTE to manage and participate in required committee meetings within NWPP and WECC. Becoming a Balancing Authority will also require Black Hills to stand up an After-the-Fact Inadvertent Energy accounting function to perform daily and monthly inadvertent energy checkouts and reporting. This role will also have committee participation requirements with the WECC ISAS committee to ensure the organization maintains awareness of any changes in NERC/WECC rules regarding inadvertent energy accounting.

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Appendix A-NERC BA Footprint Change Tasks Document

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Notification Timeline:

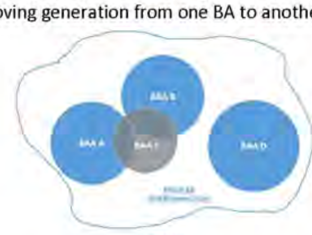
A BA that will be experiencing changes in footprint should notify all the applicable groups no less than sixty (60) calendar days prior to the effective implementation date. Proper coordination to transfer responsibilities is essential for the BAs to operate and meet their obligations.

Scope

The following are the more common changes that occur to BAs, especially to those that operate in multi BA Interconnections (e.g., Western Interconnection (WI) and Eastern Interconnection (EI)):

1. **Total Merge** – at least two BAAs participate. One or more remain as registered BA(s), while the other(s) proceed to deregister from NERC. See Diagram 1 and Diagram 5.

2. **Partial Merge** – A portion of generation and/or load is moved from one or more existing BAA(s) to one or more new or existing BAA(s). Transferring BA remains registered with NERC. This may include Pseudo Ties moving generation from one BA to another. See Diagram 2.



3. **New BA** – It did not exist previously (i.e., recently registered and certified). See Diagram 3.

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a. New generation and/or load to the Interconnection forming a new BA. See Diagram 4.

b. Existing generation and/or load operating in the Interconnection forming a new BA. A mix of new and existing generation and/or load in the Interconnection forming a new BA.

4. **Deregistered BA** – A BA planning to discontinue operations transferring generation and/or load into receiving BAA(s).

5. **Receiving BA (Successor)** - BA changes name or turns over responsibility to another entity.

BA footprint changes between interconnections are not in scope.

Process Steps

I. NERC Certification Process
Each NERC RE[1] has registration information posted on its website regarding how to start the NERC certification process. The certification process may take up to nine (9) months to complete. Refer to Appendix 5A – Organization Registration and Certification Manual (Section 500 of the Rules of Procedures) – **New BA Task**

II. Obtain BA ID
Obtain BA ID from the North American Energy Standards Board (NAESB)[2] Electric Industry Registry (EIR) – 4-character maximum label – **New BA Task**

III. BA Map Bubble Diagram
Add new BA, or updated BAA footprint, to the NERC BAs bubble diagram – **NERC RS Task**

III. Model Revision
Notify groups or entities responsible for making update(s) to power flow representations applicable to their area.

- Interchange Distribution Calculator (IDC)[3]– Eastern Interconnection
- Enhanced Curtailment Calculator (ECC)[4] – Western Interconnection,
- Multi Regional Modeling Working Group Model (MMWG) – Eastern Interconnection

– **EIDSN, ECCTF, MMGW, BA Task**

[1] Regional Entity Registration and Certification information: FRCC | MRO | NPCC | RF | SERC | SPP RE | Texas RE | WECC
[2] The EIR is maintained by the North American Energy Standards Board
[3] The IDC is maintained by the Eastern Interconnection Data Sharing Network, Inc.
[4] The ECC is maintained by PEAK Reliability RC

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IV. Inadvertent Interchange
For merged BAs, the BA that is deregistering needs to transfer its Inadvertent balance to the acquiring BA. For BAs that are splitting or transferring, they may allocate Inadvertent Interchanges as the parties deem appropriate, but the net balance between the remaining BAs must remain the same **– Deregistering BA, Receiving BA, and Regional Inadvertent Survey Contact Task**

V. Submit FERC 714 Data Schedule II Part III or Similar
From BAs experiencing changes in footprint will complete and submit a BA to BA General 714 data submittal form (or its successor) to NERC RS staff support. The FERC 714 data (or similar) will apply for the two years prior and year to date - once available. Data must be provided separate by calendar year (2 complete and 1 partial year) – **Transferring and Receiving BA Task**

IV. Frequency Response Obligation (FRO)
Although intra-year reallocation of FRO between receiving and transferring BA is not in scope in the current BAL-003-1 NERC Reliability Standard under enforcement, this reference document shows the two options BAs experiencing changes in footprint may agree to follow.

Option 1 – No change in FRO Apply – In this case the transferring BA retains any primary frequency response measure (FRM) contributed by the assets being transferred through the end of the operating year. The receiving BA, on the other hand, will not use any primary FRM contributed by the assets being transferred towards its FRO. Transferring and receiving BA(s) should follow the **No Change in FRO Apply** process below.

Option 2 – Change in FRO Apply – The other option for both the transferring and receiving BA(s) is for both to agree to reallocate FRO retroactive to the beginning of BAL-003 operating year. Transferring and receiving BA(s) should follow the **Change in FRO Apply** process below.

1. **No Change in FRO Apply**
   As described in Option 1 above, the BA(s) will retain both its originally allocated FRO and any primary FRM contributed by the assets being transferred. In this case, the BAs experiencing changes in footprint are responsible for:
   a. Documenting and reporting changes in footprint to NERC through its (their) Regional Entity (RE)
   b. Communicating to NERC through the RE the agreements between BA(s), or lack of, that will indicate or result in retention of both FRO and FRM by transferring BA through the end of the operating year; especially when the assets in transition are forming a new BA where the new BA will not have an FRO allocated until the following operating year.
2. **Change in FRO Apply**
   If any agreements or exemptions as described on Option 2 above apply, then a reallocation of FRO, ***retroactive to the beginning of the operating year***, will be calculated and officially communicated by NERC to the BAs experiencing changes in footprint. In this case, the transferring BA(s) and receiving BA(s) will be responsible for the following:

a. Communicating agreements between BAs that will result in transferring BA(s) subtracting any primary FRM contributed by those assets from its(their) FRS Form 1 and FRS Form 2 – **Both transferring and receiving BA(s) Task**

b. Transferring the data subtracted from FRS Form 1 and FRS Form 2 to the receiving BA(s) – Transferring BA Task

c. Completing FRS Form 1 and FRS Form 2 from the data received from the Transferring BA for submission to NERC at the end of the operating year – **Receiving BA Task**

Scenarios for when Change in FRO Apply
The following hypothetical scenarios will guide the involved parties on the necessary steps to be completed when retroactive reallocation of FRO applies. The changes may be due to total merges, partial merges or creation of new BA(s).

1. **Total Merge – At Least Two BA Involved**
At least one BA remains a registered BA while the other(s) will deregister.

In this example (see Diagram 1), BA C merges to BA A. Therefore, BA A becomes the receiving BA while BA C becomes the transferring (deregistering) BA. Here are the steps that both BA A and BA C should follow:

a. BA A, receiving generating assets and/or load from the transferring (deregistering) BA C, will report and document taking over BA C's existing FRO retroactive to the beginning of the BAL-003 Operating Year – **Receiving BA A Task**

b. BA A should obtain *FERC 714 data Schedule II Part III* (or similar) from BA C to complete and submit a *BA to BA General 714 data submittal form* (or its successor) to NERC RS support staff – **Deregistering BA C and Receiving BA A Task**

c. NERC staff, once it has received the BA to BA General 714 data submittal form(s) (or its successor) from BA A and BA C, will then calculate FRO reallocations for the current operating year and upcoming operating year (if already calculated or in process) – **NERC Staff Task**

d. The NERC staff supporting the NERC RS will document the BA FRO reallocation for the current operating year and for the upcoming operating year (if applicable). The official document will be posted in the Balancing Authority Submittal Site (BASS) or its successor – **NERC Staff Task**

2. **Partial Merge - BA Footprint Changes Between At Least Two Existing BAs**
A partial merge occurs when at least one BA merges with at least one other BA. All BAs remain registered. Only a portion of generation and/or load gets transferred to at least one other BA.

In this example, BA C transfers a portion of its generation and/or load to BA A and BA B (see Diagram 2).

The following are the steps that BA A, BA B and BA C should follow:

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a. BA A and BA B, receiving generating assets and/or load from the transferring BA C, will report and document taking over the applicable calculated portion of BA C's FRO retroactive to the beginning of the BAL-003 Operating Year – **Receiving BA A and BA B Task**

b. BA A and BA B, receiving generating assets and/or load into their respective BAA from BA C, will obtain all applicable *FERC 714 Schedule II Part III* data (or similar) from BA C to complete and submit a *BA to BA General 714 data submittal form* (or its successor) to NERC for FRO reallocation purposes – **Receiving BA A and BA B Task**

c. BA C will also submit a *BA to BA General 714 data submittal form* with the net generation and/or and NEL that will remain in its BAA – **Transferring BA C Task**

d. Once all BA to BA General 714 data submittal forms (or its successor) are received by NERC from the BAs involved in the partial merge, NERC will initiate the reallocation of FRO for the operating year in enforcement – **NERC Staff Task**

e. NERC will update the *BA FRO Allocation* report for the BAL-003 operating year in enforcement and reissue making the transfer of FRO official. The official document will be posted in NERC BASS (or its successor) – **NERC Staff Task**

3. **Partial Merge - BA Footprint Changes Between Existing BA(s) and New BA(s) –**
Like the previous scenario, a partial merge occurs when at least one BA merges with at least one other BA. In this case, the BA receiving generation and/or load is a newly registered BA (see Diagram 3).

For instance, the source data for the reallocation of the new BA's FRO will be from a subset of transferring BA D's *FERC 714 Schedule II Part III (or similar)*, applicable to the assets and/or load being transferred. Once again, FERC 714 data will apply for the two years prior up until the last day the transferred generating assets and/or load were within BA D's BAA. Data must be provided separate by calendar year (2 complete and 1 partial year).

Here are the steps that BA D and BA E should follow:

a. The existing BA D is transferring generation and/or load to the newly created BA E. Therefore, BA E will obtain all applicable portion of its *FERC 714 Schedule II Part III* data (or similar) from BA D to complete a *BA to BA General 714 data submittal form* (or its successor) for submittal to NERC RS support staff. Similarly, BA D will submit a *BA to BA General 714 data submittal form* with net generation and/or load that will remain in its BAA – **Transferring BA D and Receiving BA E Task**

b. NERC Staff, once it has received the BA to BA General 714 data submittal form(s) (or its successor) from the BAs involved in the partial merge, will then calculate FRO reallocations for both the new BA E and transferring BA D – **NERC Staff Task**

c. NERC will update the *BA FRO Allocation* report for the BAL-003 operating year in enforcement and reissue making the transfer of FRO official. The official document will be posted in NERC BASS (or its successor) – **NERC Staff Task**

New Assets Forming a New BA (Gen Only BA or Load Only BA) - No Initial FRO allocated
If new generation and/or load intends to interconnect to the BES and form a new BAA, none of the above scenarios apply. In this case, the only data source for the allocation of the new BA's FRO comes from non-BA quality data. Instead, the source for the calculation of FRO will come either from testing data, transmission planning studies, contracts, or generation and/or load forecast from the new BA F's registration (see Diagram 4).

These are the steps that BA F and other applicable entities may follow:

1. Estimate net generation and/or load from testing and/or contracts to calculate an estimated and potentially non-enforceable FRO. The estimated FRO will be in place for BA F to operate with a baseline while BA quality data is collected and validated for the following two BAL-003 operating years – **NERC Staff Task**
2. Estimated generation or load will be reviewed and approved by NERC staff and the Regional Entity as a best estimate to allocate an estimated FRO - **Regional Entity and NERC Staff Task**
3. NERC staff may update the *BA FRO Allocation* report to add the new BA and reissue. Effective date for implementation should not change since the FRO is just estimated for the new BA. Therefore, there is no need for altering the previously allocated and published FRO for not affected BAs in the interconnection. The official document may be posted in NERC BASS (or its successor) – **NERC Staff Task**

V. Calculation and Reallocation of Frequency Bias Setting (FBS) and L_{10}
BAs may do a risk analysis on the potential impact of changes to their FBS. Especially, any impact to key BA operating reliability metrics such as CPS1, BAAL and ATEC (WI Only). Once completed, the BA may decide to either:

1. Leave their elected FBS "as is" for the remainder of the BAL-003 operating year. Mainly, if the amount of generation and/or load being transferred does not represent a significant impact to the reliable operation of their BAA. Especially if one or more of the BAs involved in the transfer is using Variable Non-Linear FBS.
   a. BA(s) using Variable Non-Linear FBS should adjust generation and/or load assets transferred from/to receiving/transferring BA(s) from automatic generation control (AGC) on the Energy Management System (EMS).

   Note: Once the adjustments are made, the EMS will start auto calculating all the input variables for the calculation of Variable Non-Linear FBS. Refer to Attachment D for more information.
2. Recalculate a new FBS by completing prior year's FRS Form 2 and FRS Form 1 adding/removing the data from generation and/or load being transferred (BA quality data).

   Note: This methodology only applies to BA(s) using Fixed-Linear FBS.
3. Calculate the lowest absolute fixed FBS (based on the interconnection's peak demand/generation from FERC 714 data or similar for the corresponding generation and/or load being transferred) and add/subtract from the BA's elected FBS as posted on NERC BASS.

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Note: This addition/subtraction methodology applies to BA(s) using either Fixed-Linear or Variable-Non-Linear FBS.

4. Transfer a mutually agreed portion of the transferring BA's FBS to the receiving BA by either:
   a. Calculating the actual primary frequency response median from the assets being transferred, or
   b. Calculate the absolute lowest absolute fixed frequency bias setting (based on the interconnection's peak demand/generation from the corresponding generation and/or load being transferred).
   c. Agree on an estimated percentage of net generation and/or load from BA C's *FERC 714 Schedule II Part III* data being relocated into each Receiving BA's BAA. Then use the estimated percentage to reallocate BA C's elected FBS to each Receiving BA.

   Note: This addition/subtraction methodology applies to BA(s) using either Fixed-Linear or Variable-Non-Linear FBS. The intra-year reallocation of FBS should not alter the interconnection's allocated FBS. In other words, the reallocation should not affect other BAs previously elected FBS and allocated L_{10}.

Below are the same or similar scenarios to the ones used to illustrate FRO reallocation in Section V above. The BA(s) may follow these steps when experiencing a total merge, partial merge or the creation of a new BA.

1. **Total Merge Methodology –Two BAs Involved**
   a. In this scenario, a total merge occurs between BA A and BA C. BA C is the receiving BA while BA C is the transferring/deregistering BA (see Diagram 1 below). The methodology in this case is simple. Deregistering BA C's elected FBS may be reallocated in its entirety to BA A for the remainder of BAL-003 operating year. This methodology applies to BAs using either Fixed-Linear or Variable-Non-Linear FBS **– Deregistering BA and NERC Staff Task**
   b. BA A should obtain FERC 714 data Schedule II Part III (or similar) from BA C to complete and submit a BA to BA General 714 data submittal form (or its successor) to NERC RS support staff **– Deregistering BA C and Receiving BA A Task**

      Note: The FERC 714 data (or similar) from BA C should consist of the last two annual filings with FERC plus year-to-date monthly generation and/or load not yet filed. The data will be used by NERC staff to calculate BA A's minimum FBS for the next two years.

2. **Total Merge Methodology – At Least Three BAs Involved**
   If a total merge occurs between three or more BAs where two or more are receiving and one is deregistering (see diagram 5), the following steps should be followed:
   a. Both BA A and BA B should obtain, from deregistering BA C, the last two *FERC 714 Schedule II Part III* data submissions (or similar) plus any year-to-date monthly net generation and/or load. The data obtained will be required to complete a *BA to BA General 714 data submittal form* (or its successor) for submittal to NERC RS support staff **– Receiving BA(s) Task**

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Important: Dynamic transfers where BA C was the source BA claimed by sinking BA(s) as net generation per FERC 714 reporting instructions, may be included by BA C as native generation for an accurate reallocation of Frequency Bias Setting (FBS) to BA A and BA B.

b. Update the FERC 714 data for the applicable BA(s) and recalculate the absolute minimum FBS allocation for receiving BA A and BA B – **NERC Staff Task**

Both BA A and BA B may decide to either follow steps c through d (BA using Fixed Linear FBS) or just step f (BA using Fixed Linear or Variable Non-Linear FBS) as described below:

c. Resubmit new FRS Form 2 (or its successor) for each one of the events posted on prior year's BAL-003 FRS Form 1 (or its successor). This time incorporating actual frequency response from the generation and/or load received from BA C - **Receiving BA(s) Task (using Fixed Linear FBS)**

d. BA A and BA B will select the Form 1 Summary Data worksheet on the FRS Form 2 (or its successor), to then copy and then paste the frequency response data calculated for each event to the BA Form 2 Event Data worksheet on their respective FRS Form 1 (or its successor) – **Receiving BA(s) Task (using Fixed Linear FBS)**

e. Once primary frequency response data has been imported to the FRS Form 1 (or its successor) for each event, the following values should be calculated automatically for BA A and BA B in the worksheet:

   i. New lowest fixed FBS based on 100% of FRM Median and the BA's highest fixed FBS based on 125% of FRM Median

   ii. BA minimum absolute fixed FBS based on interconnections non-coincident peak demand/generation

   iii. Compare the product of step i. and ii. If the product of step i. is greater than the product of step ii., for either BA A or BA B, then the BA will be allowed to select their desired FBS (between 100% of FRM and 125% of FRM) if not currently using Variable Non-Linear FBS.

   iv. If, on the contrary, the product of step i. is less than the product of step ii., then BA A and/or BA B will be allocated an absolute minimum fixed frequency bias setting based on interconnection's peak demand/generation by NERC, if not currently using Variable Non-Linear FBS.

f. Agree on an estimated percentage of net generation and/or load from BA C's *FERC 714 Schedule II Part III* data being relocated into each Receiving BA's BAA. Then use the estimated percentage to reallocate BA C's elected FBS to each Receiving BA. For instance, if 70% and 30% of the generation and/or load is transferred from BA C to BA A and BA B respectively, the FBS to be reallocated should equal the existing elected BA C's FBS times .7 to BA A while the rest (i.e., BA C's FBS times .3) will go to BA B – **Receiving BA(s) Task (using either Fixed Linear or Variable Non-Linear FBS)**

g. Update the Frequency Bias Setting and L_{10} Values report for the applicable operating year and reissue with an effective date (if necessary). The official document will reside in the NERC BASS site – **NERC Staff Task**

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3. **Partial Merge Methodology - BA Footprint Change Between At Least Three Existing BAs**
This scenario is like scenario 2, which is represented in Diagram 5 above. The only difference is that all BAs remain registered BAs and only a partial merge occurs from BA C to BA A and BA B. See Diagram 2. Therefore, all steps in scenario 2 may be followed by all BAs to calculate the new FBS.

4. **Partial Merge - BA Footprint Changes Between Existing BA(s) and New BA(s)**
This scenario is like scenarios 2 and 3 above. In this instance, transferring BA D remains a registered BA and BA E is the new registered BA. A partial merge occurs between BA D and BA E. BA E may be a generation and load BA, generation only BA or load only BA. See Diagram 3.

   All steps in scenario 2 may be followed by both BAs to calculate their new FBS. However, depending on the amount of generation and/or load being transferred to BA E, the transferring BA D (as mentioned in section VI above) may decide to either maintain the same FBS (option i.) or mutually agree to transfer a representative portion of its elected FBS to BA E (option iv.). If option iv. is agreed upon by both BAs, BA E will use the transferred FBS as its starting FBS for current and following year's BAL-003 operating year.

5. **New BA with New Generation and/or Load**
This scenario 5 is different than the aforementioned scenarios. In this case, new generation and/or load have been added to the interconnection and, instead of joining the BA operating in the area, an entity decides to form its own BA. See Diagram 4.

   These are the steps that may be followed by the new BA:

   a. If no BA quality data exist from new resources forming the new BA, then the new BA should use estimated annual net generation and/or load values from testing prior to commissioning and submit to NERC to allocate an initial FRO – **New BA and NERC Staff Task**
   b. Use the allocated FRO from NERC and calculate an initial FBS based on lowest absolute frequency bias setting based on interconnection's peak demand/generation. Submit to NERC for approval – **New BA Task**
   c. Update the Frequency Bias Setting and L10 Values report adding the new BA for the existing operating year and reissue and updated version with the effective date for implementation. The official document will reside in the NERC BASS site – **NERC Staff Task**

VII. Reliability Coordinator IROL Operating Procedure(s)
Update and communicate any new roles and responsibilities identified in the RC's IROL operating process as a result of changes in BA(s) footprint. The RC(s) and BA(s) experiencing changes in footprint are responsible for updating, communicating and training the receiving entities on the revised operating process which defines their new role(s) and responsibilities in the mitigation of IROL exceedances in the RC area. – **RC and Transferring BA Task**

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VIII. Reporting
Update BAL-003 BA listing on the Frequency Bias Setting and L10 Settings Report and update CERTS[5] reliability tools (e.g., Resource Adequacy) with elected BA FBS, FRO, and L_{10} – **NERC Staff Task**

IX. Update NERC BASS
Add new BA to the NERC BASS, identify BA's primary and secondary contacts and grant them access for periodic upload of CPS1, BAAL and BAL-003 data – **NERC Staff and New BA Task**

X. Support the ACE
Reporting application with real time ACE on ICCP link – **BA Task, RC Task, NERC Staff Task, and EPG Task**

XI. Obtain accounts for CERTS tools including the Inadvertent Interchange Accounting application
Add interfaces for adjacent BAs in Inadvertent tool and the NERC BASS for BAL-003 metrics and control performance reporting (CPS 1) – **New BA Task, NERC Staff Task**

XII. Obtain Services from a Reliability Coordinator (RC)
NERC Rules of Procedure Section 500, paragraph 1.4.2 require that all BAs be under the responsibility of an RC[6] - **New BA Task**

XIII. Coordination of Adjacent BAs and RC
Update the following as applicable:

- Reliability Plan (RC and Operating Reliability Subcommittee)
- NERC Certification and Registration
- Coordination on reporting for NERC Assessments and,
- Net Energy for Load (NEL) reporting to NERC for appropriate allocation of billing

– **NERC Staff and NERC Certification Task**

XV. Remove Access
Lock out from access to NERC reliability applications, as applicable – **NERC Staff Task**

[5] The Consortium Of Electric Reliability Technology Solutions (CERTS) maintains a suite of reliability tools for BAs to use
[6] NERC Rules of Procedure can be found at NERC.com

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ATTACHMENT A
PRIMARY INADVERTENT INTERCHANGE REALLOCATION WESTERN INTERCONNECTION ONLY

Purpose
This section of the document is created to provide BAs in the Western Interconnection with a recommended blueprint on how to mutually agree to manage the potential reallocation of Accumulated Primary Interchange between BAs.

I. Accumulated Primary Inadvertent Interchange (PII_{Accum})
We will use the same scenarios shown in section VI of this document to assist BAs in the calculation of new PII_{Accum} balances (On-Peak and Off-Peak), as well as PII_{Accum} limits. This section only applies to BAs in the Western Interconnection.

1. **Total Merge Scenario – Two BAs Involved**
   When a total merge occurs between two BAs, the PII_{Accum} balances (On/Off-Peak) and PII_{Accum} limits must get transferred in complete coordination and cooperation between the transferring BA, the receiving BA and the WECC Interchange Tool[7] (WIT) administrator. Meaning, the day of the month and the hour when the BA ceases operations must be coordinated, so that the final balances get properly transferred to the receiving BA in WIT (or its successor) on the exact date and hour-ending the merge becomes official.

Table 1 below shows the deregistering BA's (BA B) last hour-ending PII_{Accum} On-Peak balance, PII_{Accum} Off-Peak balance and PII_{Accum} limits before the merge, while Table 1A shows the algebraic sum of BA A's and BA B's adjusted PII_{Accum} On/Off-Peak balances (on Table 1) after the merge, to be carried and paid back by receiving BA A going forward, via Automatic Time Error Correction (ATEC).

BEFORE MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	-150	-120	200
B	250	140	300

Table 1

AFTER MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	100	20	500
B	0	0	0

Table 1A

In this case BA B's 250 MWh and 140 MWh of PII_{Accum} On-Peak and Off-Peak balances, respectively, get transferred by performing an algebraic sum to BA A's last hour-ending balances. BA B's PII limits (300 MWh) are also transferred to BA A's previous limit (200 MWh) effective the end of the month after the merge occurs.

[7] https://www.wit.oati.com/tes_wit/tes-login-new.wml

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2. **Total Merge Scenario – At Least Two BAs Involved**
   In this example, BA A and BA B will be absorbing a portion of generation and or load from the deregistering BA C. Refer to Diagram 5.

Table 2 below shows the deregistering BA C's before merge last hour-ending PII_{Accum} On-Peak balance, PII_{Accum} Off-Peak balance and PII limits. Once again, the day of the month and the hour when the BA ceases operations must be coordinated, so that the final balances get properly transferred to the receiving BA in WIT (or its successor) on the exact date and hour-ending the merge becomes official.

Table 2A below shows the algebraic sum of BA A's and BA B's adjusted PII_{Accum} On/Off-Peak balances (on Table 1) to be carried and paid back by receiving BA A and BA B going forward, via Automatic Time Error Correction (ATEC).

BEFORE MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	-150	-120	200
B	250	140	300
C	200	-100	500

Table 2

AFTER MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	100	-160	400
B	400	80	600
C	0	0	0

Table 2A

Here are the steps that needed to be completed by the BAs (deregistering and receiving) to come up with the after-merge hour-ending adjusted balances:

a. Calculate the amount of PII_{Accum} (On-Peak and Off-Peak) contributed by each individual asset being transferred to the receiving BA A and BA B – **Deregistering BA Task.**

b. Transfer the PII_{Accum} balances (On-Peak and Off-Peak) contributed by each individual asset transferred to their respective receiving BA A and BA B – **Deregistering BA Task.**

c. Identify the amount of generation or load that each asset contributed towards the calculation of prior calendar year's integrated hourly peak demand or generation – **Deregistering BA Task.**

d. Transfer generation and or load data from each individual asset to receiving BA A and BA B for future calculation of PII limits based on prior calendar year's integrated hourly peak demand or generation – **Deregistering BA.**

e. Update the newly adjusted PII_{Accum} balances and PII limits in WIT (or its successor) – **Receiving BAs and WIT Administrator.**

3. **Partial Merge Methodology - BA Footprint Change Between At Least Two Existing Bas**
   Like the total merge methodology in the previous example, this time BA A and BA B will be absorbing only a portion of generation and or load from transferring BA C, which will remain a registered BA. Refer to Diagram 2.

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Table 3 below shows the transferring BA C's before merge last hour-ending PII_{Accum} On-Peak balance, PII_{Accum} Off-Peak balance and PII limits. Once again, the day of the month and the hour when the BA ceases operations must be coordinated, so that the final balances get properly transferred to the receiving BA in WIT (or its successor) on the exact date and hour-ending the merge becomes official. Table 2A below shows the algebraic sum of BA A's and BA B's PII_{Accum} On/Off-Peak balances (on Table 1) to be carried and paid back by receiving BA A and BA B going forward, via Automatic Time Error Correction (ATEC).

BEFORE MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	-150	-120	200
B	250	140	300
C	760	-600	800

Table 3

AFTER MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	50	-170	400
B	350	40	500
C	460	-450	400

Table 3A

Here are the steps that needed to be completed by the BAs (deregistering and receiving) to come up with the after-merge hour-ending adjusted balances:

a. Calculate the amount of PII_{Accum} (On-Peak and Off-Peak) contributed by each individual asset being transferred to the receiving BA A and BA B – **Deregistering BA Task**

b. Transfer PII_{Accum} balances (On-Peak and Off-Peak) contributed by each individual asset transferred to their respective receiving BA A and BA B – **Deregistering BA Task**

c. Identify the amount of generation or load that each asset contributed towards the calculation of prior calendar year's integrated hourly peak demand or generation – **Deregistering BA Task**

d. Transfer generation and or load data from each individual asset to receiving BA A and BA B for future calculation of PII limits based on prior calendar year's integrated hourly peak demand or generation – **Deregistering BA**

e. Update the newly adjusted PII_{Accum} balances and PII limits in WIT (or its successor) – **Transferring BA, Receiving BAs and WIT Administrator**

If transferring or receiving BA's newly adjusted PII_{Accum} balances are greater than the recalculated PII Limits, the BA(s) may request the Regional Entity to maintain the previous PII limits before BAL-004-WECC -02 R1 becomes fully enforceable with the new PII limits. For instance, let's assume that BA C's newly adjusted PII_{Accum} balances On/Off Peak are 460 MWh and -450 MWh respectively. Also, the PII_{Accum} limits, because of the change, decreased by half from 800 MWh to 400 MWh (see Table 3A). BA C, therefore, based on the results from the after-merge adjustments, may opt for requesting a 90-day extension to

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continue using the previous PII_{Accum} limits while it works towards bringing its PII_{Accum} balances down – **Transferring BA, Receiving BA and Regional Entity Task.**

4. **Partial Merge - BA Footprint Changes Between Existing BA(s) and New BA(s) –**
   When a partial merge occurs between existing BA D and new BA E (see Diagram 3), the receiving BA E and or the transferring BA D may opt for either:
   a. Following the steps on the previous scenario to calculate both BA D's and BA E's adjusted PII_{Accum} balances and limits (see tables 4 and 4A). or **– Transferring BA and New BA Task**
   b. Maintaining the PII_{Accum} balances incurred by the assets being transferred thus retain its PII_{Accum} limits through the end of the current operating calendar year (see tables 4B and 4C) **– Transferring BA Task**
   c. If both BAs agree to opt for option b, then, the transferring BA will provide the previous calendar year's integrated peak demand data (load serving BAs) or integrated hourly peak generation data (generation only BAs) to the newly created BA E for the calculation of its PIIAccum limits, per BAL-004-WECC-02 R1, 1.1 or 1.2 (see table 4C) - **– Transferring BA and New BA Task**

BEFORE MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
D	300	-110	500
E	0	0	0

Table 4

AFTER MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
D	280	-100	450
E	20	-10	50

Table 4A

BEFORE MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
D	300	-110	500
E	0	0	0

Table 4B

AFTER MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
D	300	-110	500
E	0	0	50

Table 4C

   d. Contact the WIT administrator to add the new BA E in WIT (or its successor) to start recording hourly PII_{Accum} balances as well as FBS, L_{10}, etc. **– New BA Task**

5. **New BA with New Generation**
   Like in the calculation and allocation of FRO and FBS, a new BA needs to calculate a PII_{Accum} limit to operate in the Western Interconnection and track in WIT. In the case of a new BA, an estimation of maximum generating capacity is used to establish its PII_{Accum} limit.

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For instance, a new generator has decided to create the new gen only BA (BA F on Diagram 6). The generator inside the new BA F has committed to deliver 100 MWh, via a long term structured deal, to a load serving entity operating inside BA C. In addition, the new generator has an additional 100 MWh of generating capacity available to sell in the day ahead and real-time market operating inside BA A. The sum of both, committed and available extra generating capacity, will be its PII_{Accum} limit. See table 5 below.

Hourly Generation	MWh
Committed	100
Available	100
Hourly Peak Gen	**200**

Table 5

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ATTACHMENT B

BA Housekeeping Tasks Checklist

Task	Balancing Authorities			NERC Staff	Regional Entity	Reliability Coordinator	Check Box
	Transferring	Receiving	New				
NERC Certification Process			R	A	I		☐
Obtain BA ID			R	I	I		☐
BA Map Bubble Diagram				R	I	I	☐
Model Revision				R	I	I	☐
Inadv. Interchange Transfers on NERC Inadvertent Portal	R	R		I	I	I	☐
FRO Calculation							
FERC 714 Sched II Part III Data or Similar	R	R		I			☐
BA-to-BA General 714 Data Submittal Form		R		I			☐
OY XXXX Report for BAL-003	I	I	I	R	I		☐
FBS Calculation							
FERC 714 Sched II Part III Data or Similar	R	R		I			☐
BA-to-BA General 714 Data Submittal Form		R		I			☐
FRS Form 1 FERC 714 Data Worksheet				R			☐
FRS Form 1	R/O	R/O	R/O	R			☐
FRS Form 2	R/O	R/O	R/O	R			☐
NERC BASS Updates				R			☐
Elect FBS if: -FRM Median>FRO and, -FRM Median>Min Abs. Fixed FBS Based on Interconnection Peak Demand	R	R		A			☐
FBS and L_{10} Values Report for BAL-003 OY	I	I	I	A/R	I	I	☐
Accumulated PII (WI)							
On/Off Peak PII_{Accum} Balances	R	R			I		☐
PII_{Accum} Limits/Extensions	R	R	R		I		☐
WIT FBS Changes and PII_{Accum} Balance Transfers	R	R	R		R		☐

R – Responsible A – Approve I - Informed R/O – Responsible/Optional

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ATTACHMENT C

BA to BA General 714 Data Submittal Form

balancing@nerc.com

Energy and Demand Data for BAL-003
FERC Form 714 Part II Schedule III Data
Data Year Select

Instructions:
1. Enter your contact information.
2. Select your Interconnection - drop down list
3. Select the year of the data - drop-down list
4. Select your BA acronym - the drop-down list is dependent on which Interconnection is selected.
5. Enter your BA's data on the form on the left. As filed with FERC, or equivalent, and after merge occurs
6. Enter comments about the change in footprint. For instance, if the BA(s) is transferring or receiving data. From what BA(s). Etc.
7. Submit through the BA Submittal Site (BASS) in the Non-714 Submittals file for your BA.

Submitter's Contact Information

Technical Contact Name	Email	Telephone	Date Submitted (mm/dd/yyyy)
Interconnecton	BA	Effective Date:	mm/dd/yyyy

	BAA Net Generation (c) (MWh)		BA Net Energy for Load (e) (MWh)		BA Net Gen + BA NEL (MWh)		Monthly Peak Demand (j) (MW)	
	As Filed	Adjusted	As Filed	Adjusted	As Filed	Adjusted	As Filed	Adjusted
JAN						-		
FEB						-		
MAR						-		
APR						-		
MAY						-		
JUN						-		
JUL						-		
AUG						-		
SEP						-		
OCT						-		
NOV						-		
DEC						-		
Total	-	-	-	-	-	-	-	-

Comments:

Balancing Authority Area Footprint Change Tasks – Reference Document 18

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Revision History		
Date	**Version**	**Comment**
2/28/2019	1.0	Initial document – addressed comments received from 45-day industry comment period.

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Appendix B – Detailed Power Cost Model Results

This run reflects limiting market purchases to 250 MW. It also shows the addition of WAPA imbalance charges. This establishes the baseline against which alternatives to WAPA imbalance were compared.

Optimal Dispatch - limited Market				
	Annual Totals			
Generator	MWh Generation	Hours with Generation > 0	Capacity Factor	Cost of Generation
HappyJack	83,829		0.33	$ 4,230,851
SilverSage	126,947		0.35	$ 8,078,890
Corriedale	153,506		0.34	$ 5,679,727
Colstrip	344,200	8,760	0.79	$ 7,661,892
Wygen1	43,079	8,689	0.98	$ 607,374
Wygen2	777,993	8,734	0.99	$ 10,969,026
Wygen3	878,414	8,745	0.96	$ 12,580,716
Wyodak	478,289	7,475	0.81	$ 7,226,874
NS2	524,050	6,596	0.75	$ 8,086,013
CPGS1	268,643	5,201	0.56	$ 5,713,432
LCT	147,642	4,139	0.43	$ 3,430,388
NSCT1	105,161	3,195	0.31	$ 2,550,627
GCT2	59,425	1,902	0.17	$ 1,659,028
BFCT	34,981	813	0.05	$ 1,244,391
BFEMD	-	-	0.00	$ -
Market	804,701	4,941		$ 12,357,664
Sum of Wind Generation	364,282			$ 17,989,468
Sum of Coal Generation	3,046,024			$ 47,131,896
Sum of Natural Gas Generation	615,852			$ 14,597,864
Sum of Diesel Generation	-			$ -
Sum of Market Energy	804,701			$ 12,357,664
Sum of Generation	4,830,858			$ 92,076,891
	WAPA imb sales			$ 296,417
	WAPA imb purchases			$ 694,454
	Net system cost			$ 92,474,928

NAES

Alternative 1 - 55 MW LF				
	Annual Totals			
Generator	MWh Generation	Hours with Generation > 0	Capacity Factor	Cost of Generation
HappyJack	83,829		0.33	$ 4,230,851
SilverSage	126,947		0.35	$ 8,078,890
Corriedale	153,506		0.34	$ 5,679,727
Colstrip	344,200	8,760	0.79	$ 7,661,892
Wygen1	42,073	8,546	0.96	$ 593,187
Wygen2	768,017	8,669	0.97	$ 10,828,379
Wygen3	856,977	8,618	0.93	$ 12,273,686
Wyodak	457,739	7,052	0.78	$ 6,916,377
NS2	513,328	6,472	0.73	$ 7,920,575
CPGS1	240,900	8,760	0.50	$ 4,895,088
LCT	165,069	4,533	0.48	$ 3,835,305
NSCT1	131,721	3,788	0.39	$ 3,194,825
GCT2	83,096	2,497	0.24	$ 2,319,880
BFCT	56,169	1,211	0.08	$ 1,998,123
BFEMD	-	-	0.00	$ -
Market	807,288	5,496		$ 12,898,134
Sum of Wind Generation	364,282			$ 17,989,468
Sum of Coal Generation	2,982,333			$ 46,194,096
Sum of Natural Gas Generation	676,955			$ 16,243,221
Sum of Diesel Generation	-			$ -
Sum of Market Energy	807,288			$ 12,898,134
Sum of Generation	4,830,858			$ 93,324,918

NAES

Alternative 1 - 94 MW LF				
	Annual Totals			
Generator	MWh Generation	Hours with Generation > 0	Capacity Factor	Cost of Generation
HappyJack	83,829		0.33	$ 4,230,851
SilverSage	126,947		0.35	$ 8,078,890
Corriedale	153,506		0.34	$ 5,679,727
Colstrip	344,200	8,760	0.79	$ 7,661,892
Wygen1	40,711	8,342	0.93	$ 573,995
Wygen2	761,139	8,661	0.97	$ 10,731,404
Wygen3	836,416	8,448	0.91	$ 11,979,220
Wyodak	444,344	6,804	0.76	$ 6,713,979
NS2	504,555	6,415	0.72	$ 7,785,221
CPGS1	240,900	8,760	0.50	$ 4,895,088
LCT	170,820	8,760	0.50	$ 3,968,917
NSCT1	146,726	4,084	0.43	$ 3,558,760
GCT2	99,176	2,866	0.28	$ 2,768,793
BFCT	74,781	1,475	0.11	$ 2,660,205
BFEMD	-	-	0.00	$ -
Market	802,808	5,763		$ 13,260,439
Sum of Wind Generation	364,282			$ 17,989,468
Sum of Coal Generation	2,931,366			$ 45,445,710
Sum of Natural Gas Generation	732,402			$ 17,851,763
Sum of Diesel Generation	-			$ -
Sum of Market Energy	802,808			$ 13,260,439
Sum of Generation	4,830,858			$ 94,547,379

Alternative 1 - 133 MW LF				
Generator	MWh Generation	Hours with Generation > 0	Capacity Factor	Cost of Generation
HappyJack	83,829		0.33	$ 4,230,851
SilverSage	126,947		0.35	$ 8,078,890
Corriedale	153,506		0.34	$ 5,679,727
Colstrip	344,200	8,760	0.79	$ 7,661,892
Wygen1	39,681	8,151	0.91	$ 559,475
Wygen2	748,449	8,604	0.95	$ 10,552,487
Wygen3	816,627	8,249	0.89	$ 11,695,794
Wyodak	431,501	6,638	0.74	$ 6,519,912
NS2	492,877	6,364	0.70	$ 7,605,027
CPGS1	240,900	8,760	0.50	$ 4,895,088
LCT	170,820	8,760	0.50	$ 3,968,917
NSCT1	170,820	8,760	0.50	$ 4,143,154
GCT2	113,630	3,188	0.32	$ 3,172,331
BFCT	94,768	1,711	0.14	$ 3,371,241
BFEMD	-	-	0.00	$ -
Market	802,303	5,956		$ 13,844,256
Sum of Wind Generation	364,282			$ 17,989,468
Sum of Coal Generation	2,873,335			$ 44,594,587
Sum of Natural Gas Generation	790,939			$ 19,550,732
Sum of Diesel Generation	-			$ -
Sum of Market Energy	802,303			$ 13,844,256
Sum of Generation	4,830,858			$ 95,979,043

NAES

Alternative 1 - 193 MW LF				
Generator	MWh Generation	Hours with Generation > 0	Capacity Factor	Cost of Generation
HappyJack	83,829		0.33	$ 4,230,851
SilverSage	126,947		0.35	$ 8,078,890
Corriedale	153,506		0.34	$ 5,679,727
Colstrip	344,200	8,760	0.79	$ 7,661,892
Wygen1	38,389	7,860	0.88	$ 541,254
Wygen2	737,371	8,569	0.94	$ 10,396,302
Wygen3	793,262	7,985	0.86	$ 11,361,163
Wyodak	415,963	6,498	0.71	$ 6,285,148
NS2	475,816	6,265	0.68	$ 7,341,767
CPGS1	240,900	8,760	0.50	$ 4,895,088
LCT	170,820	8,760	0.50	$ 3,968,917
NSCT1	170,820	8,760	0.50	$ 4,143,154
GCT2	175,200	8,760	0.50	$ 4,891,234
BFCT	115,760	1,955	0.17	$ 4,117,982
BFEMD	-	-	0.00	$ -
Market	788,075	6,008		$ 14,206,928
Sum of Wind Generation	364,282			$ 17,989,468
Sum of Coal Generation	2,805,001			$ 43,587,526
Sum of Natural Gas Generation	873,500			$ 22,016,374
Sum of Diesel Generation	-			$ -
Sum of Market Energy	788,075			$ 14,206,928
Sum of Generation	4,830,858			$ 97,800,296

NAES

Alternative 1 - 253 MW LF				
Generator	MWh Generation	Hours with Generation > 0	Capacity Factor	Cost of Generation
HappyJack	83,829		0.33	$ 4,230,851
SilverSage	126,947		0.35	$ 8,078,890
Corriedale	153,506		0.34	$ 5,679,727
Colstrip	344,200	8,760	0.79	$ 7,661,892
Wygen1	36,264	7,369	0.83	$ 511,291
Wygen2	714,142	8,380	0.91	$ 10,068,787
Wygen3	742,348	7,341	0.81	$ 10,631,966
Wyodak	377,011	6,198	0.64	$ 5,696,581
NS2	411,818	5,651	0.59	$ 6,354,295
CPGS1	240,900	8,760	0.50	$ 4,895,088
LCT	170,820	8,760	0.50	$ 3,968,917
NSCT1	170,820	8,760	0.50	$ 4,143,154
GCT2	175,200	8,760	0.50	$ 4,891,234
BFCT	350,400	8,760	0.50	$ 12,464,954
BFEMD	0	5	0.00	$ 88
Market	732,653	5,630		$ 14,179,518
Sum of Wind Generation	364,282			$ 17,989,468
Sum of Coal Generation	2,625,783			$ 40,924,812
Sum of Natural Gas Generation	1,108,140			$ 30,363,347
Sum of Diesel Generation	0			$ 88
Sum of Market Energy	732,653			$ 14,179,518
Sum of Generation	4,830,858			$ 103,457,233

H. CONFIDENTIAL PRICE AND COST FORECASTS

This appendix contains the price and cost forecast schedules for Cheyenne Light and Black Hills Power for the planning period of 2021 through 2040 that were used in the IRP modeling. All schedules in this Appendix, except for the Cheyenne Light Schedule H-3 and the Black Hills Power Schedule H-3, are confidential.

CHEYENNE LIGHT PRICE AND COST FORECASTS

Confidential Schedule H-1. Cheyenne Light: Market Clearing Price Forecasts - CO West Market - Base Case

Confidential report removed.

Confidential Schedule H-2. Cheyenne Light: Seasonal Firm Market Price Forecasts - AZ-PV Market - Base Case

Confidential report removed.

Schedule H-3. Cheyenne Light: Capacity Charge

2021 Black & Veatch Busbar Cost Study
Cheyenne Light: Capacity Charge

Confidential Appendix H
Schedule H-3

Cheyenne Light Model - 1x0 LM6000 PF + SCCT				Joint Model - 1x0 LM6000 PF + SCCT			
	Capital	Fixed O&M	Total		Capital	Fixed O&M	Total
Year	$/kW	$/kW-Yr	$/kW-Yr	Year	$/kW	$/kW-Yr	$/kW-Yr
2021	117.96	60.90	178.86	2021	116.76	60.90	177.66
2022	119.73	61.81	181.55	2022	118.52	61.81	180.33
2023	121.53	62.74	184.27	2023	120.29	62.74	183.03
2024	123.35	63.68	187.03	2024	122.10	63.68	185.78
2025	125.20	64.64	189.84	2025	123.93	64.64	188.57
2026	127.08	65.61	192.69	2026	125.79	65.61	191.39
2027	128.99	66.59	195.58	2027	127.67	66.59	194.27
2028	130.92	67.59	198.51	2028	129.59	67.59	197.18
2029	132.89	68.60	201.49	2029	131.53	68.60	200.14
2030	134.88	69.63	204.51	2030	133.51	69.63	203.14
2031	136.90	70.68	207.58	2031	135.51	70.68	206.19
2032	138.96	71.74	210.69	2032	137.54	71.74	209.28
2033	141.04	72.81	213.85	2033	139.61	72.81	212.42
2034	143.16	73.91	217.06	2034	141.70	73.91	215.60
2035	145.30	75.01	220.32	2035	143.82	75.01	218.84
2036	147.48	76.14	223.62	2036	145.98	76.14	222.12
2037	149.69	77.28	226.98	2037	148.17	77.28	225.45
2038	151.94	78.44	230.38	2038	150.39	78.44	228.83
2039	154.22	79.62	233.84	2039	152.65	79.62	232.27
2040	156.53	80.81	237.34	2040	154.94	80.81	235.75

Confidential Schedule H-4. Cheyenne Light: Natural Gas Price Forecast - Rockies Market - Base Case

Confidential report removed.

Confidential Schedule H-5. Cheyenne Light: Market Clearing Price Forecasts - CO West Market - High Gas Case

Confidential report removed.

Confidential Schedule H-6. Cheyenne Light: Seasonal Firm Market Price Forecasts - AZ-PV Market - High Gas Case

Confidential report removed.

Confidential Schedule H-7. Cheyenne Light: Natural Gas Price Forecast - Rockies Market - High Gas Case

Confidential report removed.

Confidential Schedule H-8. Cheyenne Light: Market Clearing Price Forecasts - CO West Market - Low Gas Case

Confidential report removed.

Confidential Schedule H-9. Cheyenne Light: Seasonal Firm Market Price Forecasts - AZ-PV Market - Low Gas Case

Confidential report removed.

Confidential Schedule H-10. Cheyenne Light: Natural Gas Price Forecast - Rockies Market - Low Gas Case

Confidential report removed.

Confidential Schedule H-11. Cheyenne Light: Market Clearing Price Forecasts - CO West Market - CO_2 Tax Case

Confidential report removed.

Confidential Schedule H-12. Cheyenne Light: Seasonal Firm Market Price Forecasts - AZ-PV Market - CO_2 Tax Case

Confidential report removed.

Confidential Schedule H-13. Cheyenne Light: Emissions Costs for Electric Generators - CO_2 Tax Case

Confidential report removed.

BLACK HILLS POWER PRICE AND COST FORECASTS

Confidential Schedule H-1. Black Hills Power: Market Clearing Price Forecasts - CO West Market - Base Case

Confidential report removed.

Confidential Schedule H-2. Black Hills Power: Seasonal Firm Market Price Forecasts - AZ-PV Market - Base Case

Confidential report removed.

Schedule H-3. Black Hills Power: Capacity Charge

2021 Black & Veatch Busbar Cost Study
Black Hills Power: Capacity Charge

Confidential Appendix H
Schedule H-3

Black Hills Power Model - 1x0 LM6000 PF + SCCT				Joint Model - 1x0 LM6000 PF + SCCT			
	Capital	Fixed O&M	Total		Capital	Fixed O&M	Total
Year	$/kW	$/kW-Yr	$/kW-Yr	Year	$/kW	$/kW-Yr	$/kW-Yr
2021	116.56	60.90	177.46	2021	116.76	60.90	177.66
2022	118.31	61.81	180.12	2022	118.52	61.81	180.33
2023	120.08	62.74	182.82	2023	120.29	62.74	183.03
2024	121.88	63.68	185.56	2024	122.10	63.68	185.78
2025	123.71	64.64	188.35	2025	123.93	64.64	188.57
2026	125.56	65.61	191.17	2026	125.79	65.61	191.39
2027	127.45	66.59	194.04	2027	127.67	66.59	194.27
2028	129.36	67.59	196.95	2028	129.59	67.59	197.18
2029	131.30	68.60	199.90	2029	131.53	68.60	200.14
2030	133.27	69.63	202.90	2030	133.51	69.63	203.14
2031	135.27	70.68	205.95	2031	135.51	70.68	206.19
2032	137.30	71.74	209.03	2032	137.54	71.74	209.28
2033	139.36	72.81	212.17	2033	139.61	72.81	212.42
2034	141.45	73.91	215.35	2034	141.70	73.91	215.60
2035	143.57	75.01	218.58	2035	143.82	75.01	218.84
2036	145.72	76.14	221.86	2036	145.98	76.14	222.12
2037	147.91	77.28	225.19	2037	148.17	77.28	225.45
2038	150.13	78.44	228.57	2038	150.39	78.44	228.83
2039	152.38	79.62	232.00	2039	152.65	79.62	232.27
2040	154.66	80.81	235.48	2040	154.94	80.81	235.75

Confidential Schedule H-4. Black Hills Power: Natural Gas Price Forecast - Rockies Market & Colorado Market - Base Case

Confidential report removed.

Confidential Schedule H-5. Black Hills Power: Oil Price Forecasts - No. 2 Distillate - Base Case

Confidential report removed.

Confidential Schedule H-6. Black Hills Power: Market Clearing Price Forecasts - CO West Market - High Gas Case

Confidential report removed.

Confidential Schedule H-7. Black Hills Power: Seasonal Firm Market Price Forecasts - AZ-PV Market - High Gas Case

Confidential report removed.

Confidential Schedule H-8. Black Hills Power: Natural Gas Price Forecast - Rockies Market & Colorado Market - High Gas Case

Confidential report removed.

Confidential Schedule H-9. Black Hills Power: Market Clearing Price Forecasts - CO West Market - Low Gas Case

Confidential report removed.

Confidential Schedule H-10. Black Hills Power: Seasonal Firm Market Price Forecasts - AZ-PV Market - Low Gas Case

Confidential report removed.

Confidential Schedule H-11. Black Hills Power: Natural Gas Price Forecast - Rockies Market & Colorado Market - Low Gas Case

Confidential report removed.

Confidential Schedule H-12. Black Hills Power: Market Clearing Price Forecasts - CO West Market - CO_2 Tax Case

Confidential report removed.

Confidential Schedule H-13. Black Hills Power: Seasonal Firm Market Price Forecasts - AZ-PV Market - CO_2 Tax Case

Confidential report removed.

Confidential Schedule H-14. Black Hills Power: Emissions Costs for Electric Generators - CO_2 Tax Case

Confidential report removed.

I. ENERGY MARKET PARTICIPATION ANALYSIS

This market analysis quantified the potential benefits of both Cheyenne Light and Black Hills Power participating in the California ISO (CAISO) Western Energy Imbalance Market (WEIM) and in the Southwest Power Pool (SPP) Western Energy Imbalance Service (WEIS) market.

WEIM, a balancing energy market located across the western states and British Columbia, optimizes generator dispatch between BAs every 15 minutes in the real-time pre-dispatch (RTPD) market and every five minutes in the real-time market (RTM). WEIS, an energy imbalance market launched in February 2021 and operated by SPP across several midwestern states, centrally balances regional generation and load every five minutes. Dubbed the real-time balancing market (RTBM), it provides reliability and affordable energy to its eight initial participants.

This market analysis concluded that by participating in both WEIM and WEIS, Cheyenne Light and Black Hills Power customers could realize gross annual benefits. Participating in WEIM potentially brings much higher gross benefits, by as much as three times over participating in WEIS.

Real-Time Market Participation Benefits Analysis for Black Hills Energy

March 2021

Energy+Environmental Economics

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Real-Time Market Participation Benefits Analysis for Black Hills Energy

March 2021

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Energy and Environmental Economics, Inc.
44 Montgomery Street, Suite 1500
San Francisco, CA 94104
415.391.5100
www.ethree.com

Prepared For:
Black Hills Energy (BHE)

Prepared By:

Jack Moore, Xiaoxuan Hou, Patrick O'Neill, Chen Zhang, Adrian Au
Energy and Environmental Economics, Inc. (E3)

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Acronyms

BA	Balancing Authority
BAU	Business-As-Usual
BHE	Black Hills Energy
CAISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine
CT	Combustion Turbine (Simple Cycle)
DA	Day Ahead
EIM	Energy Imbalance Market
EIS	Energy Imbalance Service
HA	Hour Ahead
RTBM	EIS Real-Time Balancing Market (5-minute market)
RTM	EIM Real-Time Market (5-minute market)
RTPD	EIM Real-Time Pre-Dispatch (15-minute market)
SPP	Southwest Power Pool

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Executive Summary

In August 2020, Black Hills Energy (BHE) engaged Energy and Environmental Economics, Inc. (E3) to quantify the potential benefits of BHE's participation in the Western Energy Imbalance Market (EIM) and in the Western Energy Imbalance Service market (EIS). This report summarizes the results of E3s analysis, which is supported by the system experience of BHE staff and builds on E3's modeling and markets expertise from completing over 14 previous EIM benefit studies for other entities.

This analysis indicates that **both EIM and EIS participation provide positive gross benefits annually to BHE customers**. Between the two, **EIM participation could bring higher gross benefits than the EIS** for BHE's customers. This result is based on both on a 2019 historical benchmark scenario and a 2025 future scenario. In each modeled scenario, the EIM/EIS market resulted in lower total cost for BHE to serve load, driven by net market revenues from real-time energy sales from BHE to other market entities, as well as lower cost when BHE can dispatch down its own generation fleet and purchase at lower market prices.

Table 1: BHE's EIM and EIS participation benefits summary

Scenario	Total EIM Benefits ($MM/yr)	Total EIS Benefits ($MM/yr)
Historical Benchmark	10.3 – 12.9	3.2 – 4.0
Future Base	11.6 – 14.3	4.3 – 5.3

Table 1 shows the range of annual benefits that EIM and EIS participation can potentially provide. The higher range of the estimated benefits are calculated based off the original EIM and EIS market prices. The lower range is calculated based off conservative real-time price bounds where the EIM and EIS prices are bounded between [-$30/MWh; $100/MWh]. These prices-bounded benefits help provide a more conservative estimate and implicitly consider other externalities that may affect potential real-time market benefits. This report will only focus on the findings related to the original non-price bounded benefit results for the sake of discussion.

This analysis focuses on gross economic benefits and does not reflect BHE's cost of implementation. Since production modeling cannot capture all the market realities, the displayed results should only be read as an indicative view of the potential benefits. The main report provides detailed discussions on the assumptions that these results rely on, as well as potential limitations of the modeling process.

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1 Study Context

1.1 Black Hills System Overview

Black Hills Energy provides regulated electric utility services under the subsidiaries: Black Hills Colorado Electric, Black Hills Power, and Cheyenne Light Fuel and Power Company. This study focuses on the subsection of Black Hills Energy that includes Black Hills Power and Cheyenne Light Fuel and Power Company Energy. Black Hills Colorado Electric is already set to join the Western Energy Imbalance Market (EIM) along with three other Colorado utilities[1] in 2022. Black Hills Power and Cheyenne Light Fuel and Power Company Energy, which will be referred to as Black Hills Energy (BHE) in this report, serve a combined 110,000 customers in western South Dakota, Wyoming, and southern Montana. As of 2019, the average electricity load is 475 MW with a peak of nearly 700 MW. BHE's service areas fall within the boundaries of the Western Area Power Administration's (WAPA) Colorado Missouri balancing authority area (BAA), known as WACM. WAPA is the balancing authority (BA) tasked with matching real-time supply with demand within the WACM balancing area. BHE's generation mix consists of coal, gas, fuel oil, and wind units. A combination of owned and contracted generation is used to meet internal BHE load. Additionally, BHE has access to regional trading hubs at Palo Verde and Mid-C where it can transact with other regional entities on a day-

[1] https://www.caiso.com/Documents/FourColoradoUtilities-Join-WestsReal-timeEnergyMarket.pdf

ahead basis as well as at an hour-ahead basis up to 30 minutes before the start of the operating hour. Currently, BHE has a total transmission import and export capability of 800 MW, roughly 400 MW to PacifiCorp East (PACE) and 400 MW to the rest of WACM. BHE also transacts in small amounts with entities with the Rockies region up to real time, however within the operating hour BHE will dispatch internal generation to account for changes in weather conditions, and load variability in real-time.

1.2 Western Energy Imbalance Market (EIM) Overview

The Western EIM is a balancing energy market that optimizes generator dispatch between BAs every 15 and 5 minutes which represent the RTPD and RTM markets respectively.[2] Each hour, participants submit a base schedule of expected hourly generation and load, and bid prices at which they would increase or decrease generation within the hour. The EIM creates cost savings by: (1) using software tools to identify sub hourly transactions that produce an optimized dispatch and minimize production costs, while respecting transmission limits and reliability requirements; (2) bringing this optimized dispatch down to a 5-minute level; and (3) incorporating real-time unit commitment of quick-start generation.

Additionally, by allowing Balancing Authorities (BAs) to pool load and generation resources on a sub hourly basis, the EIM enables participants to reduce the number of units they individually need to dispatch to provide

[2] For more information regarding the EIM, see https://www.westerneim.com/pages/default.aspx.

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flexibility reserves within the hour.[3] Potential reserve reductions and reliability benefits are not quantified in this study, but may be additive to the economic benefits described in this report.

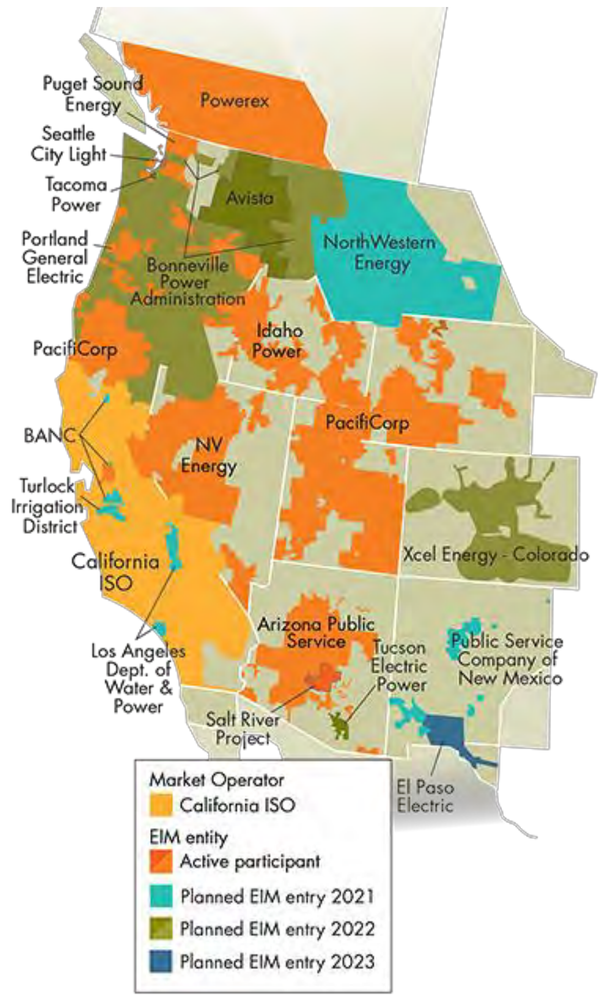
From initial operation in 2014 through December 2020, CAISO estimates that the EIM has provided $1.18 billion in savings for the participating entities. Participating entities during this time included: PacifiCorp, NV Energy, Arizona Public Service, Puget Sound Energy, Portland General Electric, Powerex, Idaho Power Company, Balancing Authority of Northern California, Seattle City Light, Salt River Project, and CAISO. Over that period, the EIM also helped the participants avoid the need to curtail approximately 1.32 TWh of solar and wind generation, saving nearly 587,000 metric tons (CO_2-equivalent) of greenhouse gas emissions.[4]

With the current participants, the Western EIM footprint covers more than 60% of the Western Interconnection load. Twelve new entrants have announced their plans and scheduled to join in the coming years (Figure 1). With those 12 new participants, the Western EIM footprint will cover more than 80% of total Western Interconnection load by 2023.

[3] While pooling of flex reserves can reduce variable dispatch and generator commitment costs over time as operators accumulate greater experience with the EIM, participation in the EIM does not reduce the physical generation capacity that a BA needs to serve peak loads and provide system flexibility. Long-term capacity decisions are beyond the scope of this report and are more appropriately examined using other analytical approaches and modeling tools.
[4] For more information regarding the detailed EIM benefits, see https://www.westerneim.com/Documents/ISO-EIM-Benefits-Report-Q4-2020.pdf

Study Context

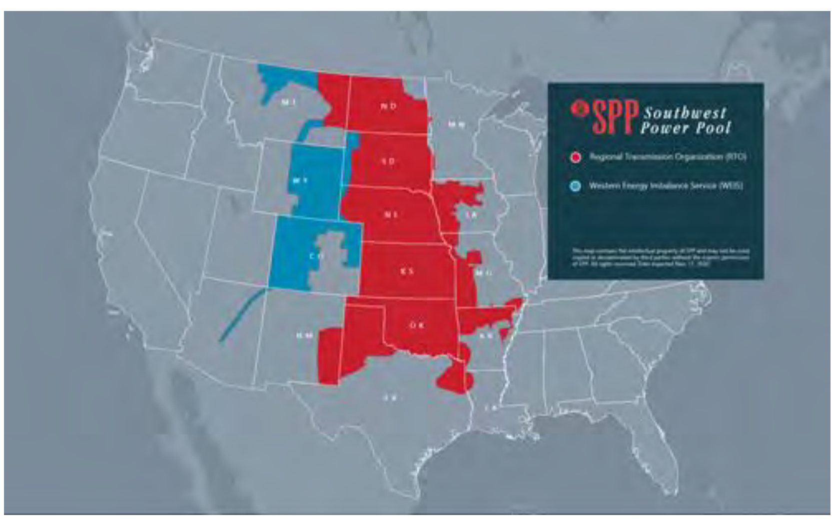
Figure 1: Current and planned footprint of the Western EIM



1.3 Western Energy Imbalance Service (EIS) Market Overview

The Western EIS is an energy imbalance market operated by SPP. The market centrally balances regional generation and load on a five-minute basis which is also dubbed the RTBM market, providing benefits including reliability and affordability of energy to its participants. The EIS market launched in February 2021 with eight initial participants: Basin Electric Power Cooperative, Deseret Power Electric Cooperative, Municipal Energy Agency of Nebraska, Tri-State Generation and Transmission Association, Western Area Power Administration (incl. Upper Great Plains West, Rocky Mountain Region, and Colorado River Storage Projects), and Wyoming Municipal Power Agency. The blue area in Figure 2 shows the current footprint of the Western EIS market.

Figure 2: Current footprint of the Western EIS (blue) and the SPP RTO (red)



2 Study Framework and Assumptions

2.1 Study Approach

This study is designed to quantify the **subhourly dispatch benefits** of EIM or EIS participation for BHE. These benefits represent the change to BHE generator dispatch cost (as a result of subhourly dispatch changes), plus revenue from BHE energy sales to the EIM/EIS, net of the cost of EIM/EIS energy purchases. To quantify these savings, E3 uses the PLEXOS production simulation software to compute real-time dispatch of generators in three cases: **Business-As-Usual (BAU) Case**, **EIM Participation Case**, and **EIS Participation Case**. The E3 team worked closely with BHE staff to develop a **Business-As-Usual (BAU) Case** that reflects BHE's current market arrangements (without EIM or EIS). Under normal conditions, when BHE's load, wind or solar changes on a subhourly basis compared to the hourly forecast, BHE must move the dispatch of its internal generation to meet these energy imbalances. In contrast, the **EIM Participation Case** and the **EIS Participation Case** allows BHE to make economic transactions with the EIM and EIS footprints on a 15-minute and 5-minute basis[5]. EIM and EIS transactions can thus provide BHE an

[5] The four stages are set up to reflect the CAISO EIM trading stages and applied consistently in all three cases for comparability. Since the EIS market does not have the 15-min trading stage in its actual operation, E3 ran an additional EIS case that only has the DA, HA, and 5-min stages. This additional case has shown

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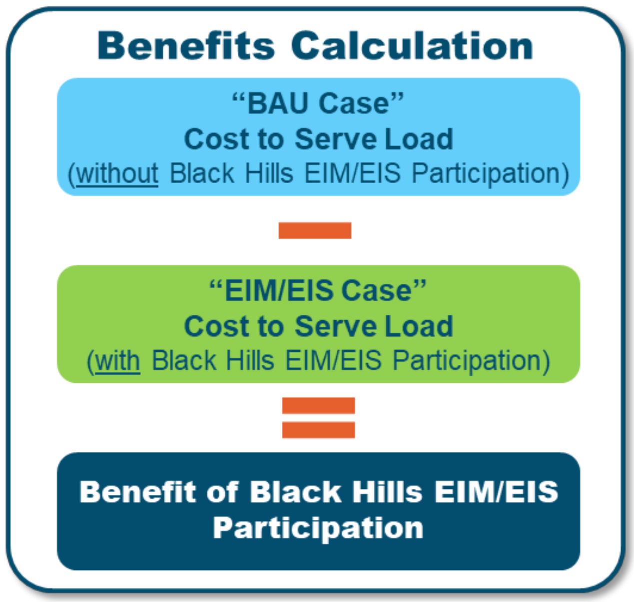
additional source of flexibility for balancing BHE's subhourly load changes, complementing BHE's own generating fleet capabilities.

Each simulation case produces a total cost to serve load, which consists of dispatch costs of BHE's internal generation, plus the costs of BHE imports, net of energy export revenues (which includes revenues made from sales to the EIM or EIS, when applicable). The reduction in the annual costs from the BAU case to the EIM or EIS Case represents the gross economic benefit for BHE. This benefits calculation is represented in Figure 3 below. It should be noted that this study does not consider implementation or ongoing costs associated with EIM or EIS participation.

minimal cost changes compared to the EIS Case with all four stages, which confirms that adding the 15-min stage has little effect on the EIS benefits results. Detailed results of the additional EIS case can be found in Section 5.2.2.3.

Figure 3: Framework for EIM/EIS benefit calculation



All cases are represented in PLEXOS using a four-stage simulation of generator commitment and dispatch, which first runs in hourly intervals (at day-ahead and hour-ahead stages), and then reflects subhourly operations, with BHE load and solar and wind generation changing every 5 minutes.

Finally, E3 calculates the benefits using two versions of real-time market prices. The first version uses the original market prices. The second uses real-time prices bounded between [-$30/MWh; $100/MWh]. These price bounded benefits help provide a more conservative estimate and implicitly take into account other externalities that may affect potential real-time market benefits.

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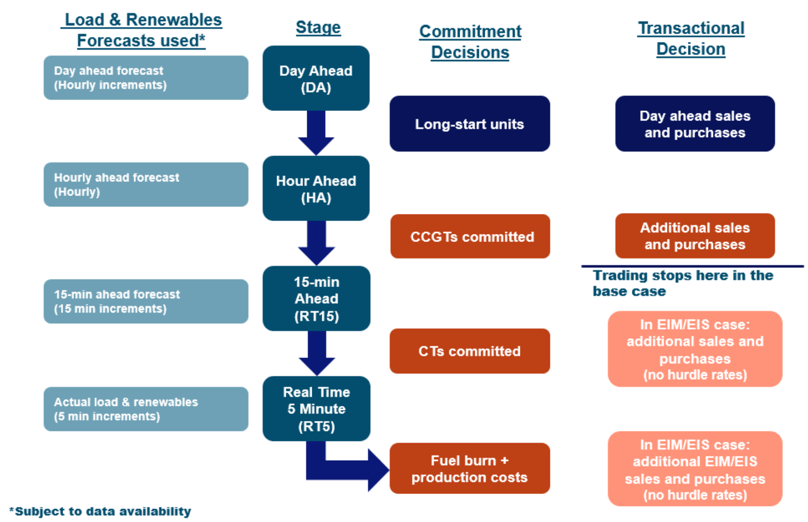
2.1.1 PLEXOS FOUR-STAGE, PRICE-DRIVEN SIMULATION

The study uses data provided by BHE staff for generator start-up costs, O&M costs, heat rates, and fuel costs as inputs to the PLEXOS unit commitment formulation and economic dispatch subject to reserve and zonal transmission constraints. The study models a full year of sequential operations at the hourly, 15-minute, and 5-minute timesteps, benchmarking to historical data for the 12-month period of 2019. To reflect the need to maintain system reliability, the model considers both contingency reserves (spinning and non-spinning) and operating reserves (flexibility/load-following and regulation) needs as a constraint on dispatch in the model, ensuring that sufficient committed generators have the capability to respond to changes in system needs.

Figure 4: PLEXOS four-staged modeling framework



2.1.2 BAU METHOD

To model the BHE system under a BAU scenario, the study assumes BHE only transacts within the bilateral markets in the day-ahead (DA) and hour-ahead (HA) stages of the model. Under this assumption, E3 models BHE as dispatching generators in the system against historical or forecasted prices provided by BHE in the DA and HA stages. The model assumes a $7/MWh hurdle rate on sales in the DA and HA stages to account for any potential transmission hurdles, and implicit minimum trader margins when selling into the bilateral markets.[6] As the sub hourly stages of the model are run, there are no more market transactions and BHE must dispatch internal generation to meet load and renewable variability.

2.1.3 EIM METHOD VS. EIS METHOD

Both EIM and EIS Cases assume the same unit commitment and transaction decisions as the BAU Case for the DA and HA stages, i.e., the only difference between the BAU Case and the EIM or EIS Case are the commitment and trading decisions made in the 15-min and 5-min real-time operation stages driven by the EIM or EIS market conditions.

In the EIM Case, the BHE system is modeled as dispatching generators against input EIM market price streams based on published historical or forecasted future prices. In the EIS Case, the BHE system is co-optimized

[6] The $7/MWh was chosen based on conversations with the BHE staff following testing a range of different premium values. Among all values tested, the $7/MWh result in the BAU case that benchmarks the best with BHE's historical system operation.

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with the external WACM market to generate EIS prices and BHE operations endogenously and simultaneously.

The reasons for the different treatment of the two cases are: 1) the EIM market is a well-established market that has sufficient historical prices to rely on, while the EIS market is relatively new and does not have much data available to dispatch the BHE system against; 2) the EIM market prices are largely dominated by CAISO, and BHE is on the edge of the market's wide footprint, which means BHE is unlikely to set the EIM market price. On the contrary, the EIS market footprint is much smaller, at least at the current stage, and closer to the BHE system, which means BHE's operation might affect the realized EIS market prices.

As a result of such treatment difference, the EIM benefits results that this study finds may be on the higher end while the EIS benefits results may be conservative. But we do not think the slight difference will affect the directional conclusions drawn from the study. Section 4.1 provides more discussions on the method difference and its impact on the results.

2.2 Study Scenarios

The study simulated BAU, EIM, and EIS cases for a single historical year (2019) scenario for benchmarking. In addition, E3 worked closely with BHE to identify assumptions for a future study year of 2025 to project the ongoing EIM/EIS benefits. The future year assumptions including load growth, resource additions and retirements, and market and fuel price changes are discussed in more details in the following section.

2.3 Study Input Data

2.3.1 TRANSMISSION TOPOLOGY

The PLEXOS model includes three zones that interacts with each other as shown in Figure 5.

- **BHE**: BHE system where all BHE load and generation capacity reside
- **PACE and Rest of WECC**: modeled as an external market with DA and HA price streams in the BAU Case. This zone also provides the 15-min and 5-min EIM prices in the EIM case that BHE can trade at
- **WACM (Western)**: WACM system with WACM load and generation capacity fully represented. As a result, BHE can interact with WACM at DA and HA stages, as well as at the real-time stages in the EIS Case

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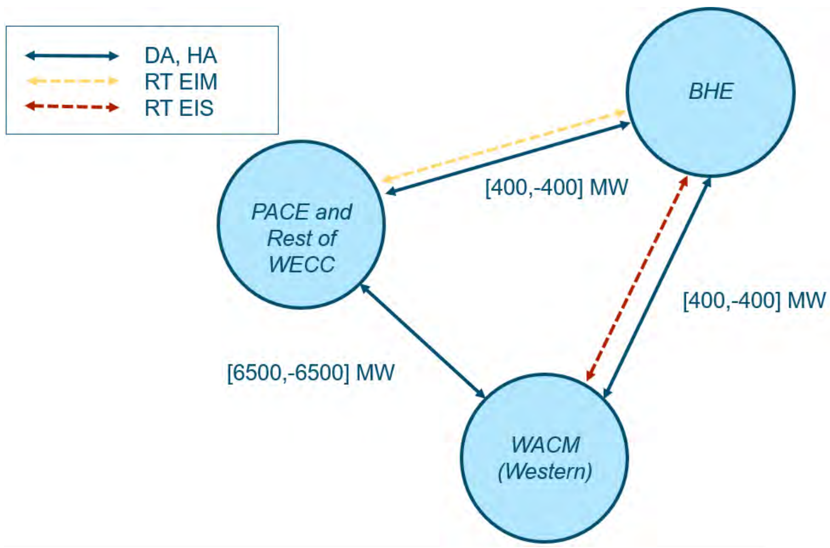
Figure 5: PLEXOS topology and inter-zonal transfer capabilities



2.3.2 INPUT DATA ASSUMPTIONS

For both the historical year 2019 scenario and future year 2025 scenario, BHE provided key assumptions and inputs including load profiles, generator characteristics, renewable resources output profiles, and fuel prices for its service territory.

Historical DA and HA prices were also obtained from BHE. Prices in real-time stages (RT5 and RT15) for the historical EIM case were populated with actual CAISO EIM prices (from OASIS). For the future scenario, DA stage prices were obtained from BHE and Hitachi ABB Power Grids' Spring 2020 Power Reference Case. These hourly forecasted DA prices were then combined with historical price patterns in the HA and RT stages to create price forecast for the future scenario.

The rest of the WACM region was modelled within PLEXOS to fully capture EIS benefits for BHE. Individual WACM generators, as well as fuel, and load data were provided from a previous TEPPC Database and adjusted using S&P Global data to create inputs for the 2019 as well as the 2025 scenario.

Detailed input data assumptions can be found in Appendix 5.1.

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3 Study Results

3.1 Summary of Study Results

The studied scenarios indicate that BHE will benefit from participating in either an EIM or EIS real-time market. BHE could see sub hourly annual operational cost saving due to EIM participation in the range of $10 million to $14 million annually and savings of $3 million to $5 million annually due to participation in the EIS market. These benefits are summarized in Table 2. The lower range of these estimated annual benefits are calculated based off conservative real-time price bounds where the EIM and EIS prices are bounded between [-$30/MWh; $100/MWh]. These prices bounded benefits help provide a more conservative estimate and implicitly consider other externalities that may affect potential real-time market benefits. This report will only focus on the findings related to the original non-price bounded benefit results for the sake of discussion.

Table 2. Summary of scenario benefits

Scenario	Total EIM Benefits ($MM/yr)	Total EIS Benefits ($MM/yr)
Historical Benchmark	10.3 – 12.9	3.2 – 4.0
Future Base	11.6 – 14.3	4.3 – 5.3

3.2 Historical Benchmark Scenario

The 2019 Historical Benchmark Scenario shows that BHE will experience gross annual EIM benefits of around $12.9 million and annual EIS benefits of $4 million. Table 3 provides a summary of annual changes in BHE generation and transaction volumes, as well as resulting cost changes in both the BAU and EIM cases.

Table 3: BHE's cost and dispatch in historical EIM scenario

	Total Generation Cost ($MM/year)			Total Energy (GWh)		
Resource	BAU	EIM	Delta	BAU	EIM	Delta
BHE Coal	$40.2	$42.3	$2.1	3,145	3,277	132
BHE CCGT	$11.2	$13.5	$2.2	635	776.2	141
BHE CT	$3.7	$14.6	$10.8	144	681.2	537
BHE Diesel	$0.1	$0.2	$0.1	0.2	1	0.8
BHE Renewables	-	-	-	242	242	-
Total BHE Gen	$55.3	$70.5	$15.3	4,167	4,978	811
DA/HA Purchases	$9.8	$9.8	-	465	465	-
RT Purchases	-	$1.5	$1.5	-	158	158
DA/HA Sales	($13.3)	($13.3)	-	(462)	(462)	-
RT Sales	-	($29.7)	($29..7)	-	(970)	(970)
Total Cost	**$51.7**	**$38.8**	**($12.9)**	**4,171**	**4,170**	**1**

Table 4 summarizes BHE generation and transaction volumes for both the BAU and EIS cases for Historical Benchmark Scenario.

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Table 4: BHE's cost and dispatch in historical EIS scenario

	Total Generation Cost ($MM/year)			Total Energy (GWh)		
Resource	BAU	EIS	Delta	BAU	EIS	Delta
BHE Coal	$40.2	$43.6	$3.3	3,145	3,379	234
BHE CCGT	$11.2	$14.0	$2.8	635	817.1	182
BHE CT	$3.7	$10.1	$6.4	144	490.3	346
BHE Diesel	$0.1	$0.0	($0.0)	0.2	0.3	0
BHE Renewables	-	-	-	242	242	-
Total BHE Gen	$55.3	$67.7	$12.5	4,167	4,929	762
DA/HA Purchases	$9.8	$9.8	-	465	465	-
RT Purchases	-	$0.5	$0.5	-	32	32
DA/HA Sales	($13.3)	($13.3)	-	(462)	(462)	-
RT Sales	-	($17.0)	($17.0)	-	(795)	(795)
Total Cost	**$51.7**	**$47.7**	**($4.0)**	**4,171**	**4,170**	**1**

3.3 Future Base Scenario

The Future Base Scenario estimates annual EIM participation benefits of $14.4 million and EIS benefits of $5.3 million. The breakdown of these savings can be seen in Table 5 and Table 6 illustrates the various elements of BHE's estimated EIS benefits. Similar to the EIM case, BHE is able to profit from the real-time EIS market mostly by increasing internal generation and selling into the EIS market. On aggregate, expensive BHE CT units are backed down providing some generator cost savings while the rest of BHE's low-cost thermal fleet increases generation to contribute towards the 571

GWh of sell into the real-time market creating revenues. At the same time, the 87 GWh of imports from the EIS provides additional cost savings.

The EIM benefits breakdown in Table 5 shows that BHE's low-cost thermal fleet increases generation within the sub hourly timeframe to help provide a total of 849 GWh of exports to the real-time EIM market thereby creating revenues for BHE. Though there is an aggregate increase in BHE generation, there are intervals where BHE can profit from 178 GWh of imports from the real-time markets by backing down internal generation to take advantage of low EIM prices to create savings opportunities.

Table 5: BHE's cost and dispatch in future EIM scenario

	Total Generation Cost ($MM/year)			Total Energy (GWh)		
Resource	BAU	EIM	Delta	BAU	EIM	Delta
BHE Coal	$45.1	$48.9	$3.8	3,046	3,281	235
BHE CCGT	$15.2	$20.1	$4.9	465	657.0	193
BHE CT	$2.5	$12.3	$9.8	41	282.8	242
BHE Diesel	$0.5	$0.3	($0.2)	2	1	(1)
BHE Renewables	-	-	-	609	609	-
Total BHE Gen	$63.2	$81.5	$18.3	4,162	4,831	669
DA/HA Purchases	$19.7	$19.7	-	697	697	-
RT Purchases	-	$3.6	$3.6	-	178	178
DA/HA Sales	($11.4)	($11.4)	-	(334)	(334)	-
RT Sales	-	($36.3)	($36.3)	-	(849)	(849)
Total Cost	**$71.5**	**$57.2**	**($14.3)**	**4,525**	**4,523**	**2**

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Table 6 illustrates the various elements of BHE's estimated EIS benefits. Like the EIM case, BHE can profit from the real-time EIS market mostly by increasing internal generation and selling into the EIS market. On aggregate, expensive BHE CT units are backed down providing some generator cost savings while the rest of BHE's low-cost thermal fleet increases generation to contribute towards the 571 GWh of sell into the real-time market creating revenues. At the same time, the 87 GWh of imports from the EIS provides additional cost savings.

Table 6: BHE's cost and dispatch in future EIS scenario

	Total Generation Cost ($MM/year)			Total Energy (GWh)		
Resource	BAU	EIS	Delta	BAU	EIS	Delta
BHE Coal	$45.1	$50.4	$5.3	3,046	3,380	334
BHE CCGT	$15.2	$19.3	$4.1	465	626.1	162
BHE CT	$2.5	$1.9	($0.5)	41	27.7	(13)
BHE Diesel	$0.5	$0.1	($0.4)	2	0	(2)
BHE Renewables	-	-	-	609	609	-
Total BHE Gen	$63.2	$71.7	$8.5	4,162	4,644	482
DA/HA Purchases	$19.7	$19.7	-	697	697	-
RT Purchases	-	$1.8	$1.8	-	87	87
DA/HA Sales	($11.4)	($11.4)	-	(334)	(334)	-
RT Sales	-	($15.6)	($15.6)	-	(571)	(571)
Total Cost	**$71.5**	**$66.2**	**($5.4)**	**4,525**	**4,523**	**2**

BHE's 2025 annual EIM benefits are estimated to be larger than EIS benefits due to a combined effect of greater volume of sales in real-time and at higher prices summarized in Table 7. Participation in the EIM allows BHE to sell 849 GWh as opposed to selling 571 GWh within the EIS market. These larger volumes of sales in the EIM occur on average at a price of $43/MWh whereas the sales occurring in the EIS are happening at a much lower $27/MWh. The market prices experienced in the EIM allow BHE to generate more sales with better spreads, due to higher prices relative to its lower cost thermal fleet, and offer more volatility compared to the newly developed EIS market and its prices. It is also worth noting that BHE also experiences slightly better savings when purchasing from the EIM on a per MWh basis at an average price of $20.20/MWh compared to the average EIS purchase price of $20.70/MWh.

Table 7: BHE's EIM and EIS market transaction comparison

	EIM		EIS	
	Total Transaction Volume (GWh)	Average Price ($/MWh)	Total Transaction Volume (GWh)	Average Price ($/MWh)
DA/HA Purchases	697	$28.27	697	$28.27
RT Purchases	**178**	**$20.20**	**87**	**$20.70**
DA/HA Sales	(334)	$33.99	(334)	$33.99
RT Sales	**(849)**	**$42.71**	**(571)**	**$27.38**

Figure 7 and Figure 8 illustrate how the EIM offers more frequent sales opportunities at higher prices relative to the EIS market. The daily price volatility for each month of the year is highlighted in the Figures below and show a noticeable difference in volatility between the two markets. The larger and more frequent price spikes seen in the EIM offer more opportunities for BHE to provide more exports and additional sales relative to the EIS market which as less volatility and price spikes.

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Figure 6 Hour-Ahead monthly price volatility compared to the maximum marginal cost range from a selection of BHE CTs

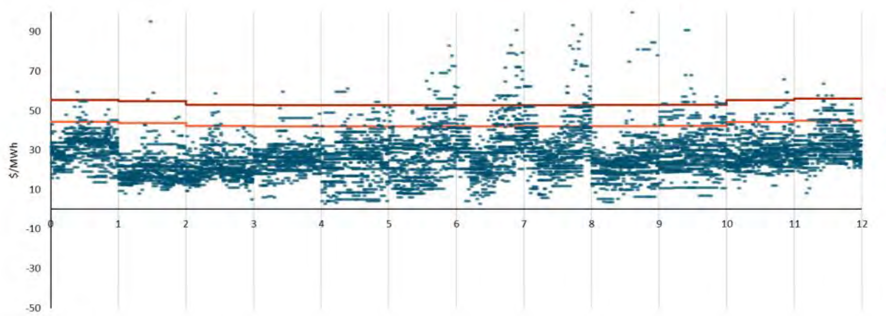


Figure 7 EIM RTPD monthly price volatility compared to the maximum marginal cost range from a selection of BHE CTs

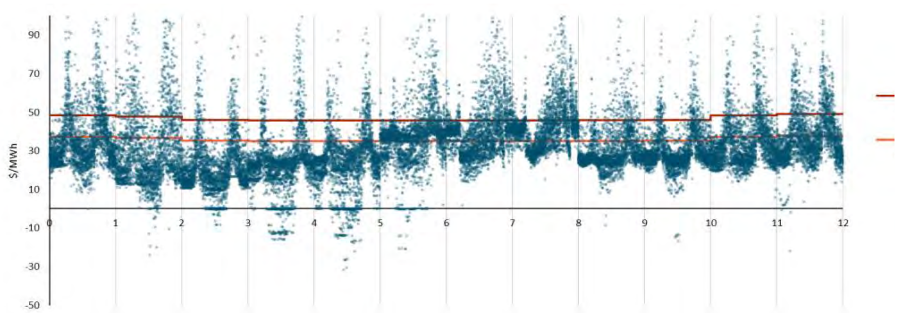
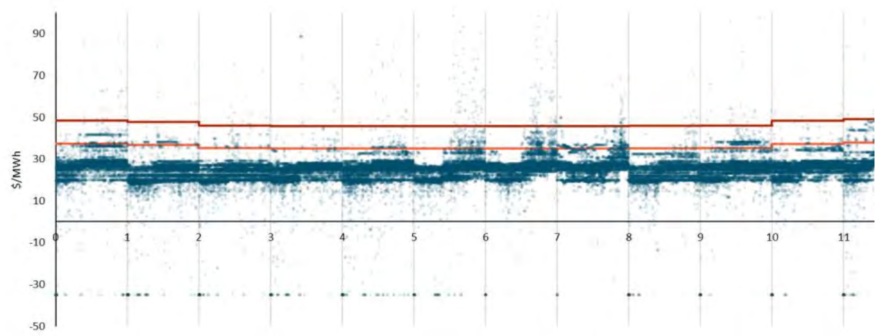


Figure 8 EIS RTBM monthly price volatility compared to the maximum marginal cost range from a selection of BHE CTs



In addition to greater price variability in the EIM, the higher average EIM price ($34/MWh) relative to BHE's thermal fleet costs allows them to increase output and generate more revenue from sales on average compared to the EIS market ($26/MWh). Figure 7 and Figure 8 separately compare EIM RTPD and EIS RTBM market prices to the marginal cost range of three of BHE's CTs that are seen to be on the margin internally. Depending on power output and the fuel price, the short run marginal cost of these units varies roughly between $35/MWh and $50/MWh. The number of real-time intervals where the price is at or above this range is noticeably different between the two markets.

Figure 6 shows where these CT units stand within the hour-ahead market which has an additional $7/MWh hurdle rate of sales on top of the short run marginal costs of the CT units. Comparing Figure 6 and Figure 7, the hour-ahead market offers little sales opportunity for BHE's marginal generation, however once BHE has access to the higher EIM market prices

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without a hurdle rate, these marginal units can help generate high sales revenues by increasing generation on these units.

In a scenario where BHE participates in the EIS market (Figure 8), there are very few moments when these marginal CT units can help generate sales revenues, as the number of real-time intervals where the EIS market price is above the largest short run marginal cost of the CT units are much smaller compared to the amount seen within the EIM market and is on par with the amount seen in the hour-ahead market. In fact, there are several intervals where the EIS price is lower than the lowest short run marginal cost of the CT units and would be more economical to dispatch these CT units down at some intervals in the EIS market to import power at a lower price relative to BHE's marginal unit. If there are intervals in the hour-ahead stage that have some of these CT units generating, either to meet internal load or sell into the bilateral market, but once in the EIS market the price at that same interval is found to be below the CT units' marginal cost then BHE will back down these units to import cheaper power from the market. This is reflected in Table 6 where CT generation in the EIS case is reduced relative to the BAU case.

4 Conclusions

4.1 Discussion of Results

In both the backward looking (the 2019 cases) and the near-term future looking (the 2025 cases), this study indicates that BHE participation in a real-time market, regardless of EIM or EIS, would enable some gross benefits. Most of the gross benefits come from BHE selling to the real-time markets, thanks to BHE's low-cost dispatchable thermal fleet and the generous transmission capability between BHE and the external markets. BHE can generate significant sales revenues by ramping up its thermal fleet quickly when seeing favorable market prices. Such sales revenues generate profits that help lower BHE's total production costs, thereby providing savings to its customers. BHE also benefits from being able to purchase from the EIM/EIS markets and saving on local generation costs when prices are low. But the benefits from purchases are much less than those from sales. From 2019 to 2025, both the EIM and EIS cases show a slight increase in the real-time market participation benefits, indicating that such benefits are sustainable at least in the near-term.

Between the two real-time markets, joining the EIM market yields larger benefits (10~14 million vs. 3~5 million) because the EIM market has greater price volatility and more interval price spikes, which provide more purchase and sales opportunities. This is likely driven by two factors. First, the EIM market has a bigger footprint which reflects greater load and resource

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diversity, as well as the arbitrage potential caused by time zone difference across its participants. Second, the EIM market has higher renewable penetration, whose intermittency can create greater real-time price volatilities.

Although not affecting our conclusion that joining the EIM shows higher benefits, a few caveats should be noted when interpreting the calculated benefits results.

First, both the EIM and EIS cases assume few restrictions on BHE's CT operation, such as maximum number of starts per day or over the year. If such restrictions were put in place, we would expect lower EIM/EIS benefits because BHE would not be able to fully capture all the sales opportunities.

Second, the EIM benefits may be on the higher end of the expected range even beyond the CT disclaimer. As explained in section 2.1.3, in this study, BHE can sell to the EIM at a high price as much as it can deliver without affecting the prices. This may not be true in the real-world, where high amount of BHE sales to the market can lower the EIM prices at the node, hence lower BHE's revenues. In addition, potential downstream transmission constraints may reduce total amount of BHE sales during high priced hours when other entities including PACE also dispatch to make EIM sales that compete for transmission, which is not captured in this study. Finally, carbon charges may apply in hours when California is importing from the EIM, adding to the effective coal bids cost, or put some sales out of the money, which is not incorporated in this study.

Third, the EIS benefits may be on the conservative side. As explained in section 2.1.3, the EIS prices are generated within PLEXOS. Market prices from a production simulation model typically have fewer instances of variability than real-world observations. As a result, this study may be undercounting some of the opportunities for BHE to buy from or sell to the EIS market.

Finally, the presented EIM/EIS benefits results are gross benefits and do not have potential administrative costs factored in.

4.2 Comparison to Other Real-time Market Benefits Analysis

Similar real-time market benefits analyses have been conducted for other WECC entities considering participation in markets such as the EIM. For a utility of its size, benefits shown here for BHE are near the upper range of those projected for other entities. This relatively high level of benefits for BHE are driven by the combination of several factors. First, BHE geographic location far from many of the other market participants results in BHE having significant load and renewable profile diversity compared to many of the EIM participants. In addition, BHE has an efficient and flexible dispatchable generation fleet compared to other entities, which enables opportunities to make economic sales to the EIM or EIS market on short notice in real time, resulting in net revenues for BHE. The distance from highly liquid market trading hubs may lead fewer of these sales opportunities to be already taken in the day ahead and hour ahead time frame. Other input assumptions can also impact the EIM benefits. For

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example, BHE may have access to lower-cost fuels compared to other regions, especially the entities in California and the Southwest, which also provides BHE with some competitive advantages.

5 Appendix

5.1 Detailed Input Data Assumptions

5.1.1 HISTORICAL 2019 BENCHMARK ASSUMPTIONS

5.1.1.1 BHE Load Assumptions

BHE's historical load was represented in the PLEXOS model using four load profiles – one for each stage that was modeled. BHE provided its DA load forecast and realized RT 5-minute (RT5). E3 developed HA and RT 15-minute (RT15) profiles using actual DA to real-time forecast error from the data BHE provided.

5.1.1.2 BHE Generator Assumptions

For the historical benchmarking case, BHE provided generator characteristics such as generator ratings, minimum-up and -down times, ramp rates, and minimum-run capacity. This data was used to build the PLEXOS historical case model. Table 8 shows the generators that were modeled as part of the historical case.

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Table 8: List of generating units in BHE (historical case)

Category	Name	Rating (MW)
Coal	Neil Simpson 2	80
	Neil Simpson WYGEN 1	65
	Neil Simpson WYGEN 2	90
	Neil Simpson WYGEN 3	103
	Wyodak	68
Natural Gas	CPGS Power Block 1	95
	CPGS Unit 02A	37
	Lange 1	39
	Neil Simpson 1	39
	Ben French CT 1	20
	Ben French CT 2	20
	Ben French CT 3	20
	Ben French CT 4	20
Diesel	Ben French Diesel 1	2
	Ben French Diesel 2	2
	Ben French Diesel 3	2
	Ben French Diesel 4	2
	Ben French Diesel 5	2
Wind	Happy Jack	29
	Silver Sage	42

BHE also provided cost characteristics including unit heat rates, variable O&M and startup costs for certain units, which can be used to determine marginal dispatch cost of generators.

5.1.1.3 Fuel Price Assumptions

BHE provided fuel prices for the historical case. BHE's thermal units consisted of coal and natural gas-fired generators. The mean fuel prices are shown in Table 9.

Table 9: Mean fuel price (historical case)

Category	Mean Fuel Price ($/MMBtu)
Coal	0.87
Natural Gas	2.13
Distillate	11.36

5.1.1.4 Market Price Assumptions

Historical DA and HA prices were obtained from BHE. These were typically in the form of Heavy Load Hour (HLH) and Light Load Hour (LLH) prices for each day. Prices in real-time stages (RT5 and RT15) for the historical EIM case were populated with actual CAISO EIM prices (from OASIS). Figure 9 shows the duration curves for these prices.

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Figure 9: Price duration curves (historical case)

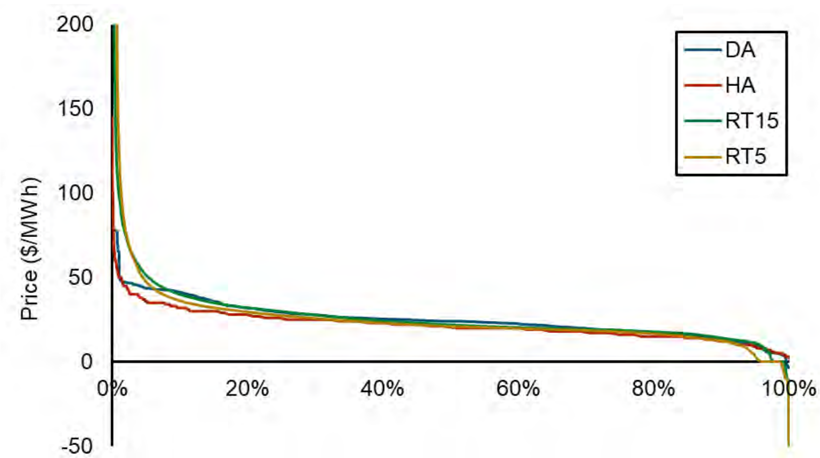

Table 10 shows the minimum, average, and maximum prices for the different stages modeled in the PLEXOS historical case. While on average, real-time market prices were similar to DA and HA price levels, negative prices manifested in real-time markets. As expected, the maximum price in RT markets was also higher than the DA & HA markets.

Table 10: Energy prices (historical case)

Prices ($/MWh)	DA	HA	RT15	RT5
Minimum	$ (3)	$ 2	$ (72)	$ (132)
Average	$ 25	$ 22	$ 27	$ 28
Maximum	$ 79	$ 145	$ 1,000	$ 1,000

5.1.1.5 WACM Representation

WACM's load profiles and generator characteristics were obtained from a TEPPC Database and updated using the S&P Global database. WACM's average load was around 2,100MW and peak was around 3,300MW. WACM's generation mix is shown in Table 11.

Table 11: List of generating units in WACM (historical case)

Category	Capacity (MW)
Coal	4,362
Natural Gas	996
Oil	93
Hydro	1,299
Pumped Hydro	230
Solar	191
Wind	472

5.1.2 FUTURE 2025 SCENARIOS ASSUMPTIONS

5.1.2.1 BHE Load Assumptions

As with the historical case, load was represented using load profiles for each stage that was modeled in PLEXOS. E3 received hourly load forecasts from BHE for the 2025 future year. E3 used the normalized load shapes for the four stages from the 2019 historical case and scaled the shapes to meet the 2025 forecasts provided by BHE.

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5.1.2.2 BHE Generator Assumptions

Compared to the list of generators in the 2019 historical case, the future year scenario included two additional renewable projects. One was a 53MW wind project Coridel. The other was an 80MW solar project Fall River. BHE provided the hourly renewable generation profiles for these two projects. E3 created real-time profiles using historical forecast error in renewable generation.

5.1.2.3 Fuel Price Assumptions

Coal, natural gas, and distillate oil price forecasts were provided by BHE and Hitachi ABB Power Grids' Spring 2020 Power Reference Case. The mean fuel prices are shown in Table 12.

Table 12: Mean fuel price (2025)

Category	Mean Fuel Price ($/MMBtu)
Coal	1.10
Natural Gas	3.95
Distillate	14.85

5.1.2.4 Market Price Assumptions

The DA market prices were provided by BHE and Hitachi ABB Power Grids' Spring 2020 Power Reference Case. These hourly forecasted ahead prices were then combined with historical prices to create future price forecast for different stages. Specifically, the 2025 HA and RT prices were developed by scaling the 2019 prices with the ratio between 2025 and 2019 DA prices. The maximum EIM prices were set at $1,000/MWh. The duration curves are shown in Figure 10.

Figure 10: Price duration curves (2025)

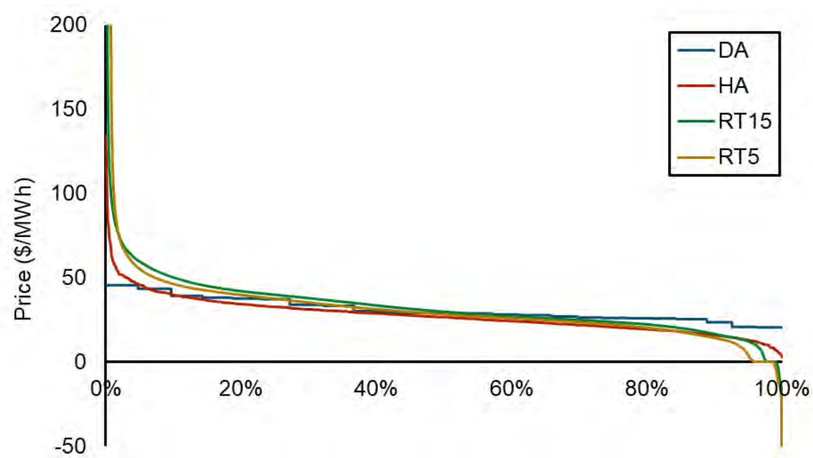

Table 13: Energy Prices (2025)

Prices ($/MWh)	DA	HA	RT15	RT5
Minimum	$ 21	$ 3	$ (109)	$ (185)
Average	$ 31	$ 28	$ 34	$ 35
Maximum	$ 46	$ 135	$ 1,000	$ 1,000

In the future case, market prices on average were higher than historical averages by about 25%.

5.1.2.5 WACM Representation

WACM's load was assumed to grow at a rate of 1% YoY. In the 2025 scenario, the average load was around 2,200MW and peak was around

3,500MW. In terms of the generation fleet in WACM, Table 14 shows resource additions and retirements since 2019 that were considered in the future case. These retirements assume an early retirement of Craig 1 which is due to come offline December 2025 but has been retired before January 2025 for the purposes of this study.

Table 14: Resource retirement and addition in WACM (2025)

Category	Retired Capacity (MW)	Added Capacity (MW)
Coal	610	
Wind		1,728
Solar		60

5.2 Detailed Modeling Results

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5.2.1 HISTORICAL 2019 BENCHMARK RESULTS

5.2.1.1 *EIM Benefits*

	BAU					EIM					EIM-BAU				
Resource	Capacity Factors (%)	Total Generation Cost ($MM/year)	Total Generation (GWh)	No. of Starts	Average Cost ($/MWh)	Capacity Factors (%)	Total Generation Cost ($MM/year)	Total Generation (GWh)	No. of Starts	Average Cost ($/MWh)	Capacity Factors (%)	Total Generation Cost ($MM/year)	Total Generation (GWh)	No. of Starts	Average Cost ($/MWh)
Neil Simpson 2	76%	$ 7.9	535	-	$ 15	94%	$ 9.9	658	-	$ 15	18%	$ 1.9	124	-	$ 0
Neil Simpson WYGEN 1	76%	$ 6.6	569	-	$ 12	75%	$ 6.5	560	-	$ 12	-1%	$ (0.1)	(8)	-	$ 0
Neil Simpson WYGEN 2	93%	$ 9.8	737	-	$ 13	96%	$ 10.1	755	-	$ 13	2%	$ 0.2	18	-	$ 0
Neil Simpson WYGEN 3	96%	$ 10.7	870	-	$ 12	96%	$ 10.7	869	-	$ 12	0%	$ (0.0)	(1)	-	$ 0
Wyodak 1	73%	$ 5.2	435	-	$ 12	73%	$ 5.2	435	-	$ 12	0%	$ -	-	-	$ -
CPGS Power Block 1	76%	$ 11.2	635	-	$ 18	93%	$ 13.5	776	-	$ 17	17%	$ 2.2	141	-	$ (0)
Ben French CT 1	2%	$ 0.3	4	332	$ 63	8%	$ 0.5	17	332	$ 31	6%	$ 0.3	13	-	$ (32)
Ben French CT 2	1%	$ 0.2	3	295	$ 59	6%	$ 0.4	14	295	$ 28	5%	$ 0.2	11	-	$ (31)
Ben French CT 3	2%	$ 0.3	4	302	$ 61	8%	$ 0.5	17	302	$ 30	6%	$ 0.3	13	-	$ (31)
Ben French CT 4	2%	$ 0.2	3	320	$ 67	6%	$ 0.4	13	320	$ 33	4%	$ 0.2	10	-	$ (34)
CPGS Unit 02A	7%	$ 0.5	22	125	$ 21	59%	$ 4.0	192	374	$ 21	53%	$ 3.6	171	249	$ (0)
Lange CT 1	11%	$ 0.8	36	384	$ 22	62%	$ 4.3	211	921	$ 20	51%	$ 3.5	175	537	$ (1)
Neil Simpson CT 1	21%	$ 1.6	71	633	$ 22	63%	$ 4.4	216	910	$ 20	42%	$ 2.8	145	277	$ (2)
Ben French Diesel 1	0%	$ 0.0	0	47	$ 209	1%	$ 0.0	0	140	$ 187	1%	$ 0.0	0	93	$ (22)
Ben French Diesel 2	0%	$ 0.0	0	50	$ 213	1%	$ 0.0	0	139	$ 187	1%	$ 0.0	0	89	$ (26)
Ben French Diesel 3	0%	$ 0.0	0	37	$ 204	1%	$ 0.0	0	140	$ 187	1%	$ 0.0	0	103	$ (17)
Ben French Diesel 4	0%	$ 0.0	0	48	$ 217	1%	$ 0.0	0	139	$ 187	1%	$ 0.0	0	91	$ (30)
Ben French Diesel 5	0%	$ 0.0	0	46	$ 215	1%	$ 0.0	0	139	$ 187	1%	$ 0.0	0	93	$ (28)
Happy Jack Wind	32%	$ -	81	-	$ -	32%	$ -	81	-	$ -	0%	$ -	-	-	$ -
Silver Sage Wind	44%	$ -	161	-	$ -	44%	$ -	161	-	$ -	0%	$ -	-	-	$ -
Total BHE Generation		$ 55.3	4,167				$ 70.5	4,978				$ 15.3	811		
DA/HA Purchases		$ 9.8	465		$ 21		$ 9.8	465	-	$ 21		$ -	-		$ -
RT15 Purchases		$ -	-		$ -		$ 1.0	99	-	$ 10		$ 1.0	99		$ 10
RT5 Purchases		$ -	-		$ -		$ 0.6	59	-	$ 9		$ 0.6	59		$ 9
DA/HA Sales		$ (13.3)	(462)		$ 29		$ (13.3)	(462)	-	$ 29		$ -	-		$ -
RT15 Sales		$ -	-		$ -		$ (24.2)	(809)	-	$ 30		$ (24.2)	(809)		$ 30
RT5 Sales		$ -	-		$ -		$ (5.5)	(161)	-	$ 34		$ (5.5)	(161)		$ 34
Total BHE Production Cost		**$ 51.7**	**4,171**				**$ 38.8**	**4,170**				**$ (12.9)**	**(1)**		

5.2.1.2 EIS Benefits

	BAU					EIS					EIS-BAU				
Resource	Capacity Factors (%)	Total Generation Cost ($MM/year)	Total Generation (GWh)	No. of Starts	Average Cost ($/MWh)	Capacity Factors (%)	Total Generation Cost ($MM/year)	Total Generation (GWh)	No. of Starts	Average Cost ($/MWh)	Capacity Factors (%)	Total Generation Cost ($MM/year)	Total Generation (GWh)	No. of Starts	Average Cost ($/MWh)
Neil Simpson 2	76%	$ 7.9	535	-	$ 15	98%	$ 10.3	685	-	$ 15	21%	$ 2.3	150	-	$ 0
Neil Simpson WYGEN 1	76%	$ 6.6	569	-	$ 12	76%	$ 6.6	569	-	$ 12	0%	$ 0.0	1	-	$ (0)
Neil Simpson WYGEN 2	93%	$ 9.8	737	-	$ 13	100%	$ 10.4	788	-	$ 13	6%	$ 0.6	51	-	$ (0)
Neil Simpson WYGEN 3	96%	$ 10.7	870	-	$ 12	100%	$ 11.1	902	-	$ 12	4%	$ 0.4	32	-	$ (0)
Wyodak 1	73%	$ 5.2	435	-	$ 12	73%	$ 5.2	435	-	$ 12	0%	$ -	-	-	$ -
CPGS Power Block 1	76%	$ 11.2	635	-	$ 18	98%	$ 14.0	817	-	$ 17	22%	$ 2.8	182	-	$ (1)
Ben French CT 1	2%	$ 0.3	4	332	$ 63	6%	$ 0.4	13	332	$ 34	4%	$ 0.2	9	-	$ (29)
Ben French CT 2	1%	$ 0.2	3	295	$ 59	4%	$ 0.3	9	295	$ 32	3%	$ 0.1	6	-	$ (27)
Ben French CT 3	2%	$ 0.3	4	302	$ 61	6%	$ 0.4	12	302	$ 34	4%	$ 0.2	8	-	$ (27)
Ben French CT 4	2%	$ 0.2	3	320	$ 67	4%	$ 0.4	10	320	$ 37	3%	$ 0.1	6	-	$ (31)
CPGS Unit 02A	7%	$ 0.5	22	125	$ 21	39%	$ 2.5	125	172	$ 20	32%	$ 2.0	104	47	$ (2)
Lange CT 1	11%	$ 0.8	36	384	$ 22	44%	$ 2.9	151	459	$ 19	34%	$ 2.1	115	75	$ (3)
Neil Simpson CT 1	21%	$ 1.6	71	633	$ 22	50%	$ 3.2	169	467	$ 19	29%	$ 1.7	98	(166)	$ (3)
Ben French Diesel 1	0%	$ 0.0	0	47	$ 209	0%	$ 0.0	0	9	$ 135	0%	$ (0.0)	(0)	(38)	$ (74)
Ben French Diesel 2	0%	$ 0.0	0	50	$ 213	0%	$ 0.0	0	9	$ 134	0%	$ (0.0)	(0)	(41)	$ (79)
Ben French Diesel 3	0%	$ 0.0	0	37	$ 204	0%	$ 0.0	0	9	$ 134	0%	$ (0.0)	0	(28)	$ (70)
Ben French Diesel 4	0%	$ 0.0	0	48	$ 217	0%	$ 0.0	0	9	$ 134	0%	$ (0.0)	0	(39)	$ (83)
Ben French Diesel 5	0%	$ 0.0	0	46	$ 215	0%	$ 0.0	0	9	$ 134	0%	$ (0.0)	0	(37)	$ (81)
Happy Jack Wind	32%	$ -	81	-	$ -	32%	$ -	81	-	$ -	0%	$ -	-	-	$ -
Silver Sage Wind	44%	$ -	161	-	$ -	44%	$ -	161	-	$ -	0%	$ -	-	-	$ -
Total BHE Generation		$ 55.3	4,167				$ 67.7	4,929				$ 12.5	762		
DA/HA Purchases		$ 9.8	465		$ 21		$ 9.8	465		$ 21		$ -	-		$ -
RT15 Purchases		$ -	-		$ -		$ 0.5	29		$ 16		$ 0.5	29		$ 16
RT5 Purchases		$ -	-		$ -		$ 0.1	3		$ 19		$ 0.1	3		$ 19
DA/HA Sales		$ (13.3)	(462)		$ 29		$ (13.3)	(462)		$ 29		$ -	-		$ -
RT15 Sales		$ -	-		$ -		$ (13.0)	(621)		$ 21		$ (13.0)	(621)		$ 21
RT5 Sales		$ -	-		$ -		$ (4.0)	(174)		$ 23		$ (4.0)	(174)		$ 23
Total BHE Production Cost		**$ 51.7**	**4,171**				**$ 47.7**	**4,170**				**$ (4.0)**	**(1)**		

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5.2.2 FUTURE 2025 SCENARIOS RESULTS

5.2.2.1 EIM Benefits

Resource	BAU Capacity Factors (%)	BAU Total Generation Cost ($MM/year)	BAU Total Generation (GWh)	BAU No. of Starts	BAU Average Cost ($/MWh)	EIM Capacity Factors (%)	EIM Total Generation Cost ($MM/year)	EIM Total Generation (GWh)	EIM No. of Starts	EIM Average Cost ($/MWh)	EIM-BAU Capacity Factors (%)	EIM-BAU Total Generation Cost ($MM/year)	EIM-BAU Total Generation (GWh)	EIM-BAU No. of Starts	EIM-BAU Average Cost ($/MWh)
Neil Simpson 2	75%	$ 9.0	526	-	$ 17	95%	$ 11.4	662	-	$ 17	19%	$ 2.4	136	-	$ 0
Neil Simpson WYGEN 1	75%	$ 8.6	559	-	$ 15	75%	$ 8.6	559	-	$ 15	0%	$ 0.0	(0)	-	$ 0
Neil Simpson WYGEN 2	88%	$ 10.6	696	-	$ 15	96%	$ 11.5	756	-	$ 15	8%	$ 0.9	59	-	$ (0)
Neil Simpson WYGEN 3	92%	$ 11.7	829	-	$ 14	96%	$ 12.2	869	-	$ 14	4%	$ 0.6	40	-	$ 0
Wyodak 1	73%	$ 5.2	435	-	$ 12	73%	$ 5.2	435	-	$ 12	0%	$ -	-	-	$ -
CPGS Power Block 1	56%	$ 15.2	465	174	$ 33	79%	$ 20.1	657	174	$ 31	23%	$ 4.9	193	-	$ (2)
Ben French CT 1	1%	$ 0.4	3	174	$ 127	2%	$ 0.5	5	174	$ 92	1%	$ 0.1	2	-	$ (35)
Ben French CT 2	1%	$ 0.2	2	135	$ 125	2%	$ 0.3	4	135	$ 82	1%	$ 0.1	2	-	$ (43)
Ben French CT 3	1%	$ 0.2	2	139	$ 126	2%	$ 0.3	4	139	$ 81	1%	$ 0.1	2	-	$ (45)
Ben French CT 4	1%	$ 0.3	2	137	$ 125	2%	$ 0.4	4	137	$ 84	1%	$ 0.1	2	-	$ (41)
CPGS Unit 02A	4%	$ 0.5	12	90	$ 42	32%	$ 4.0	103	576	$ 39	28%	$ 3.5	91	486	$ (2)
Lange CT 1	1%	$ 0.2	4	62	$ 42	23%	$ 3.3	79	954	$ 42	22%	$ 3.1	75	892	$ (1)
Neil Simpson CT 1	5%	$ 0.7	16	385	$ 45	25%	$ 3.5	84	1,039	$ 41	20%	$ 2.8	68	654	$ (3)
Ben French Diesel 1	2%	$ 0.1	0	316	$ 235	1%	$ 0.1	0	157	$ 225	-1%	$ (0.0)	(0)	(159)	$ (10)
Ben French Diesel 2	2%	$ 0.1	0	319	$ 236	1%	$ 0.1	0	157	$ 225	-1%	$ (0.0)	(0)	(162)	$ (11)
Ben French Diesel 3	2%	$ 0.1	0	306	$ 236	1%	$ 0.1	0	157	$ 225	-1%	$ (0.0)	(0)	(149)	$ (12)
Ben French Diesel 4	2%	$ 0.1	0	282	$ 232	1%	$ 0.1	0	157	$ 225	-1%	$ (0.0)	(0)	(125)	$ (7)
Ben French Diesel 5	2%	$ 0.1	0	313	$ 234	1%	$ 0.1	0	157	$ 225	-1%	$ (0.0)	(0)	(156)	$ (10)
Happy Jack Wind	32%	$ -	81	-	$ -	32%	$ -	81	-	$ -	0%	$ -	-	-	$ -
Silver Sage Wind	44%	$ -	161	-	$ -	44%	$ -	161	-	$ -	0%	$ -	-	-	$ -
Coridel Wind	39%	$ -	179	-	$ -	39%	$ -	179	-	$ -	0%	$ -	-	-	$ -
Fall River Solar	27%	$ -	188	-	$ -	27%	$ -	188	-	$ -	0%	$ -	-	-	$ -
Total BHE Generation		$ 63.2	4,162				$ 81.5	4,831				$ 18.3	669		
DA/HA Purchases		$ 19.7	697		$ 28		$ 19.7	697		$ 28		$ -	-		$ -
RT15 Purchases		$ -	-		$ -		$ 0.7	51		$ 14		$ 0.7	51		$ 14
RT5 Purchases		$ -	-		$ -		$ 2.9	127		$ 23		$ 2.9	127		$ 23
DA/HA Sales		$ (11.4)	(334)		$ 34		$ (11.4)	(334)		$ 34		$ -	-		$ -
RT15 Sales		$ -	-		$ -		$ (33.8)	(796)		$ 42		$ (33.8)	(796)		$ 42
RT5 Sales		$ -	-		$ -		$ (2.5)	(54)		$ 46		$ (2.5)	(54)		$ 46
Total BHE Production Cost		**$ 71.5**	**4,525**				**$ 57.2**	**4,523**				**$ (14.3)**	**(2)**		

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Black Hills Energy Ready

5.2.2.2 EIS Benefits

	BAU					EIS					EIS-BAU				
Resource	Capacity Factors (%)	Total Generation Cost ($MM/year)	Total Generation (GWh)	No. of Starts	Average Cost ($/MWh)	Capacity Factors (%)	Total Generation Cost ($MM/year)	Total Generation (GWh)	No. of Starts	Average Cost ($/MWh)	Capacity Factors (%)	Total Generation Cost ($MM/year)	Total Generation (GWh)	No. of Starts	Average Cost ($/MWh)
Neil Simpson 2	75%	$ 9.0	526	-	$ 17	99%	$ 11.9	692	-	$ 17	24%	$ 2.9	166	-	$ 0
Neil Simpson WYGEN 1	75%	$ 8.6	559	-	$ 15	76%	$ 8.7	568	-	$ 15	1%	$ 0.1	9	-	$ (0)
Neil Simpson WYGEN 2	88%	$ 10.6	696	-	$ 15	100%	$ 11.9	786	-	$ 15	11%	$ 1.3	89	-	$ (0)
Neil Simpson WYGEN 3	92%	$ 11.7	829	-	$ 14	100%	$ 12.6	900	-	$ 14	8%	$ 1.0	71	-	$ (0)
Wyodak 1	73%	$ 5.2	435	-	$ 12	73%	$ 5.2	435	-	$ 12	0%	$ -	-	-	$ -
CPGS Power Block 1	56%	$ 15.2	465	174	$ 33	75%	$ 19.3	626	174	$ 31	19%	$ 4.1	162	-	$ (2)
Ben French CT 1	1%	$ 0.4	3	174	$ 127	1%	$ 0.4	3	174	$ 127	0%	$ 0.0	0	-	$ (0)
Ben French CT 2	1%	$ 0.2	2	135	$ 125	1%	$ 0.2	2	135	$ 124	0%	$ 0.0	0	-	$ (1)
Ben French CT 3	1%	$ 0.2	2	139	$ 126	1%	$ 0.2	2	139	$ 123	0%	$ 0.0	0	-	$ (3)
Ben French CT 4	1%	$ 0.3	2	137	$ 125	1%	$ 0.3	2	137	$ 125	0%	$ 0.0	0	-	$ (1)
CPGS Unit 02A	4%	$ 0.5	12	90	$ 42	2%	$ 0.3	6	77	$ 43	-2%	$ (0.2)	(6)	(13)	$ 1
Lange CT 1	1%	$ 0.2	4	62	$ 42	1%	$ 0.1	3	90	$ 44	0%	$ (0.0)	(1)	28	$ 1
Neil Simpson CT 1	5%	$ 0.7	16	385	$ 45	3%	$ 0.5	10	328	$ 45	-2%	$ (0.3)	(6)	(57)	$ 1
Ben French Diesel 1	2%	$ 0.1	0	316	$ 235	0%	$ 0.0	0	29	$ 191	-2%	$ (0.1)	(0)	(287)	$ (44)
Ben French Diesel 2	2%	$ 0.1	0	319	$ 236	0%	$ 0.0	0	24	$ 187	-2%	$ (0.1)	(0)	(295)	$ (49)
Ben French Diesel 3	2%	$ 0.1	0	306	$ 236	0%	$ 0.0	0	24	$ 187	-2%	$ (0.1)	(0)	(282)	$ (49)
Ben French Diesel 4	2%	$ 0.1	0	282	$ 232	0%	$ 0.0	0	29	$ 191	-2%	$ (0.1)	(0)	(253)	$ (41)
Ben French Diesel 5	2%	$ 0.1	0	313	$ 234	0%	$ 0.0	0	24	$ 187	-2%	$ (0.1)	(0)	(289)	$ (47)
Happy Jack Wind	32%	$ -	81	-	$ -	32%	$ -	81	-	$ -	0%	$ -	-	-	$ -
Silver Sage Wind	44%	$ -	161	-	$ -	44%	$ -	161	-	$ -	0%	$ -	-	-	$ -
Coridel Wind	39%	$ -	179	-	$ -	39%	$ -	179	-	$ -	0%	$ -	-	-	$ -
Fall River Solar	27%	$ -	188	-	$ -	27%	$ -	188	-	$ -	0%	$ -	-	-	$ -
Total BHE Generation		$ 63.2	4,162				$ 71.7	4,644				$ 8.5	482		
DA/HA Purchases		$ 19.7	697		$ 28		$ 19.7	697		$ 28		$ -	-		$ -
RT15 Purchases		$ -	-		$ -		$ 0.5	35		$ 14		$ 0.5	35		$ 14
RT5 Purchases		$ -	-		$ -		$ 1.3	52		$ 25		$ 1.3	52		$ 25
DA/HA Sales		$ (11.4)	(334)		$ 34		$ (11.4)	(334)		$ 34		$ -	-		$ -
RT15 Sales		$ -	-		$ -		$ (14.3)	(521)		$ 27		$ (14.3)	(521)		$ 27
RT5 Sales		$ -	-		$ -		$ (1.3)	(50)		$ 27		$ (1.3)	(50)		$ 27
Total BHE Production Cost		**$ 71.5**	**4,525**				**$ 66.2**	**4,523**				**$ (5.3)**	**(2)**		

5.2.2.3 EIS Benefits 5 minute stage only

	BAU					EIS					EIS-BAU				
Resource	Capacity Factors (%)	Total Generation Cost ($MM/year)	Total Generation (GWh)	No. of Starts	Average Cost ($/MWh)	Capacity Factors (%)	Total Generation Cost ($MM/year)	Total Generation (GWh)	No. of Starts	Average Cost ($/MWh)	Capacity Factors (%)	Total Generation Cost ($MM/year)	Total Generation (GWh)	No. of Starts	Average Cost ($/MWh)
Neil Simpson 2	75%	$ 9.0	526	-	$ 17	99%	$ 11.9	692	-	$ 17	24%	$ 2.9	166	-	$ 0
Neil Simpson WYGEN 1	75%	$ 8.6	559	-	$ 15	76%	$ 8.7	568	-	$ 15	1%	$ 0.1	9	-	$ (0)
Neil Simpson WYGEN 2	88%	$ 10.6	696	-	$ 15	100%	$ 11.9	785	-	$ 15	11%	$ 1.3	89	-	$ (0)
Neil Simpson WYGEN 3	92%	$ 11.7	829	-	$ 14	100%	$ 12.6	899	-	$ 14	8%	$ 1.0	71	-	$ (0)
Wyodak 1	73%	$ 5.2	435	-	$ 12	73%	$ 5.2	435	-	$ 12	0%	$ -	-	-	$ -
CPGS Power Block 1	56%	$ 15.2	465	174	$ 33	75%	$ 19.3	626	174	$ 31	19%	$ 4.1	162	-	$ (2)
Ben French CT 1	1%	$ 0.4	3	174	$ 127	1%	$ 0.4	3	174	$ 128	0%	$ (0.0)	(0)	-	$ 1
Ben French CT 2	1%	$ 0.2	2	135	$ 125	1%	$ 0.2	2	135	$ 125	0%	$ 0.0	0	-	$ 0
Ben French CT 3	1%	$ 0.2	2	139	$ 126	1%	$ 0.2	2	139	$ 125	0%	$ 0.0	0	-	$ (1)
Ben French CT 4	1%	$ 0.3	2	137	$ 125	1%	$ 0.3	2	137	$ 125	0%	$ 0.0	0	-	$ (0)
CPGS Unit 02A	4%	$ 0.5	12	90	$ 42	4%	$ 0.5	12	90	$ 41	0%	$ 0.0	0	-	$ (0)
Lange CT 1	1%	$ 0.2	4	62	$ 42	1%	$ 0.1	3	62	$ 44	0%	$ (0.0)	(0)	-	$ 1
Neil Simpson CT 1	5%	$ 0.7	16	385	$ 45	5%	$ 0.7	16	385	$ 45	0%	$ (0.0)	(0)	-	$ 0
Ben French Diesel 1	2%	$ 0.1	0	316	$ 235	1%	$ 0.0	0	38	$ 196	-2%	$ (0.1)	(0)	(278)	$ (39)
Ben French Diesel 2	2%	$ 0.1	0	319	$ 236	0%	$ 0.0	0	32	$ 191	-2%	$ (0.1)	(0)	(287)	$ (44)
Ben French Diesel 3	2%	$ 0.1	0	306	$ 236	0%	$ 0.0	0	32	$ 191	-2%	$ (0.1)	(0)	(274)	$ (45)
Ben French Diesel 4	2%	$ 0.1	0	282	$ 232	1%	$ 0.0	0	37	$ 194	-2%	$ (0.1)	(0)	(245)	$ (37)
Ben French Diesel 5	2%	$ 0.1	0	313	$ 234	0%	$ 0.0	0	32	$ 191	-2%	$ (0.1)	(0)	(281)	$ (43)
Happy Jack Wind	32%	$ -	81	-	$ -	32%	$ -	81	-	$ -	0%	$ -	-	-	$ -
Silver Sage Wind	44%	$ -	161	-	$ -	44%	$ -	161	-	$ -	0%	$ -	-	-	$ -
Coridel Wind	39%	$ -	179	-	$ -	39%	$ -	179	-	$ -	0%	$ -	-	-	$ -
Fall River Solar	27%	$ -	188	-	$ -	27%	$ -	188	-	$ -	0%	$ -	-	-	$ -
Total BHE Generation		$ 63.2	4,162				$ 72.2	4,656				$ 9.0	494		
DA/HA Purchases		$ 19.7	697		$ 28		$ 19.7	697		$ 28		$ -	-		$ -
RT15 Purchases		$ -	-		$ -		$ -	-		$ -		$ -	-		$ -
RT5 Purchases		$ -	-		$ -		$ 0.2	12		$ 13		$ 0.2	12		$ 13
DA/HA Sales		$ (11.4)	(334)		$ 34		$ (11.4)	(334)		$ 34		$ -	-		$ -
RT15 Sales		$ -	-		$ -		$ -	-		$ -		$ -	-		$ -
RT5 Sales		$ -	-		$ -		$ (14.3)	(508)		$ 28		$ (14.3)	(508)		$ 28
Total BHE Production Cost		**$ 71.5**	**4,525**				**$ 66.4**	**4,523**				**$ (5.2)**	**(2)**		

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J. LOAD AND RESOURCE BALANCE 2021—2040

This appendix contains three load and resource balances tables: one for Cheyenne Light, one for Black Hills Power, and one for both utilities jointly. These balances compare annual peak demand with the capacity contribution of existing resources over the entire planning period: 2021 through 2040.

The load and resource balances highlight the years in which forecasted demand exceeds resources, thus indicating a need for additional capacity. All three load and resource balances consider the 15 percent planning reserve margin requirement.

Black Hills Power Load and Resources Balance - 2021–2040

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
PEAK DEMAND[1]																				
Black Hills Power Native Load	372	375	377	379	377	377	380	383	385	387	389	390	392	393	395	396	397	399	400	401
yearly % change		0.8%	0.5%	0.7%	-0.6%	0.0%	0.9%	0.7%	0.7%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.3%	0.3%	0.3%	0.3%
EXISTING RESOURCES[1]																				
Neil Simpson Unit II	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Wyodak	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	
Ben French Diesels	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Ben French CTs	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Lange CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Neil Simpson CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Wygen III	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
CPGS CC	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Corriedale (32.5 MW)[2]	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Total Existing Resources	418	418	418	418	418	418	418	418	418	418	418	418	418	418	418	418	418	418	418	356
PURCHASE																				
Colstrip	50	50	50																	
Happy Jack[2]	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4												
Silver Sage[2]	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8											
Wind Contract (12 MW)[2]	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5											
Fall River Solar (80 MW)[3]			8.8	8.8	8.7	8.7	8.6	8.6	8.5	8.5	8.5	8.4	8.4	8.3	8.3	8.2	8.2	8.2	8.1	8.1
Total Purchases	64	64	72	22	22	22	22	22	18	8	8	8	8	8	8	8	8	8	8	8
SALES																				
MEAN Contract	15	15	10	10	10	10	10													
MDU All-Requirements	40	41	42	43	44	45	46	47												
COG All-Requirements	15	16																		
Total Sales	70	72	52	53	54	55	56	47	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL RESOURCES-SALES	412	410	439	388	387	386	385	394	436	427	427	427	427	427	427	427	427	427	427	365
COG NS CT II (40 MW Planning Reserve)	40	40																		
MDU Wygen III Ownership (25 MW Planning Reserve)	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
COG Wygen III Ownership (23 MW Planning Reserve)	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
MDU Planning Reserves	9	8	7	6	5	4	3	2	4	4	4	4	4	4	4	4	4	4	4	4
TOTAL PLANNING RESERVES	76	76	67	66	65	64	64	63	65	65	65	66	66	66	66	67	67	67	67	67
PEAK PLUS RESERVES	448	450	443	445	442	441	444	446	450	452	454	456	458	459	461	463	464	466	467	469
CAPACITY EXCESS/DEFICIT (MW)	-36	-41	-5	-58	-55	-55	-59	-52	-14	-25	-27	-29	-31	-33	-34	-36	-38	-39	-41	-104
CAPACITY EXCESS/DEFICIT (%)	-8%	-9%	-1%	-13%	-13%	-13%	-13%	-12%	-3%	-6%	-6%	-6%	-7%	-7%	-7%	-8%	-8%	-8%	-9%	-22%

1: Peak demand is forecasted summer peak and resource capacities are summer ratings coresponding to the peak day.
2: 29% of Happy Jack, Silver Sage, and Corriedale's capacites count as accredited capacity.
3: 11% of Fall River's capacity counts as accredited capacity.

Table J-1. Cheyenne Light Load and Resource Balance: 2021–2030

Cheyenne Light Load and Resources Balance - 2021–2040

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
PEAK DEMAND[1]																				
Cheyenne Light Native Load	215	224	225	226	225	229	231	233	234	236	238	239	241	242	244	245	247	248	250	251
yearly % change		4.1%	0.7%	0.3%	-0.5%	2.0%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
PLANNING RESERVE (15%)	32	34	34	34	34	34	35	35	35	35	36	36	36	36	37	37	37	37	37	38
PEAK plus RESERVES	247	257	259	260	259	264	266	268	270	271	273	275	277	279	280	282	284	286	287	289
EXISTING RESOURCES and CONTRACTS[1]																				
Wygen II	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
CPGS SC	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
CPGS CC	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Wygen 1 Current PPA	60																			
Wygen 1 New PPA		60	60	60	60	60	60	60	60	60	60	60								
Happy Jack[2]	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4												
Silver Sage[2]	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9											
Corriedale[2]	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
TOTAL EXISTING CAPACITY	240	240	240	240	240	240	240	240	236	233	233	233	173	173	173	173	173	173	173	173
PEAK plus RESERVES	247	257	259	260	259	264	266	268	270	271	273	275	277	279	280	282	284	286	287	289
CAPACITY EXCESS/(DEFICIT) MW	(7)	(17)	(19)	(20)	(19)	(24)	(26)	(28)	(34)	(39)	(41)	(42)	(104)	(106)	(108)	(109)	(111)	(113)	(115)	(116)
CAPACITY EXCESS/DEFICIT %	-3%	-7%	-7%	-8%	-7%	-9%	-10%	-10%	-13%	-14%	-15%	-15%	-38%	-38%	-38%	-39%	-39%	-40%	-40%	-40%

1: Peak demand is forecasted summer peak and resource capacities are summer ratings corresponding to the peak day.
2: 29% of Happy Jack, Silver Sage, and Corriedale's capacities counts as accredited capacities.

Table J-2. Black Hills Power Load and Resource Balance: 2021–2030

Joint Load and Resources Balance - 2021–2040																				
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
PEAK DEMAND*																				
Black Hills Power Native Load	372	375	377	379	377	377	380	383	385	387	389	390	392	393	395	396	397	399	400	401
Cheyenne Light Load	215	224	225	226	225	229	231	233	234	236	238	239	241	242	244	245	247	248	250	251
Coincident Joint Peak Load	543	543	544	567	577	562	565	552	555	580	600	580	565	566	567	613	591	592	576	576
yearly % change		-0.1%	0.2%	4.2%	1.8%	-2.7%	0.7%	-2.4%	0.5%	4.6%	3.5%	-3.5%	-2.5%	0.1%	0.2%	8.2%	-3.7%	0.3%	-2.8%	-0.1%
EXISTING RESOURCES[1]																				
Neil Simpson Unit II	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Wyodak	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	
Ben French Diesels	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Ben French CTs	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Lange CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Neil Simpson CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Wygen III	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Wygen II	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
CPGS SC	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
CPGS CC	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Corriedale[2]	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2
Total Existing Resources	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	529
PURCHASE																				
Colstrip	50	50	50																	
Wygen I Current PPA	60																			
Wygen I New PPA		60	60	60	60	60	60	60	60	60	60	60								
Happy Jack[2]	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7												
Silver Sage[2]	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7											
Wind Contract (12 MW)[2]	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5											
Fall River Solar (80 MW)[3]			8.8	8.8	8.7	8.7	8.6	8.6	8.5	8.5	8.5	8.4	8.4	8.3	8.3	8.2	8.2	8.2	8.1	8.1
Total Purchases	131	131	140	90	90	90	90	89	81	68	68	68	8	8	8	8	8	8	8	8
SALES																				
MEAN Contract	15	15	10	10	10	10	10													
MDU All-Requirements	40	41	42	43	44	45	46	47												
COG All-Requirements	15	16																		
Total Sales	70	72	52	53	54	55	56	47	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL RESOURCES minus SALES	652	650	679	628	627	626	625	634	672	660	660	660	600	600	600	599	599	599	599	537
COG NS CT II (40 MW Planning Reserve)	40	40																		
MDU Wygen III Ownership (25 MW Planning Reserve)	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
COG Wygen III Ownership (23 MW Planning Reserve)	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
MDU Planning Reserves	9	8	7	6	5	4	3	2	4	4	4	4	4	4	4	4	4	4	4	4
TOTAL PLANNING RESERVES	102	101	92	94	95	92	91	89	90	94	97	94	92	92	92	99	96	96	94	94
PEAK PLUS RESERVES	645	644	636	661	672	653	657	640	645	675	698	674	657	658	659	712	686	689	670	669
CAPACITY EXCESS/DEFICIT (MW)	7	6	43	-34	-45	-28	-32	-6	27	-15	-38	-14	-57	-58	-60	-113	-87	-89	-70	-132
CAPACITY EXCESS/DEFICIT (%)	1%	1%	7%	-5%	-7%	-4%	-5%	-1%	4%	-2%	-5%	-2%	-9%	-9%	-9%	-16%	-13%	-13%	-11%	-20%

1: Peak demand is forecasted summer peak and resource capacities are summer ratings coresponding to the peak day.
2: 29% of Happy Jack, Silver Sage, and Corriedale's capacites count as accredited capacity.
3: 11% of Fall River's capacity counts as accredited capacity.

Table J-3. Cheyenne Light and Black Hills Power Joint Load and Resource Balance: 2021–2030

K. ANALYTICAL METHODS AND MODULES

The 2021 IRP used the Strategic Planning *powered by MIDAS Gold®* package of tools developed by Hitachi ABB Power Grids (HAPG). Strategic Planning includes Financial and Risk modules.

The IRP used the Capacity Expansion module to produce unique resource portfolios across a range of different planning assumptions.

Capacity Expansion's database is used in conjunction with Portfolio Optimization for additional detailed modeling. The system allows resource portfolios created using Capacity Expansion to be used in the Portfolio Optimization solution where hourly chronological simulations provide operational detail.

Over the 20-year planning horizon, the Capacity Expansion model operates by minimizing operating costs for existing and prospective new resources. It optimizes resource additions subject to resource costs, capacity constraints (summer peak loads plus a planning reserve margin), and system reliability. For the planned retirement of an existing generating resource or contract expiration, Capacity Expansion selects additional resources as required to meet peak loads that include the 15 percent planning reserve margin.

To best optimize resource options, Capacity Expansion performs a time-of-day least-cost dispatch for existing and potential planned generation. It bases the resource dispatch on a representative week. Dispatch determines optimal electricity flows between zones and includes spot market transactions for system balancing.

The model minimizes the system PVRR, including:

- Net present value cost of existing contracts.
- Spot market purchase costs.
- Generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity).
- Amortized capital costs for potential new resources.

The IRP used the Portfolio Optimization module to analyze and report the optimal dispatch of the Capacity Expansion generation portfolios against a load requirement. Portfolio Optimization produces optimal operating schedules for the entire portfolio of generation assets and transactions. The module optimizes a portfolio's operation by modeling detailed unit operating constraints and market conditions to provide a generation schedule for energy, ancillary services, and fuel nominations.

Portfolio Optimization results facilitate the analysis and simulation of deterministic and stochastic scenarios. The mixed-integer linear programming optimizes thermal units, combined cycle units, and renewables (including BESS) into a single solution.

The Portfolio Optimization Stochastic Analysis module simulates uncertainties in electric and fuel prices, loads, energy availability, and other factors that could impact the hourly simulation results. This module incorporates a Regression Tool, Draw Generation, and Stochastic Analysis.

The IRP also used Strategic Planning's Financial and Risk modules. The Financial module models costs external to unit operation and other valuable information necessary to thoroughly evaluate the economics of a generation fleet. The module produces bottom-line financial statements to evaluate profitability and earnings impacts. The Risk module performs stochastic analyses on all other modules and reviews results numerically and graphically. Stochastics can be performed on both production and financial variables.

Strategic Planning uses a Latin Hypercube-based stratified sampling program that takes into account statistical distributions, correlations, and volatilities for three time periods—short-term hour, mid-term month, and long-term annual—for each transact group. Stratified sampling can be thought of as "smart" Monte Carlo sampling. Instead of drawing each sample from the entire distribution—as in Monte Carlo sampling—the planning tool divides the sample space into equal probability ranges and then takes a sample from each range.

L. OVERVIEW OF FORECASTING MODELS

This appendix explains and summarizes the long-term energy and demand forecasting models for Cheyenne Light and Black Hills Power.

Long-term energy forecasts use a combination of its billing data, weather data from the National Oceanic and Atmospheric Administration (NOAA), and economic and demographic data from Woods & Poole. Demand forecasts use a combination of hourly system demand data and the same weather, economic, and demographic data.

Forecasts are based on single sales or on separate use-per-customer sales for residential, commercial, industrial, and municipal models. Included are the formulas employed to develop these forecast models.

Overview of Long-Term Energy and Demand Forecasting Models for Black Hills Power, Inc. and Cheyenne Light Fuel and Power Company

for

Black Hills Corporation

by

Christensen Associates Energy Consulting, LLC
800 University Bay Drive, Suite 400
Madison, WI 53705-2299
Voice 608.231.2266 Fax 608.231.2108

April 18, 2021

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Overview of Long-Term Energy and Demand Forecasting Models for Black Hills Power, Inc. and Cheyenne Light Fuel and Power Company

for

Black Hills Corporation

by

CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC

April 18, 2021

1. INTRODUCTION

Christensen Associates Energy Consulting, LLC (CA Energy Consulting) assisted Black Hills Corporation (Black Hills) in developing long-term energy and demand forecasts for Black Hills Power, Inc. and Cheyenne Light Fuel and Power Company. Black Hills is required to file an Integrated Resource Plan (IRP) in Wyoming and South Dakota before July 1, 2021.

Black Hills develops class-specific sales forecasts using a combination of its billing data, weather data from the National Oceanic and Atmospheric Administration (NOAA), and economic and demographic data from Woods & Poole. System demand is forecast using a combination of hourly system demand data with the weather and economic data listed above.

Section 2 provides a description of the principles we apply when developing forecasts. Section 3 describes the models developed for Black Hills Power, Inc. (BHP). Section 4 describes the models developed for Cheyenne Light Fuel and Power Company (CLFP).

2. OVERVIEW OF THE FORECAST DEVELOPMENT PROCESS

Selecting the dependent variable

Statistical forecast models begin by explaining historical variation in a dependent variable (e.g., class-level sales or use per customer (UPC)) with available explanatory variables.

Forecasts may be based on either a single sales model or separate UPC and customer count models. The latter method may be preferred for mass-market classes (e.g., residential), where intra-class customer differences are expected to be minor compared to, say, a large industrial class. Separately modeling UPC and customer counts for these classes can improve the estimates of the effect of the various explanatory variables. For example, the number of households may be a primary driver of the number of residential customers served, but not be strongly related to residential use per customer.

In each of the models presented here, we take the natural log of the dependent variable and the continuous explanatory variables.[1] This makes it easier interpret and compare the estimated coefficients, as they represent percentage effects. If the models were instead estimated without logging the variables, the estimated coefficients would represent *level* effects whose interpretation is affected by the scale of the variables.

Selecting the explanatory variables

The explanatory variables may include the following categories:

- Weather;
- Economic conditions;
- Demographics;
- Seasonal indicators; or
- Time trends or shift variables.

Weather variables are typically based on temperatures and commonly expressed as cooling degree days (CDDs) or heating degree days (HDDs). CDDs are intended to reflect cooling-related usage and are calculated for day *d* as follows:

$$CDD_d = \text{MAX}\{0, (MaxTemp_d + MinTemp_d) / 2 – Threshold)\}$$

The MAX function ensures that CDD values are always non-negative. $MaxTemp_d$ and $MinTemp_d$ represent the maximum and minimum temperatures for the day, respectively. *Threshold* is the average daily temperature at which cooling load tends to begin (typically around 60°F).

HDDs reflect heating-related loads and are calculated in a similar manner as CDDs, but reversing the order of the average daily temperature and the *Threshold*:

$$HDD_d = \text{MAX}\{0, Threshold – (MaxTemp_d + MinTemp_d) / 2)\}$$

Forecasting models often use monthly sales or UPC as the dependent variable, in which case the CDDs and HDDs are summed across the relevant days to form the variables used in the statistical model.

Economic factors reflect the effect of the economy on electricity use or the number of customers served. The relevant variables can vary with the customer class of interest and may include the following variables:

- Household income;
- Gross regional product (GRP); or
- Earnings, sales, or employment (total or by sector).

Demographic variables can reflect changes in the size or makeup of the utility's service territory, and may include the following variables:

- Number of households; or

[1] The exceptions for continuous variables are CDDs and HDDs, which are frequently zero and therefore drop out when logged.

- Persons per household.

Seasonal or monthly factors are "indicator" variables (sometimes called "dummy" variables)[2] that account for seasonal changes in usage that are not accounted for by other included explanatory variables (e.g., lighting-related usage that can vary with the hours of daylight).

Time trend and shift variables are sometimes needed to reflect changes in the dependent variable that are clearly visible in the data but are not explained by any available explanatory variables. For example, this may include changes in the definition of the customer class. Time trend variables reflect the rate of change in the dependent variable over time, while shift variables account for one-time changes in the dependent variable.

Note that any explanatory variable included in the statistical model must have both historical and forecast values to be of use in the development of the forecast. In the case of weather variables, the forecast values typically represent normal weather conditions (e.g., the average value over the previous 20 years). Economic and demographic variables are best employed when external forecasts of them are available. Black Hills uses data from Woods & Poole, which provides historical and forecast values for economic and demographic variables by county.

When evaluating explanatory variables for inclusion in statistical forecast models, we focus on the following factors:

1. Whether the included variables make intuitive sense.
2. Whether the estimated coefficients on the included variables make intuitive sense.
3. Whether the resulting forecast is a reasonable reflection of the past as well as expectations for the future.

Regarding the first point, we consider whether it's plausible that the included economic and/or demographic variables have a causal effect on the dependent variable (e.g., use per customer, sales, or the number of customers). For example, farm employment is probably not going to drive outcomes for a customer class that does not consist of a high share of farm-related customers.

On the second point, the estimates should have the expected sign, a reasonable magnitude, and be statistically significantly different from zero.[3] For example, we expect electricity use, use per customer, and the number of customers to increase as economic conditions improve. That would be reflected by a positive sign on the estimated coefficient on the economic variable.[4]

[2] For example, a March indicator variable would equal 1 for March observations and 0 for all other observations.
[3] This is evaluated using the p-value associated with the estimate, which is based on a test that the estimated coefficient equals zero (the "null hypothesis"). If the estimated coefficient equals zero, it means that changes in the variable do not affect the dependent variable (e.g., sales). A point estimate that is not zero may be statistically equivalent to zero if the standard error associated with the estimate is sufficiently large. A low p-value (below 0.10 or 0.05) leads us to reject the null hypothesis that the variable has no effect.
[4] A negative sign would be expected for economic variables for which higher values represent worsening conditions, such as the unemployment rate.

Demographic changes such as the change in the number of households are also expected to have specific signs. For example, an increase in the number of households should lead to increases in sales and increases in the number of customers served (a positive coefficient). Increases in persons per household may lead to increases in residential use per customer (also a positive coefficient).

Evaluating the magnitude of the coefficient requires some judgment and people may reach different conclusions. Economic variables shouldn't have outsized effects. For example, in models with logged dependent and explanatory variables, estimated coefficients larger than 1.0 mean the percentage change in the dependent variable will be larger than the percentage change in the economic variable (e.g., a 2 percent increase in GRP leads to a greater than 2 percent increase in sales). That threshold is a good starting point for judging the reasonableness of the variable, though the reasonableness of the coefficient may also be apparent in the forecast growth rate (i.e., an economic effect that is too large may lead to a growth rate in electricity sales that appears too high relative to historical rates).

Note that sometimes there are no economic variables that provide an intuitively appealing explanation of the dependent variable. This can arise when sales or use per customer are declining, perhaps due to conservation and improved energy efficiency (whether sponsored by the utility or as part of general economic or regulatory trends). In these cases, a time trend variable can be useful to allow the model to explain changes over time. In some cases, the introduction of a time trend allows the model to be able to estimate a separate and reasonable economic effect, but this is not always the case.

Finally, the model should produce a forecast that is a reasonable reflection of expectations given prior trends and Company information. For example, if sales declined steeply from 8 to 10 years ago but have remained relatively flat in more recent years, one might expect the forecast to place a higher weight on the recent (flat) trend. Applying this criterion involves exercising judgment and isn't necessarily a right vs. wrong issue (in contrast to evaluating the sign of a coefficient).

Accounting for serial correlation

Serial correlation is present when the statistical model's error (the difference between the observed value and the value predicted by the model) in a time period is related to the error in a prior time period. The presence of serial correlation does not produce biased coefficient estimates but may lead to incorrect inferences regarding a coefficient's statistical significance.

The presence of first-order serial correlation (when the current and previous observation's errors are related) is detected using the Durbin-Watson test. If the test indicates that serial correlation is present, we estimate the model using a Prais-Winsten method rather than traditional Ordinary Least Squares (OLS).

Developing High and Low Forecast Scenarios

Black Hills requested that we develop an 80 percent confidence interval around the demand and sales forecasts. That is, the forecast represents the sales and demand levels we expect to occur on average. However, considerable uncertainty remains regarding the economic conditions that will occur during the forecast period. For example, a recession could arise, or a period of sustained growth could occur. The confidence interval provides an indication of the extent to which demand and sales can vary due to such uncertainties.

In order to capture a wide range of economic conditions, we base our variability calculations on data beginning in 1969 and ending with the most recent observed data point. The data are provided by Woods & Poole and focus on the variable used in the forecast models. The variability calculation takes a mid- to long-term perspective, based on the average annual percentage change over ten-year period.

Specifically, we calculate the year-to-year percentage changes in the economic variable (e.g., gross regional product, total employment, or personal income) and then calculate 10-year moving averages of those percentage changes. The peak demand model provides us with an estimate of the effect of changes in the economic variable on changes in peak demand, along with a standard error associated with the estimate. These two uncertainties (in economic conditions over time and in the estimated effect of economic conditions on peak demand) are combined to produce the confidence interval around the demand and sales forecasts.

Here is a description of the steps we used to develop the confidence interval:

1. Calculate the average annual 10-year percentage change in the economic variable for each 10-year window between 1969 and 2017, producing 39 separate percentage change values.
2. Calculate the mean and standard deviation of the percentage changes across these 39 observations.
3. From the peak demand model, obtain the estimated coefficient and standard error associated with the included economic variable.
4. The mean expected growth rate of demand is estimated as the product of the estimated coefficient and the mean of the 39 percentage change observations.
5. The standard deviation of the growth rate of demand is estimated by combining the standard error of the estimated coefficient with the standard deviation of the historical percentage changes in the economic variable.[5]
6. The coefficient of variation (CV) of the economic-based variability is calculated as the standard deviation calculated in step 5 divided by the mean expected growth rate calculated in step 4.
7. For any given forecast value, the high and low scenarios are simulated as the 90th and 10th percentile values (respectively) from a normal distribution, with a mean equal to

[5] This calculation is performed as the standard deviation of the product of two random variables, as follows: $Var(XY) = Var(X)Var(Y)+Var(X)(E(Y))^2+Var(Y)(E(X))^2$

the “base” forecast growth rate and the standard deviation equal to the absolute value of the base forecast growth rate[6] multiplied by the CV calculated in Step 6.

8. These high and low percentages are applied to the demand and sales forecasts in each of the forecast months.

3. THE BLACK HILLS POWER (SOUTH DAKOTA) FORECAST

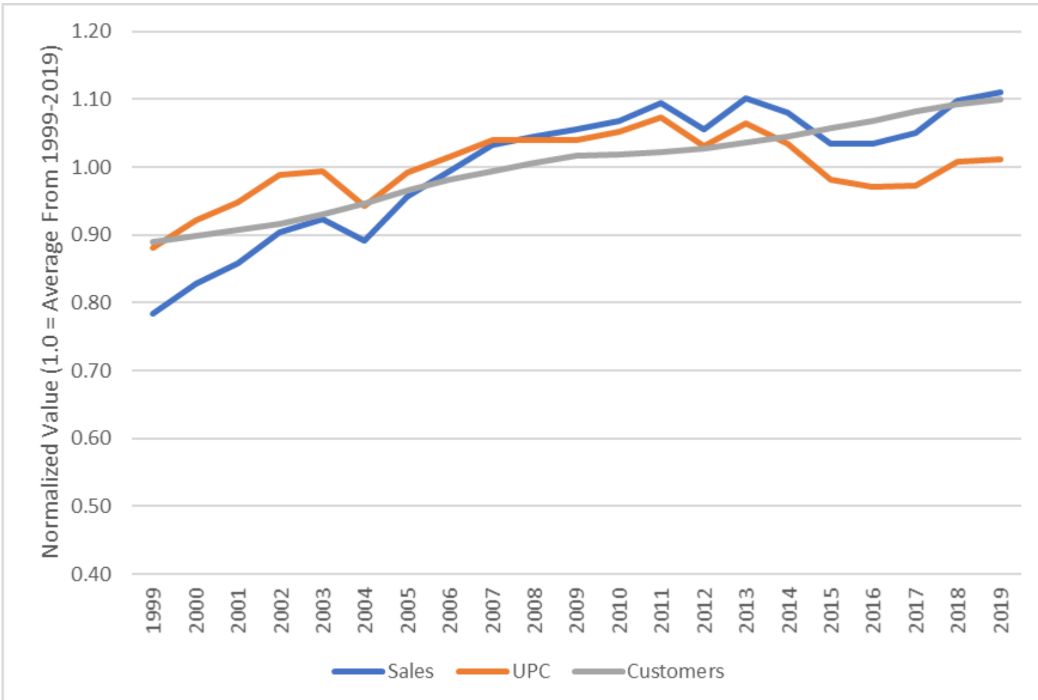
In this section, we describe the forecasting models for each customer class in the Black Hills Power (BHP) service territory. In each case, we show a graph reflecting historical annual sales, use per customer (UPC), and the number of customers over time. Each series is normalized to show a value that is indexed to the average across the time period shown (i.e., a value of 0.9 means that year’s value is 90 percent of the average over the time period shown). This normalization facilitates a comparison of trends in the outcomes across years, which naturally occur on different scales. The figures show observed (non-weather normalized) values. The Appendix contains detailed results for each forecast model.

3.1 Residential

Figure 3.1 shows the normalized sales, UPC, and customer counts for BHP’s Residential customer class. The upward trend in sales appears to be primarily driven by growth in customers served, while year-to-year variations in total sales are highly correlated with those of UPC. We estimate separate UPC and customer models to better account for these separate effects.

[6] Taking the absolute value of the forecast growth rate is necessary because standard deviations cannot be negative.

Figure 3.1: BHP Residential Normalized Sales, UPC, and Customer Counts



The Residential UPC model is:

$$\ln(upc_t) = a + b^{CDD} \text{ x } CDD_t + b^{HDD} \text{ x } HDD_t + b^{Trend} \text{ x } Trend_t + \Sigma_m(b^m \text{ x } Month_{m,t}) + e_t$$

In this equation, *a* and the *b*'s are estimated parameters; e_t is the error term; *t* indexes time periods; and *m* indexes months. The explanatory variables are:

- CDD_t = CDD using a 60°F threshold
- HDD_t = HDD using a 60°F threshold
- $Trend_t$ = Time trend
- $Month_{m,t}$ = month dummies[7]

The model is estimated using data from 2007 through 2019 using the Prais-Winsten serial correlation correction. No available economic or demographic variables produced a reasonable coefficient estimate. Data prior to 2007 is excluded due to the high growth in UPC during that period vs. more recent years. The time trend accounts for the slight downward trend in UPC following 2007 (approximately 0.5 percent per year).

[7] The model includes eleven month-specific dummies, with the January variable omitted to prevent perfect multicollinearity of the month variables. That is, the coefficients for the included months are interpreted as an effect relative to the omitted month.

The Residential customer model is:

$$\ln(custs_t) = a + b^{Emp} \times \ln(TotEmp_t) + \Sigma_m(b^m \times Month_{m,t}) + e_t$$

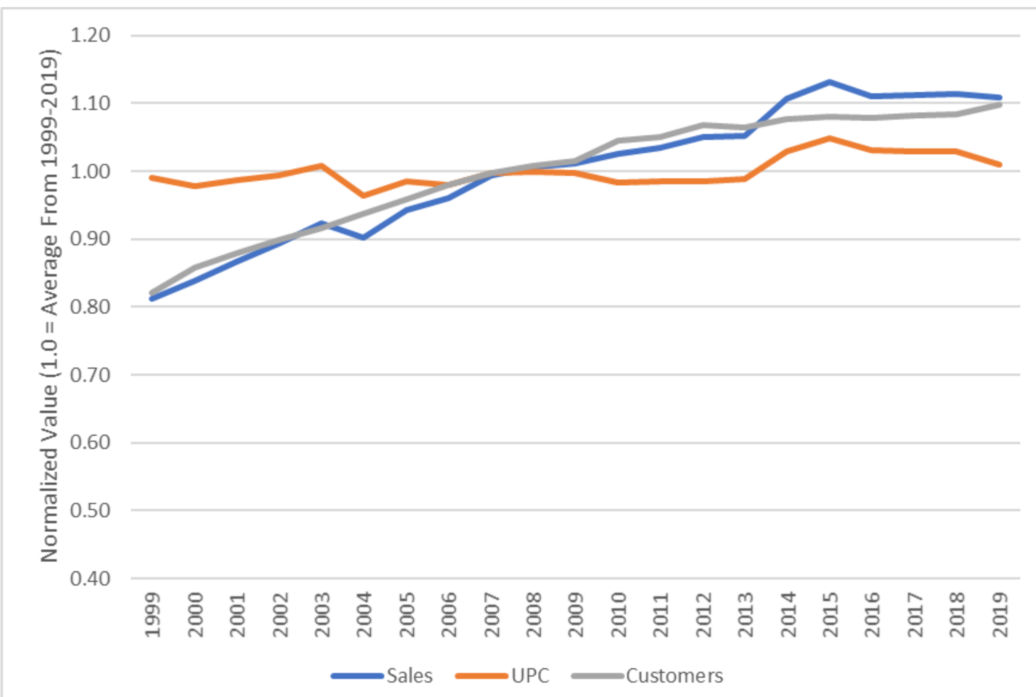
The explanatory variables are:
- $\ln(TotEmp_t)$ = the natural log of total employment (12-month moving average)
- $Month_{m,t}$ = month dummies

The model is estimated using data from 2007 through 2019 using the Prais-Winsten serial correlation correction. The estimated coefficient on the total employment variable reflects a positive relationship between economic conditions and the number of customers served.

3.2 Commercial

As Figure 3.2 shows, BHP's Commercial UPC (and as a result, total sales) increased to a higher level beginning around 2014. This upward shift appears to be due to customers changing classes, resulting in an influx of customers that led to a one-time shift in UPC. Class sales, which had been increasing prior to 2014, were largely flat following the class shift.

Figure 3.2: BHP Commercial Normalized Sales, UPC, and Customer Counts



The Commercial UPC model is:

$$\ln(upc_t) = a + b^{CDD} \times CDD_t + b^{HDD} \times HDD_t + b^{Shift} \times ClassShift_t + b^{Trend} \times Trend_t + b^{Emp} \times \ln(TotEmp_t) + \Sigma_m(b^m \times Month_{m,t}) + e_t$$

The explanatory variables are:

- CDD_t = CDD using a 60°F threshold
- HDD_t = HDD using a 60°F threshold
- $ClassShift_t$ = a "class shift" indicator variable equal to 1 beginning in June 2014 and 0 prior to that month
- $Trend_t$ = Time trend
- $\ln(TotEmp_t)$ = the natural log of total employment (12-month moving average)
- $Month_{m,t}$ = month dummies

The model is estimated using data from 1999 through 2019 using the Prais-Winsten serial correlation correction. The estimated coefficients for the employment and time trend variables reflect offsetting effects. Commercial UPC increases with employment, with a separate downward trend of approximately 0.6 percent per year. The estimated coefficient for the class shift variable indicates 6.1 percent higher UPC during the post-June 2014 period.

The Commercial customer model is:

$$\ln(custs_t) = a + b^{Emp} \times \ln(TotEmp_t) + b^{Emp\_Shift} \times (TotEmp_t \times ClassShift_t) + b^{Shift} \times ClassShift_t + \Sigma_m(b^m \times Month_{m,t}) + e_t$$

The explanatory variables are:

- $\ln(TotEmp_t)$ = The natural log of total employment (12-month moving average)
- $ClassShift_t$ = A "class shift" indicator variable equal to 1 beginning in June 2014 and 0 prior to that month
- An interaction between the ln(total employment) variable and the class shift variable
- $Month_{m,t}$ = month dummies

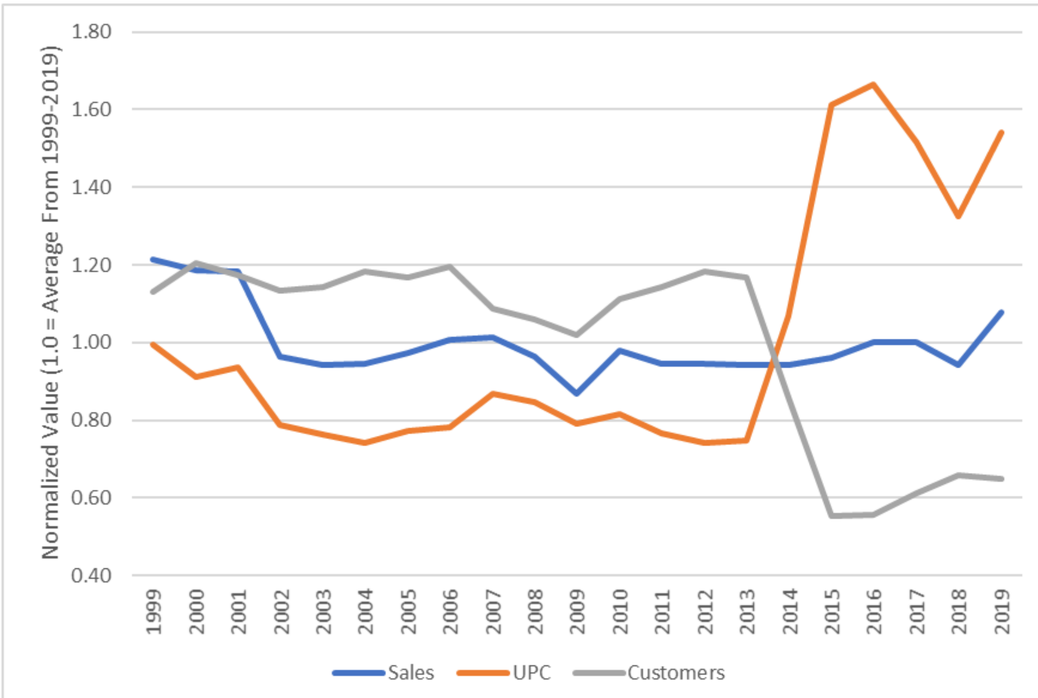
The model is estimated using data from 1999 through 2019 using the Prais-Winsten serial correlation correction. The interaction between the class shift variable and the total employment variable allows the effect of employment to differ before and after the class shift occurs. The estimates reflect a much higher employment effect in the pre-shift period.

The forecast produced by this model had a reasonable annual growth rate but some prediction error in the final year that resulted in a forecast that started from a level that appeared to be too high. To remedy this, we applied the forecast percentage growth rate to the last year's weather normalized sales. The weather normalization adjustment was developed as the difference between the model's predicted sales at normal and observed weather. That difference was added to observed sales to arrive at weather-normalized sales.

3.3 Industrial

This class is not forecast using a statistical model, with flat sales (i.e., no growth) assumed during the forecast period. Figure 3.3 shows the reasonableness of this assumption. The class shift described above for the Commercial class affected this class as well, resulting in a reduction in the number of customers and an increase in UPC. Note that the effect of the shift is more pronounced for this class, as it has fewer customers than the Commercial class (25 to 40 Industrial customers vs. more than 12,000 Commercial customers). Because the shifted customers represented a relatively low share of class sales, the class sales remained relatively flat through the 2014 class-shift period.

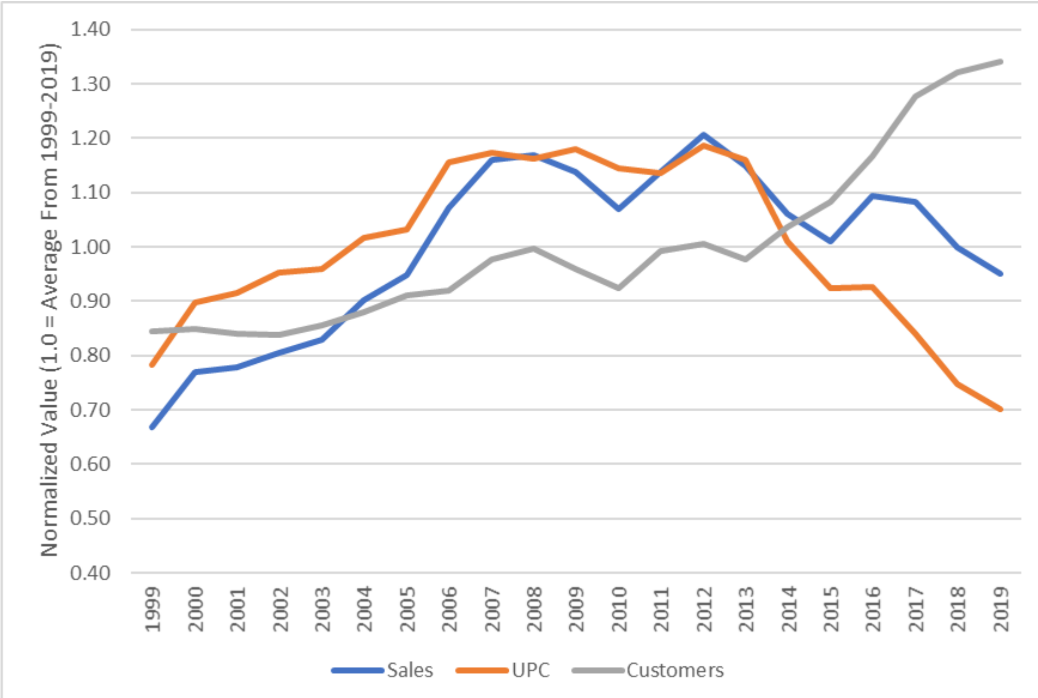
Figure 3.3: BHP Industrial Normalized Sales, UPC, and Customer Counts



3.4 Municipal

Sales to BHP's Municipal class have displayed varying dynamics from 1999 to 2019, with rapid increases through 2007 followed by a plateau and an eventual decline. No economic or demographic variables explain these changes over time. As a result, our forecasting model focuses on following the observed trends and basing the forecast on the post-2007 experience. Note that the Municipal class accounts for a small percentage of BHP's total sales (1.1% in 2019).

Figure 3.4: BHP Municipal Normalized Sales, UPC, and Customer Counts



The Municipal sales model is:

$$\ln(upc_t) = a + b^{CDD} \times CDD_t + b^{D2007} \times D2007_t + b^{Trend} \times Trend_t + b^{Trend07} \times (Trend_t \times D2007_t)$$
$$+ \Sigma_m(b^m \times Month_{m,t}) + e_t$$

The explanatory variables are:

- CDD_t = CDD using a 60°F threshold
- $D2007_t$ = a2007 indicator variable equal to 1 beginning in January 2007 and 0 prior to that month
- $Trend_t$ = Time trend
- An interaction between the 2007 indicator variable and the time trend
- $Month_{m,t}$ = month dummies

The model is estimated using data from 1999 through 2019 using the Prais-Winsten serial correlation correction. The estimated time trends show approximately 5.3 percent per year growth through 2006, with a -1.3 percent per year change in sales from 2007 on.

3.5 System Peak Demand

Forecasting system peak demand presents different challenges than forecasting monthly sales. The objective of the statistical model is to explain the factors that contribute to the most extreme observed loads. To increase the sample size of "peak-like" hours, we include all hours that are within 1 percent of each month's peak demand value.

The system demand model is:

$$\ln(MW_t) = a + b^{CDD} \times CDD_t + b^{HDD} \times HDD_t + b^{CDD\_d} \times CDD\_Day_t + b^{HDD\_d} \times HDD\_Day_t$$
$$+ b^{Wknd} \times Weekend_t + b^{PI} \times \ln(TotPI_t) + \Sigma_m(b^m \times Month_{m,t}) + e_t$$

The explanatory variables are:

- CDD_t = the date's CDD using a 60°F threshold
- HDD_t = the date's HDD using a 60°F threshold
- CDD_Day_t = average CDD per day during the month
- HDD_Day_t = average HDD per day during the month
- $\ln(TotPI_t)$ = the natural log of total personal income
- $Weekend_t$ = a weekend indicator variable (equal to 1 on weekends and zero on weekdays)
- $Month_{m,t}$ = month dummies

The date specific CDD and HDD variables account for the effect of the day's temperatures on the peak day's loads. The monthly average CDD and HDD variables reflect the overall weather conditions (e.g., heat or cold buildup) surrounding the peak day. The personal income variable reflects the effect of economic conditions on peak demand. The weekend indicator variable allows the model to explain the fact that weekend peaks are lower than weekday peaks, all else equal (by approximately 2.3 percent, according to our estimate). The month dummies reflect seasonal patterns in peak demand.

The model is estimated using data from 2010 through 2019. No correction is made for serial correlation.[8]

4. THE CHEYENNE LIGHT FUEL AND POWER (WYOMING) FORECAST

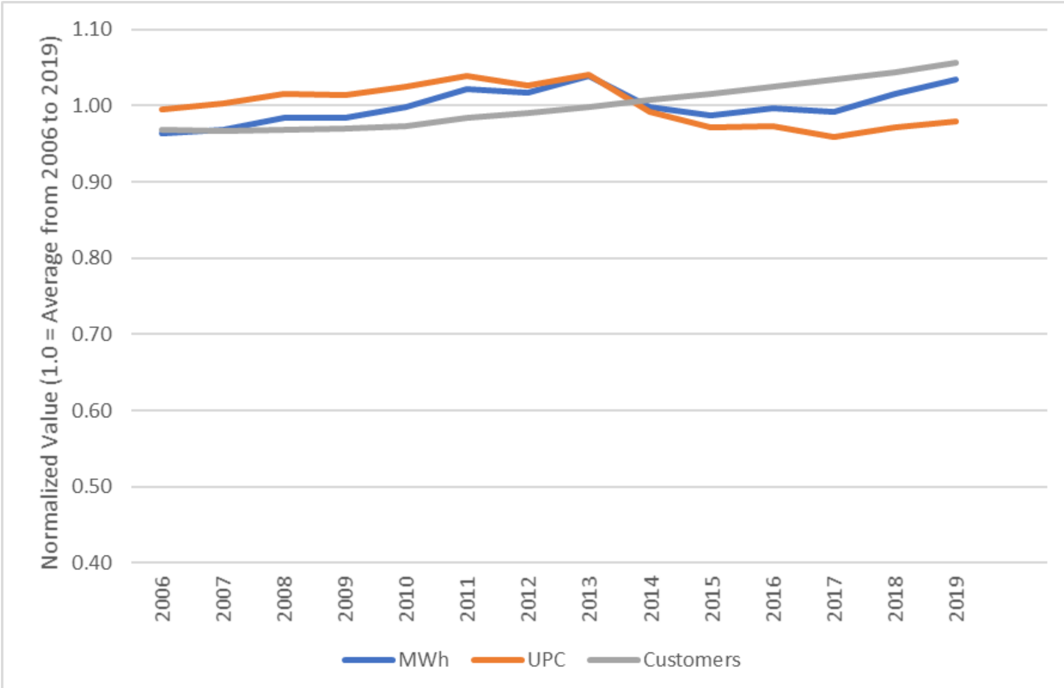
This section contains a description of each CLFP forecast model. The Appendix provides detailed results for each model.

4.1 Residential

Figure 4.1 shows the normalized sales, UPC, and customer counts for CLFP's Residential customer class. The overall upward trend in sales appears to be primarily driven by growth in customers served, while year-to-year variations in total sales are highly correlated with those of UPC. UPC (and therefore sales) drops in the years following 2013 but recovers somewhat in the most recent years. We estimate separate UPC and customer models to better account for these separate effects.

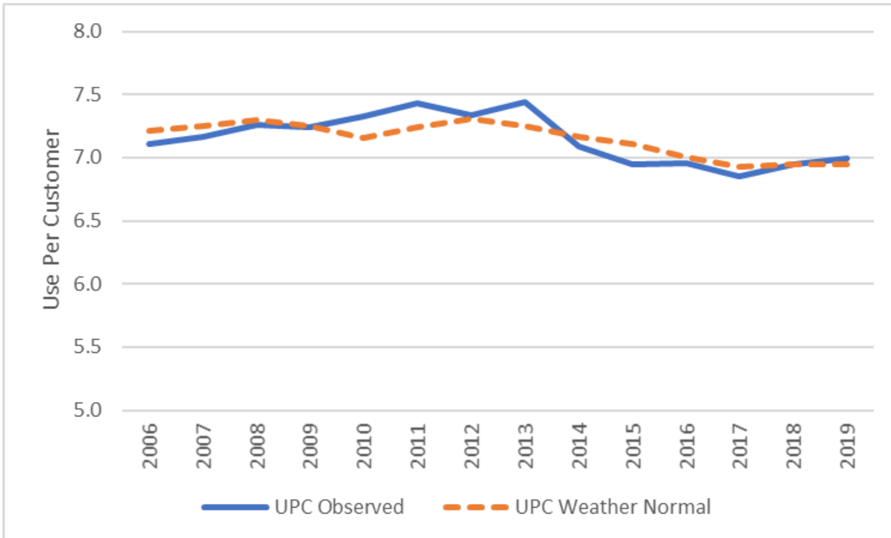
[8] Unlike the monthly class sales models, the interval between observations can vary in the peak demand model. This makes it difficult to identify and correct for serial correlation.

Figure 4.1: CLFP Residential Normalized Sales, UPC, and Customer Counts



We examined weather normalized UPC to test whether the dip in UPC that occurs from 2014 through 2017 was due to mild weather. In Figure 4.2 below, the blue line represents observed UPC while the dashed orange line reflects weather normalized UPC. We conclude from this that some of the reduction in UPC was due to weather, but the decline was still somewhat steady through those years.

Figure 4.2: BHP Residential Observed vs. Weather Normalized UPC



The Residential UPC model is:

$$\ln(upc_t) = a + b^{CDD} \text{ x } CDD_t + b^{HDD} \text{ x } HDD_t + b^{Inc} \text{ x } \ln(HhldInc_t) + b^{Trend} \text{ x } Trend_t$$
$$+ \Sigma_m(b^m \text{ x } Month_{m,t}) + e_t$$

The explanatory variables are:

- CDD_t = CDD using a 60°F threshold
- HDD_t = HDD using a 60°F threshold
- $\ln(HhldInc_t)$ = the natural log of real household total personal income (12-month moving average)
- $Trend_t$ = Time trend
- $Month_{m,t}$ = month dummies

The model is estimated using data from February 2005 through December 2019 using the Prais-Winsten serial correlation correction. The estimated time trend reflects a 0.7 percent per year decline in UPC, which is offset to some extent by the positive relationship between household income and UPC.

The Residential customer model is:

$$\ln(custs_t) = a + b^{Hhld\_pre} \text{ x } \{\ln(Hhlds_t) \text{ x } Pre2010_t\} + b^{Hhld\_CIS} \text{ x } \{\ln(Hhlds_t) \text{ x } CISplus_t\} + b^{CIS} \text{ x } CISplus_t$$
$$+ \Sigma_m(b^m \text{ x } Month_{m,t}) + e_t$$

The explanatory variables are:

- $\ln(Hhlds_t)$ x $Pre2010_t$ = the natural log of the number of households interacted with a pre-2010 indicator variable

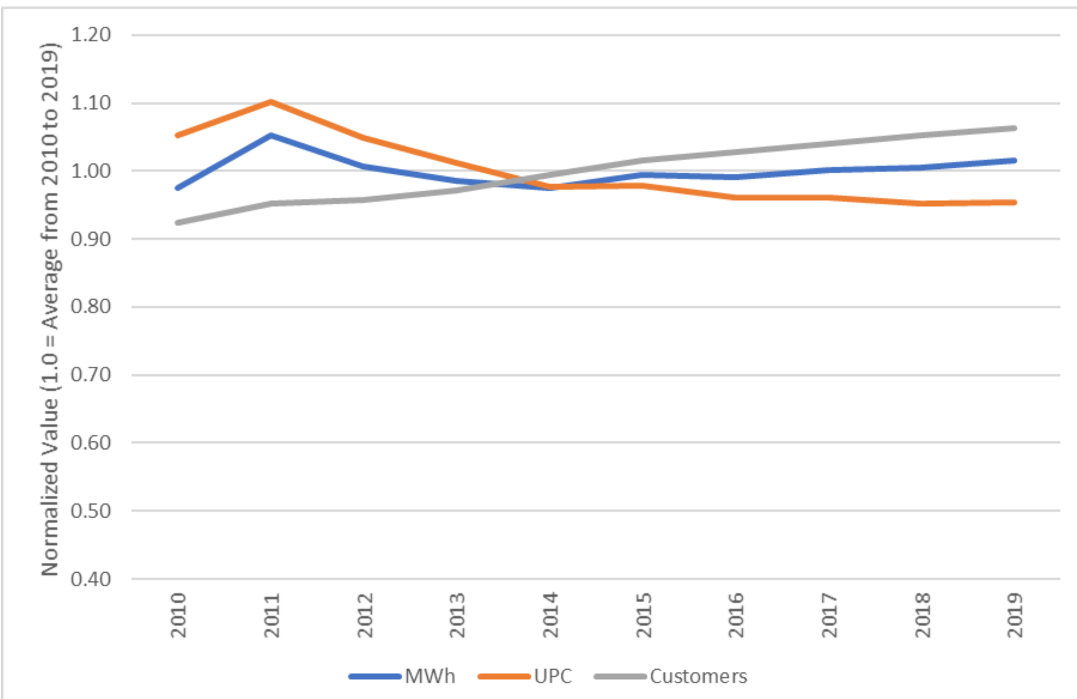
- ln($Hhlds_t$) x $CISplus_t$ = the natural log of the number of households interacted with a 2010+ indicator variable
- $CISplus_t$ = a 2010+ indicator variable, reflecting the approximate date that CLFP's new CIS system was implemented (and thus may have affected the recording of customer counts)

The model is estimated using data from February 2005 through December 2019 using the Prais-Winsten serial correlation correction. The number of households is positively related to the number of customers in the 2010+ period, with no statistically significant relationship estimated in the preceding years.

4.2 Commercial Non-Demand

Figure 4.3 shows large changes in sales and UPC for CLFP's Commercial Non-Demand customers during the 2010 to 2013 period, followed by a more stable period through 2019. In contrast, the number of customers increases steadily through the 2010 to 2019 period.

Figure 4.3: CLFP Commercial Non-Demand Normalized Sales, UPC, and Customer Counts



The Commercial Non-Demand UPC model is:

$$\ln(upc_t) = a + b^{CDD} \text{ x } CDD_t + b^{HDD} \text{ x } HDD_t + b^{Trend} \text{ x } Trend_t + \Sigma_m(b^m \text{ x } Month_{m,t}) + e_t$$

The explanatory variables are:

- CDD_t = CDD using a 60°F threshold
- HDD_t = HDD using a 60°F threshold
- $Trend_t$ = Time trend
- $Month_{m,t}$ = month dummies

The model is estimated using data from 2014 through 2019 using the Prais-Winsten serial correlation correction. No available economic or demographic variables produced a reasonable estimate. Data prior to 2014 is excluded due to the unexplained variability in UPC relative to more recent years. The time trend accounts for the slight downward trend in UPC from 2014 through 2019, at approximately 0.7 percent per year.

In the Commercial Non-Demand customer model, the sole explanatory variable is the natural log of total employment (12-month moving average).

$$\ln(custs_t) = a + b^{Emp} \times \ln(TotEmp_t) + e_t$$

We tested monthly indicator variables but found that they were not jointly statistically significant. The estimate on the employment variable indicates a positive relationship between economic conditions and the number of customers served.

4.3 Commercial General Service Secondary and Primary

Because of inter-class customer migrations during recent years, the forecast combines CLFP's General Service Secondary and Primary customers into a single forecast. Figures 4.4 and 4.5 show the changes in sales, UPC, and customer counts for each group. Notice how since 2013 sales have been persistently decreasing in the Secondary class and increasing in the Primary class. Customers re-classifying from Secondary to Primary are at least partially responsible for these trends. Figure 4.6 shows the corresponding values for the two classes combined, revealing a flatter sales trend since 2013.

Figure 4.4: CLFP GS Secondary Normalized Sales, UPC, and Customer Counts

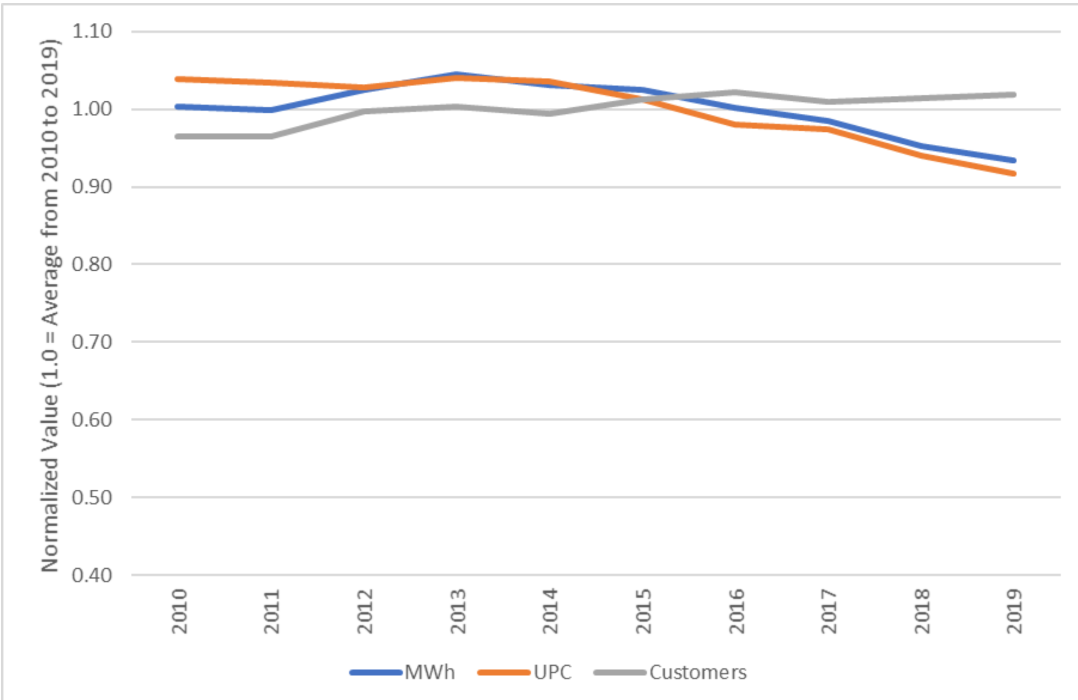


Figure 4.5: CLFP GS Primary Normalized Sales, UPC, and Customer Counts

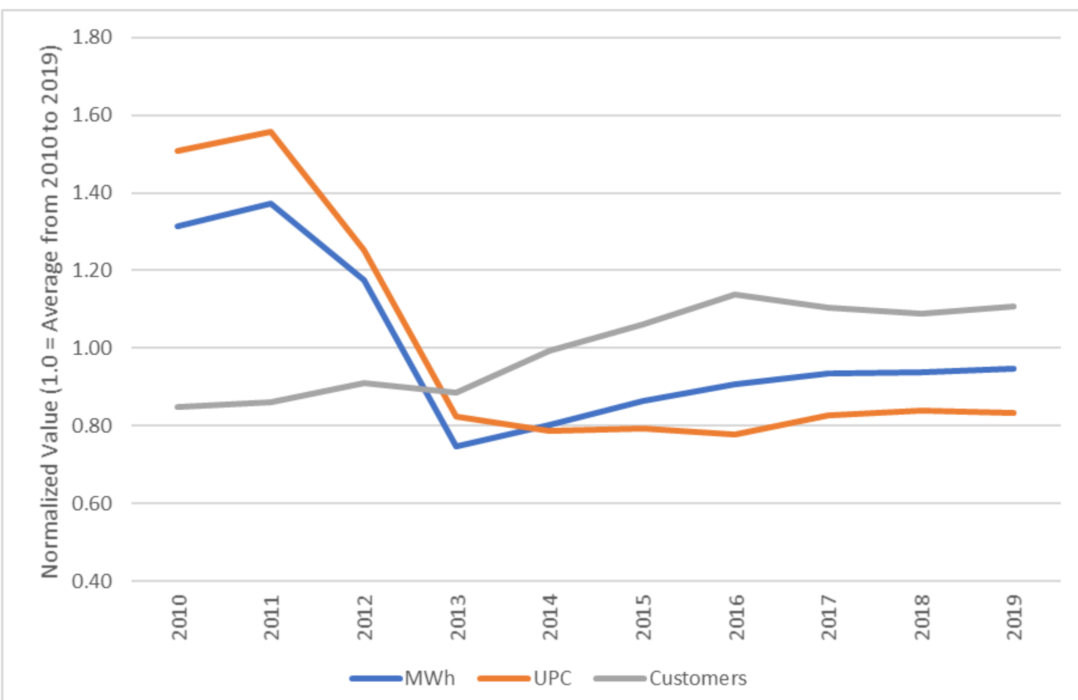
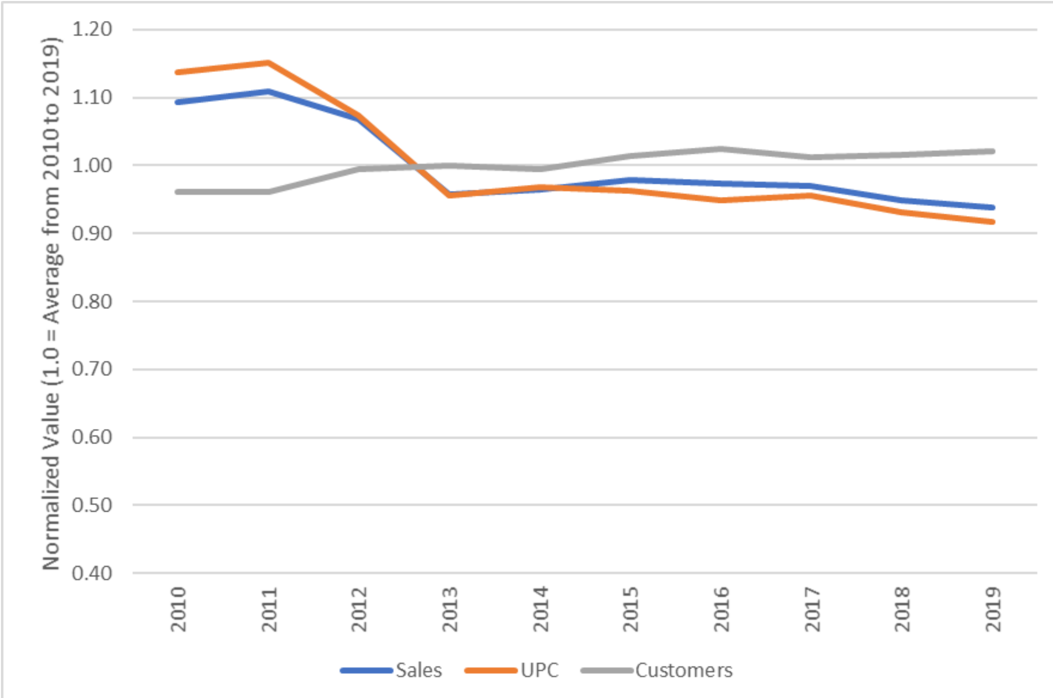


Figure 4.6: CLFP GS Secondary + Primary Normalized Sales, UPC, and Customer Counts

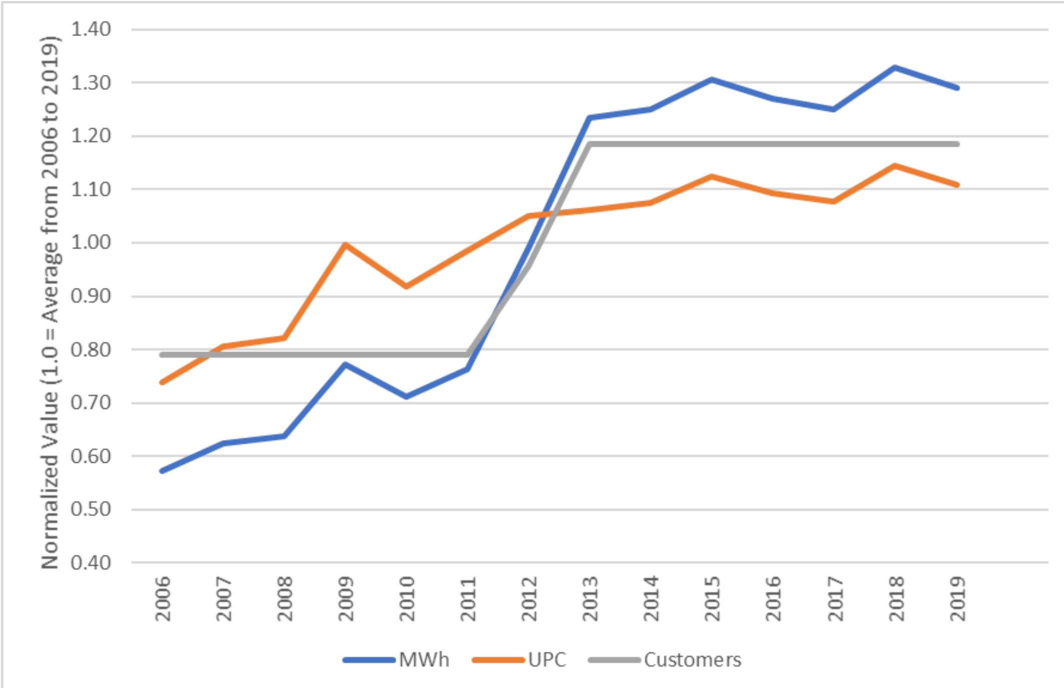


Statistical forecasting models developed for the combined General Service class produced declining sales, particularly in the 2030s and beyond. This contradicts Black Hills's expectations for this class, which is that sales will remain flat during the forecast period. Therefore, for this class Black Hills uses a forecast assumption of flat sales rather than a statistically based forecast.

4.4 Industrial

This class is not forecast using a statistical model, which is appropriate given that it only has two or three customers. With so few customers, variations in sales are likely more due to idiosyncratic effects on individual companies rather than reflections of widespread trends, making them difficult to explain using the data at hand. As Figure 4.7 shows, Industrial sales increase when a customer is added but have remained relatively constant in recent years.

Figure 4.7: CLFP Industrial Normalized Sales, UPC, and Customer Counts



4.5 System Peak Demand

As was the case for the BHP system peak demand model, the CLFP model includes all hours that are within 1 percent of each month's peak demand value.

The system demand model is:

$$\ln(MW_t) = a + b^{CDD} \times CDD_t + b^{HDD} \times HDD_t + b^{CDD\_d} \times CDD\_Day_t + b^{CDH} \times CDH_t + b^{HDH} \times HDH_t + b^{Emp} \times \ln(TotEmp_t) + \Sigma_m(b^m \times Month_{m,t}) + e_t$$

The explanatory variables are:

- CDD_t = the date's CDD using a 60°F threshold
- HDD_t = the date's HDD using a 60°F threshold
- CDD_Day_t = average CDD per day during the month
- CDH_t = Cooling degree hours (CDHs) during the peak hour[9]
- HDH_t = Heating degree hours (HDHs) during the peak hour[10]
- $\ln(TotEmp_t)$ = The natural log of total employment
- $Month_{m,t}$ = month dummies

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[9] CDH_h = MAX{0, $Temp_h$ – 70}, where h is the hour in question.

[10] HDH_h = MAX{0, 50 – $Temp_h$}, where h is the hour in question.

The date specific CDD and HDD variables account for the effect of the day's temperatures on the peak day's loads. The CDH and HDH variables reflect temperatures in the peak hour itself. The monthly average CDD variable reflects the overall weather conditions (e.g., heat buildup) surrounding the peak day. The total employment variable reflects the effect of economic conditions on peak demand. The month dummies reflect seasonal patterns in peak demand.

The model is estimated using data from 2008 through 2019. As with the BHP peak demand model, no correction is made for serial correlation.

APPENDIX: ESTIMATED MODELS

BHP Residential UPC Model

```
Prais-Winsten AR(1) regression -- iterated estimates

      Source |       SS           df       MS      Number of obs   =       156
-------------+----------------------------------   F(14, 141)      =    279.48
       Model |  6.59638489        14   .47117035   Prob > F        =    0.0000
    Residual |   .23771102       141  .001685894   R-squared       =    0.9652
-------------+----------------------------------   Adj R-squared   =    0.9618
       Total |  6.83409591       155  .044090941   Root MSE        =    .04106

------------------------------------------------------------------------------
        lupc |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
       cdd60 |   .0007491   .0000792     9.46   0.000     .0005925    .0009057
       hdd60 |   .0003371   .0000268    12.56   0.000      .000284    .0003901
       trend |  -.0053457   .0011228    -4.76   0.000    -.0075653   -.003126
          m2 |  -.0809981   .0146294    -5.54   0.000    -.1099194   -.0520769
          m3 |  -.0765306   .0176738    -4.33   0.000    -.1114705   -.0415906
          m4 |  -.1715452   .0214173    -8.01   0.000    -.2138857   -.1292046
          m5 |  -.2487149   .0261492    -9.51   0.000    -.3004101   -.1970197
          m6 |  -.2838251   .0317412    -8.94   0.000    -.3465753    -.221075
          m7 |   -.220695   .0402097    -5.49   0.000    -.3001869   -.1412031
          m8 |  -.1982313   .0444751    -4.46   0.000    -.2861556   -.1103071
          m9 |  -.2625503   .0377637    -6.95   0.000    -.3372066    -.187894
         m10 |  -.3046907   .0290236   -10.50   0.000    -.3620684   -.2473129
         m11 |  -.2245492   .0227044    -9.89   0.000    -.2694342   -.1796643
         m12 |  -.0621735   .0159359    -3.90   0.000    -.0936777   -.0306693
       _cons |   6.704262   .0353275   189.77   0.000     6.634422    6.774102
-------------+----------------------------------------------------------------
         rho |   .2203338
------------------------------------------------------------------------------
Durbin-Watson statistic (original)    1.688659
Durbin-Watson statistic (transformed) 2.075256
```

BHP Residential Customer Model

```
Prais-Winsten AR(1) regression -- iterated estimates

      Source |       SS           df       MS      Number of obs   =       156
-------------+----------------------------------   F(12, 143)      >  99999.00
       Model |  11.7509368        12  .979244731   Prob > F        =    0.0000
    Residual |  .000585916       143  4.0973e-06   R-squared       =    1.0000
-------------+----------------------------------   Adj R-squared   =    0.9999
       Total |  11.7515227       155  .075816275   Root MSE        =    .00202

------------------------------------------------------------------------------
       lcust |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
  lntotemp12 |   .8832825   .0454891    19.42   0.000     .7933645    .9732005
          m2 |  -.0001767   .0005589    -0.32   0.752    -.0012813     .000928
          m3 |   .0006558   .0007511     0.87   0.384    -.0008289    .0021405
          m4 |   .0001208   .0008707     0.14   0.890    -.0016003    .0018418
          m5 |   .0001964   .0009466     0.21   0.836    -.0016746    .0020675
          m6 |   .0004601   .0009896     0.46   0.643    -.0014959    .0024161
          m7 |  -.0002992   .0010043    -0.30   0.766    -.0022843    .0016859
          m8 |    .001199   .0009921     1.21   0.229    -.0007621      .00316
          m9 |   .0015761   .0009518     1.66   0.100    -.0003053    .0034574
         m10 |   .0011851    .000879     1.35   0.180    -.0005525    .0029226
         m11 |   .0006704   .0007636     0.88   0.381     -.000839    .0021799
         m12 |   .0014634    .000579     2.53   0.013     .0003189    .0026079
       _cons |   7.853703    .158067    49.69   0.000     7.541253    8.166152
-------------+----------------------------------------------------------------
         rho |   .9162612
------------------------------------------------------------------------------
Durbin-Watson statistic (original)    0.198497
Durbin-Watson statistic (transformed) 2.673149
```

BHP Commercial UPC Model

```
Prais-Winsten AR(1) regression -- iterated estimates

      Source |       SS           df       MS      Number of obs   =       252
-------------+----------------------------------   F(16, 235)      =    152.52
       Model |   3.2015146        16  .200094662   Prob > F        =    0.0000
    Residual |  .308297984       235  .001311906   R-squared       =    0.9122
-------------+----------------------------------   Adj R-squared   =    0.9062
       Total |  3.50981258       251  .013983317   Root MSE        =    .03622

------------------------------------------------------------------------------
        lupc |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
       cdd60 |   .0004078   .0000516     7.90   0.000     .0003062    .0005095
       hdd60 |   .0000878   .0000188     4.68   0.000     .0000508    .0001248
          m2 |  -.0520282    .011984    -4.34   0.000     -.075638   -.0284183
          m3 |  -.0386922   .0118223    -3.27   0.001    -.0619834    -.015401
          m4 |  -.0847384   .0139929    -6.06   0.000    -.1123059   -.0571708
          m5 |  -.0978604   .0170247    -5.75   0.000    -.1314009   -.0643199
          m6 |  -.0237413   .0208928    -1.14   0.257    -.0649023    .0174197
          m7 |   .0054528   .0265259     0.21   0.837    -.0468061    .0577117
          m8 |   .0245937   .0296813     0.83   0.408    -.0338816    .0830691
          m9 |  -.0073286   .0249257    -0.29   0.769     -.056435    .0417778
         m10 |  -.0483032   .0188734    -2.56   0.011    -.0854859   -.0111205
         m11 |  -.0999738   .0147761    -6.77   0.000    -.1290844   -.0708633
         m12 |  -.0056054   .0123565    -0.45   0.651     -.029949    .0187383
 class_shift |   .0605904   .0081693     7.42   0.000      .044496    .0766848
       trend |  -.0061663   .0028089    -2.20   0.029       -.0117   -.0006325
  lntotemp12 |   .4757653    .236463     2.01   0.045     .0099071    .9416235
       _cons |   6.844035   .7777653     8.80   0.000     5.311752    8.376318
-------------+----------------------------------------------------------------
         rho |  -.1303725
------------------------------------------------------------------------------
Durbin-Watson statistic (original)    2.237867
Durbin-Watson statistic (transformed) 1.976362
```

BHP Commercial Customer Model

```
Prais-Winsten AR(1) regression -- iterated estimates

      Source |       SS           df       MS      Number of obs   =       252
-------------+----------------------------------   F(14, 237)      =  13152.44
       Model |  14.0120084        14  1.00085775   Prob > F        =    0.0000
    Residual |  .018034924       237  .000076097   R-squared       =    0.9987
-------------+----------------------------------   Adj R-squared   =    0.9986
       Total |  14.0300434       251  .055896587   Root MSE        =    .00872

--------------------------------------------------------------------------------
         lcust |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
---------------+----------------------------------------------------------------
            m2 |  -.0038088   .0020341    -1.87   0.062     -.007816    .0001983
            m3 |  -.0015248   .0026583    -0.57   0.567    -.0067617    .0037121
            m4 |   .0036183   .0030146     1.20   0.231    -.0023205    .0095571
            m5 |   .0125077    .003226     3.88   0.000     .0061525    .0188629
            m6 |   .0186227    .003345     5.57   0.000      .012033    .0252123
            m7 |   .0214386   .0033801     6.34   0.000     .0147797    .0280976
            m8 |   .0277128   .0033456     8.28   0.000     .0211218    .0343038
            m9 |   .0211541   .0032357     6.54   0.000     .0147796    .0275286
           m10 |   .0148503   .0030301     4.90   0.000      .008881    .0208197
           m11 |   .0087593   .0026822     3.27   0.001     .0034752    .0140433
           m12 |    .000228   .0020735     0.11   0.913     -.003857    .0043129
    lntotemp12 |   1.490022   .0418228    35.63   0.000     1.407631    1.572414
lntotemp_shift |  -1.292099   .2045018    -6.32   0.000    -1.694973   -.8892259
   class_shift |   4.491643   .7154039     6.28   0.000      3.08228    5.901006
         _cons |   4.291352   .1422813    30.16   0.000     4.011054     4.57165
---------------+----------------------------------------------------------------
           rho |   .7318557
--------------------------------------------------------------------------------
Durbin-Watson statistic (original)    0.548459
Durbin-Watson statistic (transformed) 2.435974
```

BHP Municipal Sales Model

Prais-Winsten AR(1) regression -- iterated estimates

Source	SS	df	MS			
				Number of obs	=	252
				F(15, 236)	=	82.04
Model	13.5463717	15	.903091449	Prob > F	=	0.0000
Residual	2.5978093	236	.011007667	R-squared	=	0.8391
				Adj R-squared	=	0.8289
Total	16.144181	251	.064319446	Root MSE	=	.10492

lsales	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
cdd60	.0010164	.0001617	6.29	0.000	.0006978	.001335
trend	.0533716	.0061685	8.65	0.000	.0412193	.0655239
trend_d2007	-.0661732	.0068731	-9.63	0.000	-.0797138	-.0526326
d2007	.7528875	.0587961	12.81	0.000	.6370553	.8687198
m2	-.1061182	.0289156	-3.67	0.000	-.1630839	-.0491526
m3	-.0802588	.032359	-2.48	0.014	-.1440082	-.0165094
m4	-.0846191	.0331771	-2.55	0.011	-.1499801	-.019258
m5	-.0232965	.0334686	-0.70	0.487	-.0892319	.0426389
m6	.1198732	.037011	3.24	0.001	.0469591	.1927873
m7	.1241075	.0616468	2.01	0.045	.0026591	.2455559
m8	.0635651	.0754108	0.84	0.400	-.0849993	.2121295
m9	.088161	.0548742	1.61	0.109	-.0199449	.1962669
m10	.0585193	.0343227	1.70	0.090	-.0090986	.1261372
m11	-.1457969	.0324917	-4.49	0.000	-.2098077	-.0817861
m12	-.0417205	.0292042	-1.43	0.154	-.0992546	.0158136
_cons	6.874499	.0398607	172.46	0.000	6.795971	6.953028
rho	.2525515					

Durbin-Watson statistic (original)   1.509298

Durbin-Watson statistic (transformed) 2.016210

BHP System Peak Demand Model

Source	SS	df	MS			
				Number of obs	=	230
				F(17, 212)	=	137.46
Model	3.03781492	17	.178694996	Prob > F	=	0.0000
Residual	.275587388	212	.001299941	R-squared	=	0.9168
				Adj R-squared	=	0.9102
Total	3.31340231	229	.014469006	Root MSE	=	.03605

lmwnat	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
cdd60	.0086782	.0009586	9.05	0.000	.0067885	.0105678
hdd60	.0027718	.0004093	6.77	0.000	.001965	.0035785
mnthcdd60perday	.01034	.0020343	5.08	0.000	.0063298	.0143501
mnthhdd60perday	.0042651	.0008499	5.02	0.000	.0025897	.0059405
lntotPI	.3380472	.0384863	8.78	0.000	.2621824	.4139121
weekend	-.0233456	.0114565	-2.04	0.043	-.0459288	-.0007625
m2	-.0523044	.0116995	-4.47	0.000	-.0753668	-.0292421
m3	-.0416192	.0138153	-3.01	0.003	-.0688522	-.0143861
m4	-.080603	.0160687	-5.02	0.000	-.1122778	-.0489281
m5	-.0320146	.0203971	-1.57	0.118	-.0722217	.0081925
m6	.0932003	.0273189	3.41	0.001	.0393488	.1470519
m7	.0802717	.03224	2.49	0.014	.0167197	.1438237
m8	.0892537	.0299565	2.98	0.003	.0302028	.1483045
m9	.0623604	.025859	2.41	0.017	.0113867	.113334
m10	-.0339564	.0189731	-1.79	0.075	-.0713565	.0034436
m11	-.0216245	.0155354	-1.39	0.165	-.0522481	.008999
m12	-.027556	.011648	-2.37	0.019	-.0505167	-.0045953
_cons	2.867306	.2934284	9.77	0.000	2.288895	3.445717

CLFP Residential UPC Model

```
Prais-Winsten AR(1) regression -- iterated estimates

      Source |       SS           df       MS      Number of obs   =       179
-------------+----------------------------------   F(15, 163)      =    114.28
       Model |  2.06797158        15  .137864772   Prob > F        =    0.0000
    Residual |  .196636554       163  .001206359   R-squared       =    0.9132
-------------+----------------------------------   Adj R-squared   =    0.9052
       Total |  2.26460814       178  .012722518   Root MSE        =    .03473

------------------------------------------------------------------------------
        lupc |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
       cdd60 |   .0006874   .0000816     8.42   0.000     .0005263    .0008485
       hdd60 |   .0002053   .0000278     7.39   0.000     .0001504    .0002602
  lnincome12 |   .4358274   .0999293     4.36   0.000     .2385045    .6331504
       trend |  -.0067252    .001048    -6.42   0.000    -.0087946   -.0046559
          m2 |  -.1014795   .0126135    -8.05   0.000    -.1263864   -.0765726
          m3 |  -.1002444    .014534    -6.90   0.000    -.1289436   -.0715453
          m4 |  -.1743273    .017176   -10.15   0.000    -.2082435   -.1404111
          m5 |  -.2145596   .0207049   -10.36   0.000     -.255444   -.1736752
          m6 |  -.2040182   .0272919    -7.48   0.000    -.2579095   -.1501269
          m7 |  -.1671883   .0341282    -4.90   0.000    -.2345787   -.0997979
          m8 |  -.1762289   .0372566    -4.73   0.000    -.2497967   -.1026611
          m9 |  -.2100186   .0318326    -6.60   0.000     -.272876   -.1471612
         m10 |  -.2242816   .0248828    -9.01   0.000    -.2734158   -.1751474
         m11 |   -.184847   .0182471   -10.13   0.000    -.2208783   -.1488158
         m12 |  -.0530595    .013202    -4.02   0.000    -.0791285   -.0269905
       _cons |  -5.518172   1.151543    -4.79   0.000    -7.792037   -3.244308
-------------+----------------------------------------------------------------
         rho |   .0804959
------------------------------------------------------------------------------
Durbin-Watson statistic (original)    1.873708
Durbin-Watson statistic (transformed) 2.014441
```

CLFP Residential Customer Model

```
Prais-Winsten AR(1) regression -- iterated estimates

      Source |       SS           df       MS      Number of obs   =       179
-------------+----------------------------------   F(3, 175)       >  99999.00
       Model |  17.7840565         3  5.92801885   Prob > F        =    0.0000
    Residual |  .000921729       175  5.2670e-06   R-squared       =    0.9999
-------------+----------------------------------   Adj R-squared   =    0.9999
       Total |  17.7849783       178  .099915608   Root MSE        =    .00229

-------------------------------------------------------------------------------
       lcusts |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
--------------+----------------------------------------------------------------
  lhhld_pre10 |  -.0812966   .0565073    -1.44   0.152      -.19282    .0302268
lhhld_CISplus |   .6734902   .0222876    30.22   0.000     .6295031    .7174773
      CISplus |  -2.733243    .239088   -11.43   0.000     -3.20511   -2.261376
        _cons |     10.761   .2030163    53.01   0.000     10.36033    11.16168
--------------+----------------------------------------------------------------
          rho |   .7863497
-------------------------------------------------------------------------------
Durbin-Watson statistic (original)    0.433740
Durbin-Watson statistic (transformed) 2.368500
```

CLFP Commercial Non-Demand UPC Model

```
Prais-Winsten AR(1) regression -- iterated estimates

      Source |       SS           df       MS      Number of obs   =        72
-------------+----------------------------------   F(14, 57)       =     26.09
       Model |  .382507485        14  .027321963   Prob > F        =    0.0000
    Residual |   .05968656        57  .001047133   R-squared       =    0.8650
-------------+----------------------------------   Adj R-squared   =    0.8319
       Total |  .442194045        71  .006228085   Root MSE        =    .03236

------------------------------------------------------------------------------
        lupc |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
       cdd60 |   .0004083   .0001487     2.75   0.008     .0001105    .0007061
       hdd60 |   .0001288   .0000395     3.26   0.002     .0000496    .0002079
       trend |  -.0073876   .0027641    -2.67   0.010    -.0129226   -.0018527
          m2 |  -.0487067   .0179134    -2.72   0.009    -.0845777   -.0128357
          m3 |  -.0659655   .0209113    -3.15   0.003    -.1078397   -.0240913
          m4 |  -.1196877   .0258481    -4.63   0.000    -.1714476   -.0679279
          m5 |  -.1510517   .0305823    -4.94   0.000    -.2122917   -.0898118
          m6 |  -.1560555   .0386278    -4.04   0.000    -.2334063   -.0787047
          m7 |  -.1050686   .0509712    -2.06   0.044    -.2071366   -.0030006
          m8 |  -.0874926   .0572705    -1.53   0.132    -.2021747    .0271895
          m9 |     -.1392   .0479274    -2.90   0.005     -.235173   -.0432271
         m10 |  -.1530321   .0363063    -4.22   0.000    -.2257342   -.0803299
         m11 |  -.1492752   .0271702    -5.49   0.000    -.2036827   -.0948678
         m12 |  -.0318684   .0196828    -1.62   0.111    -.0712825    .0075456
       _cons |   .0584828   .0505365     1.16   0.252    -.0427147    .1596803
-------------+----------------------------------------------------------------
         rho |    .184152
------------------------------------------------------------------------------
Durbin-Watson statistic (original)    1.680528
Durbin-Watson statistic (transformed) 1.996436
```

CLFP Commercial Non-Demand Customer Model

```
rais-Winsten AR(1) regression -- iterated estimates

      Source |       SS           df       MS      Number of obs   =        72
-------------+----------------------------------   F(1, 70)        =    232.39
       Model |  .050031725         1  .050031725   Prob > F        =    0.0000
    Residual |   .01507069        70  .000215296   R-squared       =    0.7685
-------------+----------------------------------   Adj R-squared   =    0.7652
       Total |  .065102415        71  .000916935   Root MSE        =    .01467

------------------------------------------------------------------------------
       lcust |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
  lntotemp12 |   1.224647   .0962394    12.73   0.000     1.032703     1.41659
       _cons |   3.202115   .4055417     7.90   0.000     2.393288    4.010943
-------------+----------------------------------------------------------------
         rho |  -.0108025
------------------------------------------------------------------------------
Durbin-Watson statistic (original)    2.021164
Durbin-Watson statistic (transformed) 1.993565
```

CLFP System Peak Demand Model

```
      Source |       SS           df       MS      Number of obs   =       382
-------------+----------------------------------   F(17, 364)      =    259.88
       Model |   2.7075761        17  .159269182   Prob > F        =    0.0000
    Residual |  .223080505       364  .000612859   R-squared       =    0.9239
-------------+----------------------------------   Adj R-squared   =    0.9203
       Total |   2.9306566       381  .007692012   Root MSE        =    .02476

--------------------------------------------------------------------------------
        lMWwoMS |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
----------------+---------------------------------------------------------------
            cdh |   .0019791   .0007083     2.79   0.005     .0005862    .0033719
          cdd60 |   .0048258   .0009546     5.06   0.000     .0029485    .0067031
            hdh |   .0007178   .0003331     2.16   0.032     .0000628    .0013728
          hdd60 |   .0006511   .0003106     2.10   0.037     .0000402     .001262
mnthcdd60perday |   .0078491   .0016518     4.75   0.000     .0046009    .0110973
       lntotemp |   .6704658   .0296946    22.58   0.000     .6120712    .7288603
             m2 |  -.0104943   .0068803    -1.53   0.128    -.0240245    .0030359
             m3 |  -.0561029   .0074336    -7.55   0.000     -.070721   -.0414847
             m4 |  -.1031688     .00717   -14.39   0.000    -.1172686   -.0890689
             m5 |  -.1075987   .0081318   -13.23   0.000    -.1235899   -.0916074
             m6 |  -.0583115   .0121855    -4.79   0.000    -.0822743   -.0343486
             m7 |  -.0386051   .0172689    -2.24   0.026    -.0725645   -.0046456
             m8 |  -.0577883   .0147434    -3.92   0.000    -.0867812   -.0287954
             m9 |   -.066601   .0111045    -6.00   0.000    -.0884381   -.0447638
            m10 |  -.0840245   .0082962   -10.13   0.000    -.1003389     -.06771
            m11 |  -.0293447    .006979    -4.20   0.000    -.0430688   -.0156205
            m12 |   .0229512   .0067193     3.42   0.001     .0097376    .0361648
          _cons |   2.265582   .1232518    18.38   0.000     2.023208    2.507957
--------------------------------------------------------------------------------
```

M. DATA CENTER IMPACT STUDY

Wyoming House Bill No. 67, enacted in 2010 and subsequently amended by Wyoming House Bill No. 117 the following year, exempted purchases and rentals of certain equipment for resident data centers from state sales and use tax.

The amended bill created two categories for these purchases and rentals, each with a specific list of qualifying equipment. To qualify for tax exemption, the aggregate purchase in each category must exceed $2 million. The data centers must be located in Wyoming.

Other requirements must be met for these transactions to be exempt from tax. Among these requirements are minimum initial capital investments and certification to create a minimum number of jobs.

This appendix contains a report from the Wyoming Department of Revenue, published in 2019, that describes these laws and their resultant economic impact on the state. Also included is a two-page summary from Cheyenne LEADS about the financial benefits realized from data centers located in Wyoming.

The Effects of the Sales and Use Tax Exemption For Qualifying Data Processing Services Center's Purchases and Rentals

Compiled by
the staff of the
Education and Taxability Section,
Wyoming Department of Revenue

and edited by
Terri Lucero, Administrator

Seventh Edition

2010, W.S. 39-15-105(a)(viii)(S) and W.S. 39-16-105(a)(viii)(H), as amended

Revenue, Department of
(011)
http://revenue.wyo.gov

Cheyenne, Wyoming 82002

November 22, 2019

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Overview

In the Wyoming Legislature 2010 Session Original House Bill No. 67 (Enrolled Act No. 31) was passed and signed by Governor Freudenthal into law on March 5, 2010. This act relates to taxation and revenue and provides for a sales and use tax exemption for the purchases and rentals of qualifying computer equipment including computers, servers, monitors, keyboards, storage devices and other peripherals, racking systems, cabling and trays that are necessary for the operation of a data processing services center when the aggregate purchase of the qualifying equipment exceeds two million dollars in any calendar year. The act provides for a reporting requirement and an effective date. This law took effect upon signature.

Subsequently House Bill No. 117 (Enrolled Act No. 17) was passed and signed by Governor Mead on February 18, 2011. This had the effect of amending and expanding the first Act. As it now reads, subject to meeting the applicable provisions of the exemption, the following purchases by a data processing services center (as defined in W.S. 39-15-101(a)(xliv)) are exempt:

> (I) The sales price paid for the purchase or rental of qualifying prewritten and other computer software, computer equipment including computers, servers, monitors, keyboards, storage devices, containers used to transport and house such computer equipment and other peripherals, racking systems, cabling and trays that are necessary for the operation of a data processing services center when the aggregate purchase of the qualifying equipment exceeds two million dollars ($2,000,000.00) in any calendar year;
>
> (II) The sales price paid for the purchase or rental of qualifying uninterruptable power supplies, back-up power generators, specialized heating and air conditioning equipment and air quality control equipment used for controlling the computer environment necessary for the operation of a data processing services center when the aggregate purchase of the qualifying equipment exceeds two million dollars ($2,000,000.00) in any calendar year;

This exemption is located within the "economic incentive" group of sales and use tax exemptions in the Wyoming statutes. [W.S. 39-15-105(a)(viii) and W.S. 39-16-105(a)(viii)] In order to avail themselves of the exemption a qualifying data processing services center must meet certain requirements.

In addition to having a physical location in the state where the qualifying equipment will be maintained and operated (until it is scheduled for replacement or until it has reached the end of its serviceable life) for Subparagraph (I) the qualifying data processing services center must make, or have made within the five years immediately preceding March 5, 2010, an initial capital investment of not less than five million dollars ($5,000,000) and for Subparagraph (II) the qualifying data processing services center must make, or have made within the five years immediately preceding April 1, 2011, an initial capital investment of not less than fifty million dollars ($50,000,000). Furthermore the data processing services center must have received certification from the Wyoming Business Council that the business has created or will create a number of jobs in Wyoming that is appropriate to the size and stage of development of the data processing services center as determined by the Wyoming Business Council.

Specific Requirements by Statute

Wyo. Stat. Ann. § 39-15-105(b)

> "The Wyoming business council, the department of workforce services and the department of revenue shall jointly report to the joint revenue interim committee on or before December 1 of each year that the exemption is in effect. If requested by the department of revenue, any person utilizing the exemption shall report to the department the amount of sales tax exempted, and the number of jobs created or impacted by the utilization of the exemption."

This report is to evaluate the cumulative effects of the exemption from initiation of the exemption and shall include:

(i) A history of employment in terms of the numbers of employees, full-time and part time employees, and rate of turnover classified by the 2007 edition, as amended, of the North American Industry Classification System (NAICS) code manufacturing section 31 – 33 from information collected by the Department of Employment;

(ii) A history of wages and benefits disaggregated by gender for each job category; and

(iii) A comprehensive history of taxes paid to the state of Wyoming.

Findings

This year represents the seventh year the Department of Revenue has requested information from companies potentially utilizing the exemption. A cover letter attached to the return instructed the respondents that once completed, the information could be mailed, faxed or emailed back to the Department of Revenue's Excise Tax Division. All of the respondents replied electronically.

For the calendar year ending December 2018, the Department reached out to seven entities that have been identified as data processing service centers in this State. This is one less than last year. Of those, the Department received responses from three, however one company indicated it did not make sufficient purchases to trigger the exemption and did not provide any additional information regarding purchases or employment. Of the two companies, both made sufficient purchases to utilize the exemption under part (I) but only one made sufficient purchases to trigger part (II).

Exemption Cost

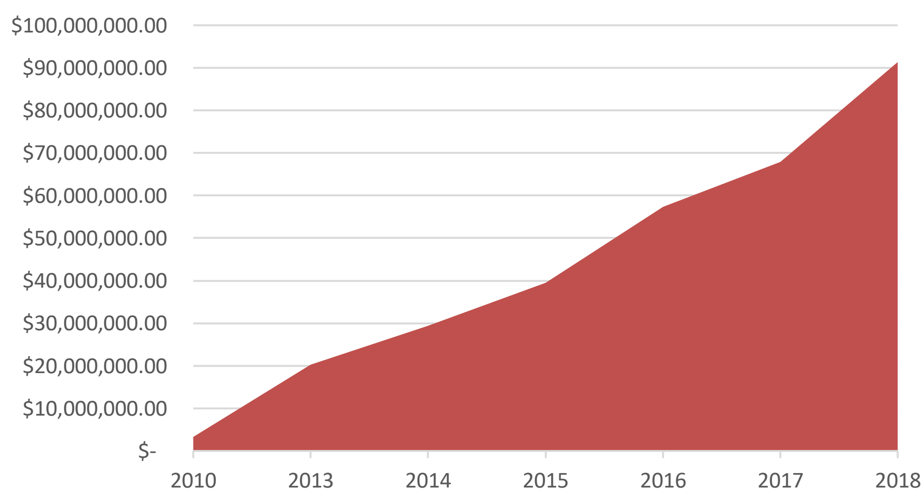
Companies claiming exemption on qualifying prewritten and other computer software, computer equipment including computers, servers, monitors, keyboards, storage devices, containers used to transport and house such computer equipment and other peripherals, racking systems, cabling and trays reported $423.5M in exempt purchases in 2018. In addition $11.9M in qualifying uninterruptable power supplies, back-up power generators, specialized heating and air conditioning equipment and air quality control equipment used for controlling the computer environment necessary for the operation of a data processing services center was made in 2018.

Applying an average 2018 tax rate of 5.39% this resulted in $23.47M in unrealized sales and use tax in 2018. This is more than double the amount of exempt purchases in 2017 and represents 25.7% of the exemption's total usage since its inception in 2010. Table 1 describes the total purchases and unrealized tax for each year. Table 2 graphically represents the cumulative effect of the exemption.

Table 1: Exempt Purchases and Unrealized Tax Revenue, 2010 - 2018

	Qualifying Exemption (I)	Qualifying Exemption (II)	Total Exempt Purchases	Unrealized Sales and Use Tax
2Q10 – 2Q13	$ 22,260,014.00	$ 40,845,160.00	$ 63,105,174.00	$ 3,319,332.15
3Q2013 – Yr End	$ 277,488,171.00	$ 38,647,960.00	$ 316,136,131.00	$ 16,976,510.23
2014	$ 162,583,622.00	$ 6,836,331.00	$ 169,419,953.00	$ 9,080,909.48
2015	$ 181,946,836.00	$ 5,904,642.00	$ 187,851,478.00	$ 10,106,409.52
2016	$ 319,517,743.00	$ 12,123,508.00	$ 331,641,251.00	$ 17,908,627.55
2017	$ 195,682,743.00	$ -	$ 195,682,743.00	$ 10,488,595.02
2018	$ 423,514,743.00	$ 11,903,520.00	$ 435,418,263.00	$ 23,469,044.38
Total	$1,582,993,872.00	$ 116,261,121.00	$1,699,254,993.00	$ 91,349,428.34

Table 2: Cumulative Unrealized Sales and Use Tax Revenue, 2010 - 2018



Employment

The total reported employee count is 220. This is an additional 23 positions over last year, of which 13 are new part time unskilled labor positions. By occupational classification, skilled workers make up the largest percentage of the workforce, accounting for 41.4%, or 91 positions in 2018. This is the same as in the preceding year. The second largest occupational classification is unskilled labor. In 2018, full and part time unskilled laborers filled 85 positions, making up 38.6% of the workforce. Unskilled labor grew in the workforce by more than 5% over 2017. Combined skilled and unskilled labor made up 80% of the workforce in 2018. Since 2013, skilled and unskilled workers have made up between 72 and 83% of the total workforce. Table 3 details the distribution of the workforce by occupational classification. Table 4 expresses this information as a percentage of the workforce.

Table 3: Workforce Distribution by Occupational Classification 2013 - 2018

	2013	2014	2015	2016	2017	2018
Supervisor / Manager	11	18	20	28	25	27
Administrative Svcs	20	4	3	3	2	2
Customer Svc	2	2	2	11	13	15
Skilled Labor	45	33	55	72	91	91
Unskilled Labor	38	49	64	95	66	85

Table 4: Workforce Distribution as a Percentage of Workforce, 2013 - 2018

	2013	2014	2015	2016	2017	2018
Supervisor / Manager	9.5%	17.0%	13.9%	13.4%	12.7%	12.3%
Administrative Svcs	17.2%	3.8%	2.1%	1.4%	1.0%	0.9%
Customer Svc	1.7%	1.9%	1.4%	5.3%	6.6%	6.8%
Skilled Labor	38.8%	31.1%	38.2%	34.4%	46.2%	41.4%
Unskilled Labor	32.8%	46.2%	44.4%	45.5%	33.5%	38.6%

Since 2015 women have occupied 9% of the workforce. By occupational classification in 2018 this breaks down to 2 administrative positions, 3 customer service positions and 16 positions as skilled labor. Historically women have not held any managerial/supervisory positions since 2016. Further since 2014 men have not held any administrative support positions. And for the first time, 2018 saw no unskilled labor positions held by women. Table 5 details the workforce distribution by occupational classification and gender from 2013 – 2018.

Table 5: Workforce Distribution by Occupational Classification and Gender, 2013 – 2018

	2013		2014		2015		2016		2017		2018	
	M	**F**	**M**	**F**	**M**	**F**	**M**	**F**	**M**	**F**	**M**	**F**
Supervisor / Manager	10	1	16	2	17	3	25	3	25	0	27	0
Administrative Svcs	16	4	0	4	0	3	0	3	0	2	0	2
Customer Svc	2	0	2	0	2	0	8	3	12	1	12	3
Skilled Labor	40	5	30	3	53	2	69	3	79	12	75	16
Unskilled Labor	35	3	44	5	59	5	88	7	63	3	85	0
Total	103	13	92	14	131	13	190	19	179	18	199	21
Percentage	88.8%	11.2%	86.8%	13.2%	91.0%	9.0%	90.9%	9.1%	90.9%	9.1%	90.5%	9.5%

Wage Earnings

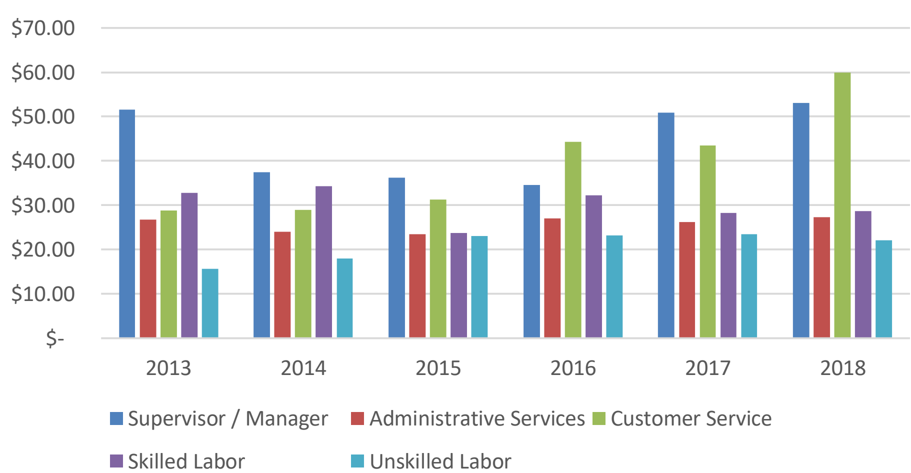
Between 2013 and 2018 wages have been inconsistent. For example supervisor/managers earned an hourly wage of $51.61 in 2013. This dipped to $34.60 by 2016. However by 2018 it had recovered to $53.14. Similarly administrative positions saw a similar dip, beginning at $26.81 in 2013, dropping to a low of $23.48 in 2015 and rebounding to $27.32 by 2018. In contrast unskilled labor positions earned an hourly wage of $15.72 in 2013 and saw a high of $23.45 in 2017 before dropping back down to $22.09 in 2018. Customer service positions saw the most change, beginning 2013 at $28.88/hour and increasing every year. By 2018, the average hourly wage was $59.87, more than double the wage only six years earlier. Table 6 details the average hourly wage per occupational classification and per year.

Table 6: Average Wage per Occupational Classification, 2013 - 2019

	2013	2014	2015	2016	2017	2018
Supervisor / Manager	$ 51.61	$ 37.49	$ 36.23	$ 34.60	$ 50.88	$ 53.14
Administrative Services	$ 26.81	$ 23.99	$ 23.48	$ 27.10	$ 26.23	$ 27.32
Customer Service	$ 28.88	$ 29.00	$ 31.30	$ 44.37	$ 43.51	$ 59.87
Skilled Labor	$ 32.74	$ 34.28	$ 23.68	$ 32.20	$ 28.27	$ 28.70
Unskilled Labor	$ 15.72	$ 17.99	$ 23.13	$ 23.23	$ 23.45	$ 22.09

Table 7 graphically represents the average hourly wage per occupational classification, per year. It may be important to note that the average hourly wage earned by customer service positions is higher than that earned by supervisor/managers.

Table 7: Average Wage by Occupational Classification, 2013 - 2018



Looking at gender, men and women frequently do not hold similar positions. Men have exclusively held supervisory or managerial positions since 2017. Similarly women have held all of the administrative positions since 2014. Customer service positions, originally held only by men, only saw the addition of women starting in 2016. The two employment classifications that have had the most consistent employment by both genders is skilled and unskilled labor. Table 8 depicts the wage difference for skilled labor and Table 9 depicts the same for unskilled labor.

Table 8: Average Wage for Skilled Labor Positons, year over year, by Gender

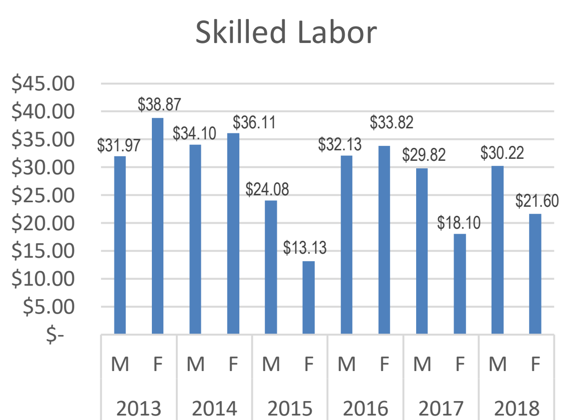
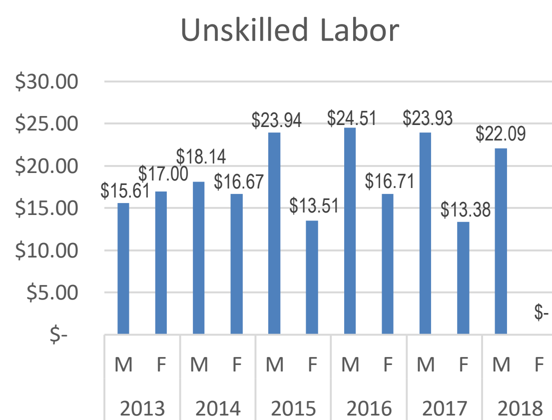


Table 9: Average Wage for Unskilled Labor Positions, year over year, by Gender



Survey respondents report similar if not slightly higher wages than the statewide average. In 2018, the Wyoming Department of Workforce Services ("DWS") reported persons in managerial positions earned an average of $45.29/hour while survey responses indicated an average of $53.14/hour. Similarly DWS reported skilled laborers earned an average wage of $29.48 whereas survey responses indicated a wage of $28.70/hour. DWS reported unskilled labor at $20.21/hour and the survey responses indicated $22.09 per hour. While this has remained relatively constant throughout the period, we would be remiss if we did not point out the exceptional difference for those in administrative or customer service positions. DWS reported persons in these positions earned an average of $18.34 and $15.73 respectively. Survey responses indicates those in administrative positions earned $27.32/hour and customer service positions earned $59.87/hour. Unfortunately it is unclear if the occupational classification as reported by DWS and that of survey responses are of similar duties and responsibilities.[1] Table 10 demonstrates the average annual wage per responses versus the Wyoming average.

[1] *Wyominng Occupational Employment and Wages March 2018* as reported by the Wyoming Department of Workforce Services', Research and Planning Section (https://doe.state.wy.us/lmi/lewismarch2018eci/toc000.htm) retrieved 10/1/2019.

Table 10: Average Annual Wage per Occupational Classification as reported by Survey Responses compared to Average Statewide Wage for Similar Occupational Classification

		2013	2014	2015	2016	2017	2018
Managerial	Response	$ 51.61	$ 37.49	$ 36.23	$ 34.60	$ 50.88	$ 53.14
11-3021	WY Average	$ 39.83	$ 40.05	$ 40.24	$ 42.52	$ 42.71	$ 45.29
Administrative	Response	$ 26.81	$ 23.99	$ 23.48	$ 27.10	$ 26.23	$ 27.32
43-3031	WY Average	$ 16.81	$ 17.31	$ 17.37	$ 17.44	$ 17.94	$ 18.34
Customer Service	Response	$ 28.88	$ 29.00	$ 31.30	$ 44.37	$ 43.51	$ 59.87
43-4051	WY Average	$ 13.13	$ 13.52	$ 13.80	$ 14.32	$ 15.03	$ 15.73
Skilled Labor	Response	$ 32.74	$ 34.28	$ 23.68	$ 32.20	$ 28.27	$ 28.70
15-0000	WY Average	$ 27.19	$ 27.34	$ 27.71	$ 28.43	$ 28.52	$ 29.48
Unskilled Labor	Response	$ 15.72	$ 17.99	$ 23.13	$ 23.23	$ 23.45	$ 22.09
49-2011	WY Average	$ 19.42	$ 18.96	$ 18.43	$ 17.48	$ 18.53	$ 20.21

Benefits

Consistent with every year surveyed, all companies employing in this field reported a full benefits package including medical and dental insurance, a prescription plan, a vision plan and retirement savings plans for full time employees. However part time employees did not receive any benefit package.

Turnover

Turnover rates within the industry are relatively low compared to the Wyoming average. In 2018, like the year before, no turnover was reported in administrative or customer service positions. Skilled labor reported a 4.0% turnover rate, unskilled labor 6.0% and managers 8.0%. Compared to the 29.6% average turnover rate for 2018Q1 through 2018Q3 across all industries employees tend to enjoy more job stability.[2]

Survey Costs

Due to the limited number of businesses contacted for this report, the cost to mail was nominal. As a result, the primary expense associated with this report is the time spent following up with the respondents and reviewing and analyzing the data received as well as the preparation of this report. The Department estimates office personnel expended 40 to 50 hours over the course of several weeks on this endeavor.

[2] Turnover rates for 2017Q3 and prior obtained previously and cited in previous editions. 2017Q4 obtained from *Trends*, Vol 55 No 7, Wyoming Department of Workforce Services, Research& Planning office. 2018Q1 obtained from *Trends*, Vol 55 No 10, Wyoming Department of Workforce Services, Research& Planning office. 2018Q2 obtained from *Trends*, Vol 56 No 1, Wyoming Department of Workforce Services, Research& Planning office. 2018Q3 obtained from *Trends*, Vol 56 No 4, Wyoming Department of Workforce Services, Research& Planning office.

Wyoming Business Council Regional Project Assessment System (RPAS)

Data center tax incentive economic analysis

The RPAS model has been developed for Wyoming by Applied Economics, LLC of Phoenix, Arizona, www.aeconomics.com. The model identifies measurable effects associated with either a specific activity in a specific location or the value of economic and revenue impacts of existing businesses. The model has multipliers for 66 NAICS-based industry types based on Minnesota IMPLAN group data. It provides the value of additional output for job creation in addition to the direct jobs created and measures direct and indirect property and sales tax benefits to local and state revenues.

- Jobs, wages and output:
  - There has been significant growth in the last several years in data hosting jobs and wages.
  - Not all jobs created are reflected in the numbers below. Data centers often contract out a significant amount of work.
  - The economic output from these direct wages is significant. The numbers below do not include indirect economic output of suppliers.

Year	Workforce	Average Wage	Total Direct Wages	Output from Employment Income
2010-2012	15	$ 51,798	$ 776,970	$ 2,231,226
2013	116	$ 57,955	$ 6,722,780	$ 19,305,821
2014	106	$ 55,758	$ 5,910,348	$ 16,972,759
2015	144	$ 52,580	$ 7,571,520	$ 21,743,750
2016	209	$ 60,344	$ 12,611,896	$ 36,217,608
2017	198	$ 55,465	$ 10,956,288	$ 31,463,195
2018	202	$ 66,655	$ 13,471,438	$ 29,124,993
Totals			$ 58,021,240	$ 157,059,352

* The year, workforce numbers and average wage are from data available at Department of Workforce Services, Research and Planning Labor Market Information, Quarterly Census of Employment and Wages.

* Output represents the total economic activity generated. It is derived from employment income and calculated by the WBC economic impact model. The inputs are direct employment numbers and average wages. The model then calculates additional multipliers of the wages rolling over in the community. Real estate market valuation for tax purposes

*2018 numbers forward are calculated using an updated RPAS model

The market valuation of data centers shows a trend of sudden growth, mainly from additional investment by Microsoft in its Cheyenne campus.

	2019	2018	2017	2016	2015	2014	2013
Greenhouse Data	8,127,826	7,997,420	7,914,648	8,007,395	7,792,972	351,654	
Microsoft	1,152,561,644	90,092,646	91,354,921	89,767,721	211,623	168,703	164,473
EchoStar	20,527,463	25,514,621	83,634,989	4,492,384	4,492,384	4,492,384	4,492,384
Mountain West	1,333,461	1,377,561	879,690	931,730	963,010	939,550	568,540
Ptolemy	1,318,798	1,577,172	1,494,228	1,477,077	1,598,498	1,530,624	1,469,670
Totals	1,183,869,192	126,559,420	185,278,476	104,676,307	15,058,487	7,482,915	6,695,067

The following numbers do not include electricity tax or construction sales tax. However, data centers generate significant construction sales tax, electricity sales tax, property tax and indirect sales tax.

Year	Annual Capital Expenditures	Local Real Property Tax	Local Personal Property Tax	Local Sales Taxes	Total Local Taxes	State Sales Tax	Total State and Local Taxes	Unrealized Revenue from Sales Taxes	Net Return to State and Local Governments
2012	63,105,174	73,195	343,032	4,777	421,004	13,451	434,455	3,319,332	(2,884,877)
2013	316,136,131	342,551	2,003,937	41,330	2,387,818	116,386	2,504,204	16,976,510	(14,472,306)
2014	164,119,341	412,285	2,528,809	36,335	2,977,429	102,321	3,079,750	9,080,909	(6,001,159)
2015	187,851,478	1,152,648	2,976,447	46,547	4,175,642	131,080	4,306,722	10,106,410	(5,799,688)
2016	319,500,000	2,502,173	3,949,519	77,534	6,529,226	218,340	6,747,566	17,908,627	(11,161,061)
2017	185,638,850	3,265,716	4,035,409	67,356	7,368,481	189,678	7,558,159	10,488,595	(2,930,436)
2018	435,418,263	10,854,450	5,573,896	79,785	16,508,131	227,958	16,736,089	23,469,044	(6,732,955)
Totals	1,236,350,974	18,603,018	21,411,049	353,664	40,367,731	999,214	41,366,945	91,349,427	(49,982,482)

- Approximately half of the property tax supports local school mill levies
- Direct and indirect property and sales tax is calculated by the WBC economic impact model. The inputs are assessed property valuation and equipment capital expenditures. The model then calculates the direct property and sales tax paid to local and state. It also creates and calculates multipliers for direct employees and indirect employment increase in their property and sales tax spending.

REMI Analyses: Economic Impacts

[Please note the following narrative below references the economic impacts of three separate sales and use tax exemptions. For clarity and ease of reading we have taken the liberty of removing those comments not specifically related to the Sales and Use Tax exemption for qualifying data processing services center's purchases and rentals.]

The analyses of the economic impacts of the sales and use tax exemptions for (1) purchases of machinery and machine tools used directly and predominantly in manufacturing, for (2) purchases and rentals of qualifying computer equipment necessary for the operation of a data processing center, and for (3) the sales/purchases of tangible personal property or services performed for the repair, assemble, alteration, or improvement of railroad rolling stock was prepared using the

Regional Economic Models, Inc. (REMI) PI+ model. REMI PI+ is the next generation Policy Insight model built exclusively for Wyoming. It is an integrated model that combines the best features of the input-output, general equilibrium, econometric, and economic geography methodologies. PI+ is also a dynamic rather than a static model allowing for year-by-year analysis of the total regional effects of any specific policy initiative.

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Table 2: Economic Impact of **Sales & Use Tax Exemption Removal** for Data Centers

Category	Years					Average
(Change from Baseline)	2018	2019	2020	2021	2022	2018-2030
Total Employment - Jobs	-42	-63	-78	-88	-94	-88
Information	-4	-7	-10	-12	-13	-14
Finance & Insurance	-4	-7	-9	-11	-12	-12
Retail Trade	-6	-8	-9	-10	-10	-10
Construction	-7	-11	-13	-13	-13	-9
All Other	-21	-30	-37	-42	-45	-43
Population - Individuals	-16	-31	-46	-60	-74	-80
Wages and Salaries	-$2.3	-$2.9	-$3.4	-$3.8	-$4.1	-$4.1
Personal Income	-$4.5	-$5.3	-$6.2	-$6.9	-$7.4	-$7.6
Disposable Personal Income	-$4.0	-$4.8	-$5.6	-$6.2	-$6.7	-$6.8
Gross Domestic Product	-$3.5	-$5.3	-$6.6	-$7.6	-$8.2	-$7.9
Output	-$5.7	-$8.7	-$11.0	-$12.6	-$13.6	-$13.1
Note: All dollar amounts are expressed as millions of fixed (2017) dollars.						

The economic impact of the **removal of the sales tax exemption** for purchases and rentals of qualifying computer equipment necessary for the operation of a data processing center was modeled in REMI as an increase in the production costs for the data center industry of $15.0 million per year beginning in 2018 (see Table 2). This exemption removal would result in an average annual loss of 88 jobs and a decrease in GDP of $7.9 million per year over the period of 2018 to 2030 when compared to the baseline scenario.

The information, finance & insurance, retail trade, and construction sectors will incur the majority of the job losses. Direct job losses are attributed to information, finance & insurance, and construction sectors while the retail trade sector will be adversely impacted from the decline in disposable personal income.

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Key Definitions

Total Employment comprises estimates of the number of non-farm jobs, full-time plus part-time, by place of work. Full-time and part-time jobs are counted at equal weight. Includes direct, indirect, and induced jobs.

Population reflects mid-year estimates of people, including survivors from the previous year, births, special populations, and three types of migrants (economic, international, and retired).

Wages and Salaries are the monetary remuneration of employees, including the compensation of corporate officers; commissions, tips, and bonuses; voluntary employee contributions to certain deferred compensation plans, such as 401(k) plans; and receipts in kind that represent income. Wages and salaries disbursements are affected by changes in Wage Rate and Employment.

Personal Income is the income that is received by all persons from all sources. It is calculated as the sum of wage and salary disbursements, supplements to wages and salaries, proprietors' income with inventory valuation and capital consumption adjustments, rental income of persons with capital consumption adjustment, personal dividend income, personal interest income, and personal current transfer receipts, less contributions for government social insurance.

Disposable Personal Income equals personal income minus personal taxes.

Gross Domestic Product or **GDP** is the market value of goods and services produced by labor and property. It is often referred to as "value added" and is equal to its gross output (sales or receipts and other operating income, plus inventory change) minus its intermediate inputs (consumption of goods and services purchased from other industries or imported).

Output is the amount of production, including all intermediate goods purchased as well as value-added (compensation and profit). Output can also be thought of as sales or supply or simply price multiplied by quantity (P×Q).

About the REMI PI+ Model

The REMI PI+ model incorporates aspects of four major modeling approaches: **Input-Output**, **General Equilibrium**, **Econometric**, and **Economic Geography**. Each of these methodologies has distinct advantages as well as limitations when used alone. The REMI integrated modeling approach builds on the strengths of each of these approaches.

The REMI model at its core has the inter-industry relationships found in **Input-Output models**. As a result, the industry structure of a particular region is captured within the model, as well as transactions between industries. Changes that affect industry sectors that are highly interconnected to the rest of the economy will often have a greater economic impact than those for industries that are not closely linked to the regional economy.

General Equilibrium is reached when supply and demand are balanced. This tends to occur in the long run, as prices, production, consumption, imports, exports, and other changes occur to stabilize the economic system. For example, if real wages in a region rise relative to the U.S., this will tend to attract economic migrants to the region until relative real wage rates equalize. The general equilibrium properties are necessary to evaluate changes such as tax policies that may have an effect on regional prices and competitiveness.

REMI is sometimes called an "**Econometric model**," as the underlying equations and responses are estimated using advanced statistical techniques. The estimates are used to quantify the structural relationships in the model. The speed of economic responses is also estimated, since different adjustment periods will result in different policy recommendations and even different economic outcomes.

The **New Economic Geography** features represent the spatial dimension of the economy. Transportation costs and accessibility are important economic determinants of interregional trade and the productivity benefits that occur due to industry clustering and labor market access. Firms benefit having access to a large, specialized labor pool and from having access to specialized intermediate inputs from supplying firms. The productivity and competitiveness benefits of labor and industry concentrations are called agglomeration economies, and are modeled in the economic geography equations.

The primary national, state, and county data source for REMI PI+ is the Bureau of Economic Analysis (BEA) State Personal Income (SPI) and Local Area Personal Income (LAPI) series (which also include employment and total population at both the state and county level). REMI also relies on numerous other data sources including the Bureau of Labor Statistics, Energy Information Administration, Center for Disease Control and Prevention, National Center for Health Statistics, and the Department of Defense. *Source: remi.com.*

REMI REGIONAL ECONOMIC MODELS, INC.

Data Centers in Wyoming

Data Centers are good for Wyoming as they bring high capital investment, high wage technology jobs, low fiscal impact on local and state government services and diversify the economy. Additionally, hundreds of construction workers are employed during the development of data centers.

It is a growing industry for Wyoming as at least 3 new centers are considering Wyoming.

4 - Data Centers in LEADS business parks[1]

$82M - Annual contribution to Wyoming Gross Domestic Product[2]

209 - Primary jobs at those data centers today[3]

148 - Additional jobs in support occupations, not including construction employment[4]

$1.5B+ - Capital investment since opening[5]

$82.6M - Total wages paid to employees since coming to Wyoming[6]

$18.7M - Sales Taxes paid on power since opening[7]

$40.6M - Property taxes paid since opening[8]

32 other states offer data center tax exemptions

Cheyenne **LEADS**
The Cheyenne-Laramie County Corporation for Economic Development

FOR ADDITIONAL INFORMATION CONTACT:
Betsey Hale, CEcD - CEO Cheyenne LEADS
(307)630-2179

1. Microsoft, Lunavi, EchoStar/Dish, The National Center for Atmospheric Research
2. University of Wyoming CBEA
3. UW CBEA Quarterly Census of Employment and Wages
4. REMI and University of Wyoming
5. Laramie County Building Permit Valuations and companies
6. REMI and University of Wyoming
7. REMI and University of Wyoming
8. Laramie County Assessor

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4 Data Centers in Cheyenne LEADS business parks[1]

209 Primary jobs at those data centers today[3]

148 Additional jobs in support occupations, not including construction employment[4]

Over $1.5B Capital investment since opening[5]

$82.6M Total Wages paid to employees since coming to Wyoming[6]

$40.6M Property taxes paid since opening[8]

$18.7M Sales Taxes paid on power[7]

32 Other states offer data center tax exemptions

Cheyenne **LEADS**
The Cheyenne-Laramie County Corporation for Economic Development

FOR ADDITIONAL INFORMATION CONTACT:
Betsey Hale, CEcD - CEO Cheyenne LEADS
(307)630-2179

1. Microsoft, Lunavi, EchoStar/Dish, The National Center for Atmospheric Research
2. University of Wyoming CBEA
3. UW CBEA Quarterly Census of Employment and Wages
4. Regional Economic Models Inc. and University of Wyoming
5. Laramie County Building Permit Valuations and companies
6. Regional Economic Models Inc. and University of Wyoming
7. Regional Economic Models Inc. and University of Wyoming
8. Laramie County Assessor

N. 2021 IRP MODELING SUMMARY

Hitachi ABB Power Grids (HAPG) completed capacity expansion, production cost, and stochastic modeling for several scenarios for the 2021 IRP. HAPG evaluated ten scenarios for Cheyenne Light, nine scenarios for Black Hills Power, and six scenarios for a joint plan. All scenarios, except one, were run to develop candidate resource portfolios. This process is discussed in detail in Chapter 8.

Modeling and analysis was run through the HAPG Capacity Expansion and Portfolio Optimization modules. Assumptions were derived from the Fall 2020 Reference Case.

This appendix describes the scope, assumptions, modeling and analysis, and results that form the foundation of the 2021 IRP.

REPORT

2021 Integrated Resource Plan Modelling Summary for Cheyenne Light Fuel & Power, Black Hills Power and a Black Hills Power and Cheyenne Light Fuel & Power Joint System

PREPARED FOR

Black Hills Corporation

PREPARED BY

Hitachi ABB Power Grids Advisory Services

May 2021

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HITACHI ABB

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1 Executive Summary

Hitachi ABB Power Grids (HAPG) was retained by Black Hills Corporation (BHC), to provide analytical services in support of Cheyenne Light Fuel & Power's (CLF&P) and Black Hills Power's (BHP) 2021 Integrated Resource Plans (IRP). These services included completing capacity expansion, production cost and stochastic modeling for a variety of scenarios for each utility and a Joint System. HAPG's Energy Market Advisors team (EMA) evaluated ten scenarios for CLF&P's system, nine scenarios for BHP's system and six scenarios for the Joint System. As part of these services, Black Hills' Capacity Expansion (CE) and Portfolio Optimization (PO) databases were updated to include the Fall 2020 Reference Case assumptions and other modeling assumptions provided by BHC. EMA used the updated CE and PO databases to complete capacity expansion modeling for all three IRPs. Table 1 includes a description of the variables that were revised for each scenario and identifies the portfolios that were developed for each utility and the Joint System for the different scenarios[1].

Table 1 Portfolio Descriptions

Scenario	Load Growth	Electric Price	Gas Price	Carbon Cost Adder	Resource Selection	Portfolios
1	Median	Median	Median	None	Economic	C1, B1, J1
2	Median	CO_2 Tax	Median	CO_2 Tax	Economic	C2, B2, J2
3	Median	Low	Low	None	Economic	C3, B3, J3
4	Median	High	High	None	Economic	C4, B4, J4
5	Low	Median	Median	None	Economic	C5, B5, J5
6	High	Median	Median	None	Economic	C6, B6, J6
7	High + Step	Median	Median	None	Economic	C7, B7
8	Median	Median	Median	None	10 MW BESS	C8, B8
9	Median	Median	Median	None	Carbon Capture	C9
10	Median	Median	Median	ACP	C2, B2 Portfolio	C10, B9

EMA then incorporated the portfolios developed by the Capacity Expansion model runs into the PO database and ran PO simulations that included each scenario's portfolio and median assumptions for load growth, electric prices and fuel prices and no carbon cost adder.

[1] CLF&P portfolios are identified as C1 through C10, BHP portfolios are identified as B1 through B9 and the Joint System portfolios are identified as J1 through J6.

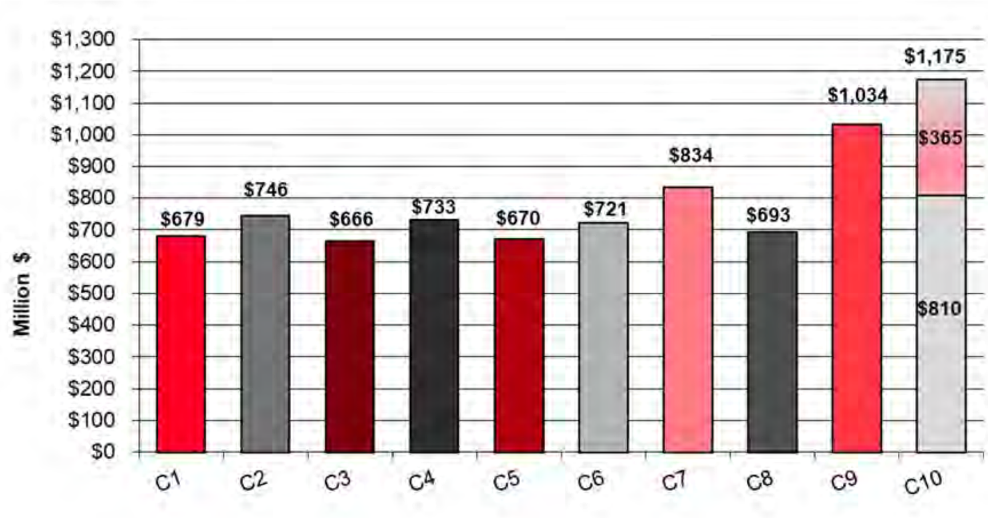
In response to recently proposed regulatory requirements, BHC requested that EMA model a CLEAN Future Scenario (Scenario10). For this scenario EMA completed production cost modelling using the portfolio developed in Capacity Expansion modelling for Portfolios C2 and B2 and applied the market prices and CO_2 Taxes from the Fall 2020 North American Power Reference Case CO_2 Tax Scenario, in lieu of the median assumptions that were used in the other PO simulations. The results from this production cost model were then modified to reflect Alternative Compliance Payments as proposed by BHC's Environmental Department rather than the CO_2 emission costs calculated using the CO_2 Tax forecast included in the Fall 2020 North American Power Reference Case CO_2 Scenario.

Next, EMA performed annual rate making to meet a target return on rate base specified by each utility. CLF&P's target return on rate base was set at 7.98%, BHP's was set at 7.76% and 7.85% was used for the Joint System. The study period for all the modelling was 2021-2040.

Lastly, EMA completed stochastic modeling for seven of BHP's nine portfolios and for seven of CLF&P's ten portfolios. Stochastic modeling was not completed for the Joint System. EMA used its Strategic Planning (SP) Corporate Finance module to complete the financial, rate making and risk simulations.

CLF&P's results, measured by the 20-year PVRR of each portfolio of the production cost, financial and rate making modeling are shown in Figure1. Portfolio 10 breaks out the ACP revenue requirements of $365 million.

Figure1 CLF&P Portfolios – Deterministic PVRR (2021-2040)



(Source: Energy Market Advisors)

As mentioned previously, BHP modelling included evaluation of nine portfolios with a target return on rate base of 7.76%. Figure 2 shows the PVRR for the BHP portfolios. Portfolio 10 breaks out the ACP revenue requirements of $91 million.

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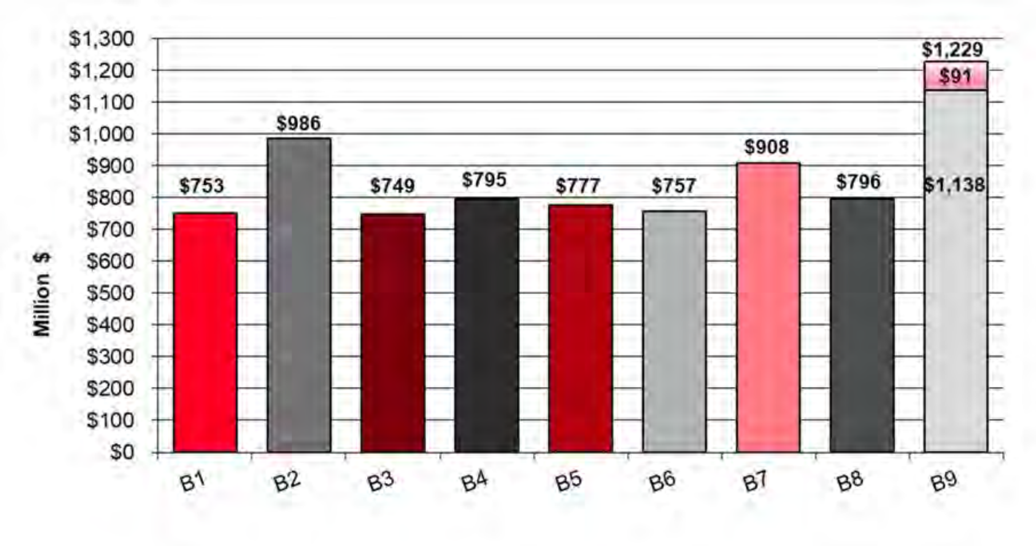
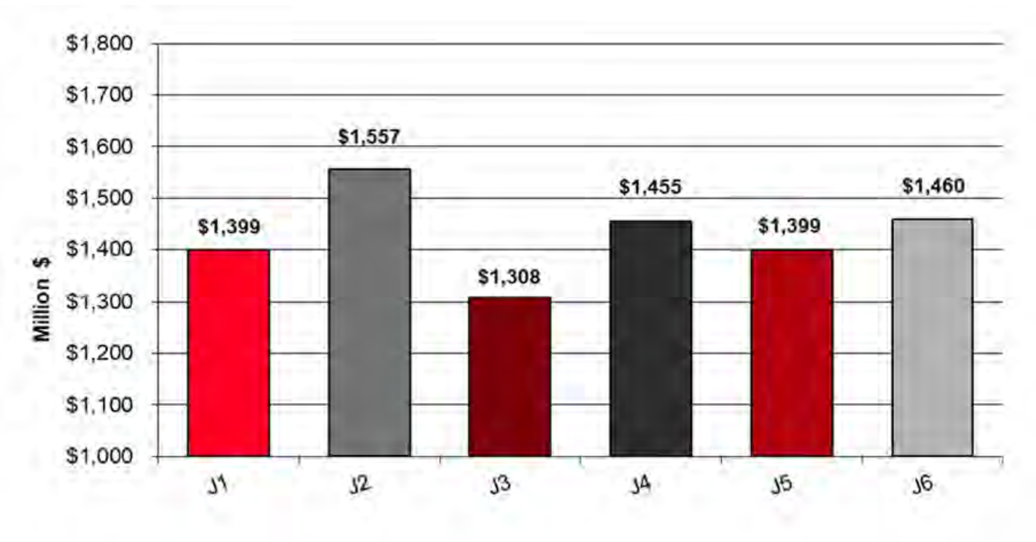
Figure 2 BHP Portfolios – Deterministic PVRR (2021-2040)



(Source: Energy Market Advisors)

Finally, the Joint System modelling included six portfolios with a target return of 7.85% on rate base. Figure 3 shows the PVRR for the six Joint System portfolios.

Figure 3 Joint System Portfolios – Deterministic PVRR (2021-2040)



(Source: Energy Market Advisors)

2 Scope of Study

EMA was retained by BHC, to provide analytical services in support of CLF&P's, BHP's and the Joint System's 2021 Integrated Resource Plans. As part of these services, EMA updated BHC's CE and PO database to include assumptions necessary to complete capacity expansion and production cost simulations for Base Plans as well as several BHC specified scenarios. Once the databases were updated EMA performed capacity expansion and production cost modelling as well as risk, financial, and rate making simulations using the SP financial model.

2.1 Develop Base Case and Scenario Data Inputs

EMA used data supplied by BHC to model BHP's, CLF&P's and the Joint System's entire portfolio of conventional and renewable resources, both existing and proposed, in Capacity Expansion. BHC also supplied information needed to model loads including demand-side resources that will be implemented during the planning horizon.

EMA updated BHC's database with the natural gas price forecast and electric market price forecast from the Fall 2020 North American Power Reference Case which includes a long-term forecast of the North American power, fuels, and environmental markets. Forecasts of future conditions in these markets are based on fundamentals of demand and supply in the respective markets. Energy Market Advisors examine the interaction between fuel supply and demand, electric demand, electric supply including current thermal and renewable additions and retirements, and environmental regulation, to develop a forecast for all markets. EMA starts with Power Grids' Velocity Suite for load forecasts, generating unit characteristics, new entrants, and proposed retirements. Additional information is based on EMA's research, as well as fuels data from a third-party vendor (Rystad). This information is entered into our proprietary Integrated Model, which helps to develop natural gas prices, coal prices, emission prices, and capacity expansion, based on the interactions between these individual markets. Finally, the quantities are entered in the Power Grids' PROMOD model to determine the final electric energy prices.

BHC selected the CO-W market area Market Clearing Price (MCP) forecast for economy energy market prices and the AZ-PV market area for seasonal firm market prices in all three models. Natural gas pricing was derived from the NG-Rockies and NG-Colorado burnertip forecasts for all three models.

The Fall 2020 North American Power Reference Case assumes CO_2 emission costs for the RGGI states, Alberta, British Columbia and California only. Therefore, no CO_2 emission costs were included in the three systems' median assumptions.

EMA used the Fall 2020 North American Power Reference Case High Gas, Low Gas and CO_2 Tax Scenario forecasts for natural gas prices, market prices and CO_2 emission prices to develop inputs for the IRP Scenario modelling.

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2.2 Capacity Expansion Screening

EMA used the CE model to completely enumerate all possible combinations of resource expansion plans for each scenario run. This powerful screening tool uses a Mixed Integer Linear Programming (MILP) technique to determine the optimal selection of resource expansion plans including sizing and timing while maintaining a 15% reserve margin with a decision criterion of minimizing the present value of revenue requirements (PVRR). The results of the CE plans were passed to the PO and SP models as part of the portfolio, risk, financial, and rate making simulations.

Capacity Expansion plans were created using CE for ten CLF&P portfolios, nine BHP portfolios and six Joint System portfolios. Capacity Expansion was not utilized for the CLEAN Future scenarios.

2.3 Production Cost Modelling (Portfolio Simulation)

Production cost modelling was completed using PO to dispatch the resource portfolios selected from the capacity expansion modelling results and determine the production cost of each expansion plan. This step involved running PO simulations that included each scenario's portfolio and median assumptions for load growth, electric prices and fuel prices and no carbon cost adder. Production costs were calculated using PO for all ten CLF&P portfolios, nine BHP portfolios and six Joint System portfolios. The production cost modelling results were then passed to the financial model.

2.4 Financial Simulation and Rate Making

The production cost results from PO were passed to the financial model where they were used in the portfolio, risk, financial, and rate making simulations. EMA used SP to perform incremental financing. The revenue driver was return on rate base. Financial statements were developed for the deterministic and stochastic runs using PO production cost results. Stochastic results included 50 draws. Capital cost draws were developed in SP and integrated with the production results.

Financial statements were used to calculate Present Value of Revenue Requirements. Risk profiles, trade-off diagrams and Value at Risk charts were produced from the financial results.

EMA performed annual rate making to meet each utility's targeted return on rate base by increasing or decreasing the annual revenue requirements for both deterministic and stochastic results. Annual financial statements were developed for all plans.

3 Assumptions

3.1 Introduction

The Energy Market Advisors (EMA) team is part of the HAPG Energy Market Intelligence solution area that provides tools and analysis around market and transmission modeling, analysis, and price forecasting to support investment decisions, regulatory compliance, trading, energy operations, and renewable integration.

The North American Power Reference Case product, published twice a year by the EMA team, is an assessment of conditions and trends in power, fuels, renewables, and environmental markets in North America. The product includes a long-term forecast of future conditions in these markets based on the fundamentals of demand and supply and are developed by utilizing HAPG's widely used data intelligence product called Velocity Suite, HAPG's proprietary capacity expansion model called Integrated Model, and HAPG's long-established production cost model called PROMOD®.

3.2 Natural Gas

The natural gas forecasts used in the BHP and CLF&P modelling were based on EMA's Fall 2020 North American Power Reference Case long-term forecasts. Natural gas pricing was derived from the NG-Rockies and NG-Colorado burnertip forecasts for BHP and CLF&P. Thermal units located in Cheyenne, Wyoming were assigned the NG-Rockies burnertip forecast while the NG-Colorado burnertip forecast was assigned to thermal generation located in Wyoming and South Dakota. Regional gas basis adders that are included in the Reference Case forecasts and CLF&P and BHP specific pipeline and transport costs were added to the EMA natural gas price forecast[2]. The annual Henry Hub gas price forecast is shown in Figure 4, and the monthly price forecast is summarized in Table 2.

[2] The published HAPG natural gas forecasts were converted to nominal dollars using a 1.5% escalation rate.

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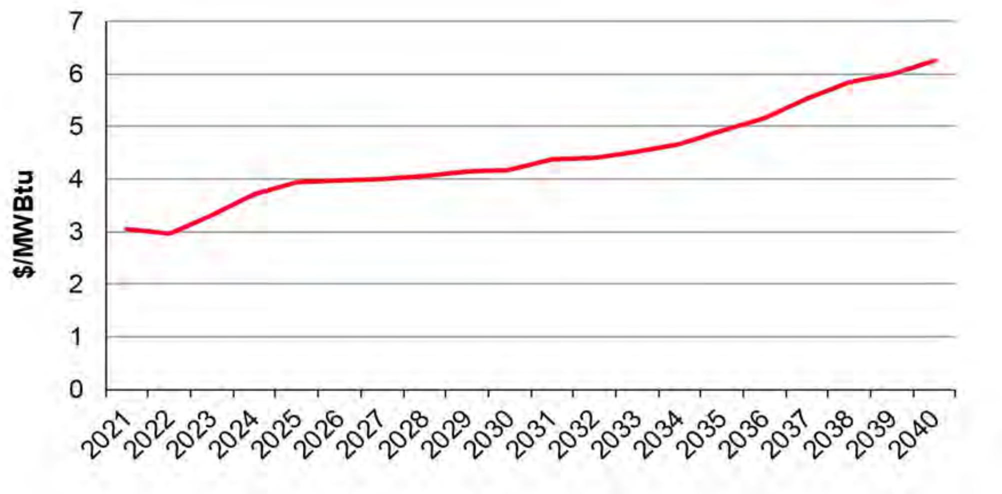
Figure 4 Annual Henry Hub Natural Gas Price



(Source: Energy Market Advisors)

Table 2 Monthly Henry Hub Natural Gas Price ($/MMBtu)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2021	3.42	3.37	3.23	2.87	2.81	2.84	2.88	2.89	2.88	2.91	2.97	3.11
2022	3.22	3.17	3.00	2.62	2.62	2.70	2.78	2.84	2.88	2.94	3.06	3.23
2023	3.32	3.34	3.22	3.10	3.13	3.17	3.22	3.25	3.26	3.29	3.42	3.58
2024	3.70	3.61	3.54	3.63	3.64	3.64	3.67	3.67	3.65	3.65	3.82	3.93
2025	4.03	4.02	3.82	3.83	3.83	3.86	3.89	3.89	3.86	3.85	3.94	4.11
2026	4.12	4.12	3.87	3.84	3.85	3.86	3.90	3.91	3.87	3.87	4.03	4.11
2027	4.14	4.12	3.90	3.85	3.85	3.86	3.88	3.89	3.87	3.88	4.09	4.12
2028	4.14	4.05	3.95	3.93	3.93	3.94	3.96	3.97	3.95	3.96	4.13	4.24
2029	4.26	4.26	4.06	4.01	4.02	4.05	4.06	4.07	4.06	4.04	4.18	4.25
2030	4.31	4.28	4.06	4.05	4.06	4.07	4.07	4.08	4.08	4.08	4.30	4.41
2031	4.49	4.44	4.26	4.23	4.24	4.26	4.29	4.30	4.26	4.27	4.43	4.50
2032	4.54	4.43	4.34	4.27	4.28	4.31	4.31	4.32	4.30	4.31	4.47	4.60
2033	4.67	4.64	4.40	4.38	4.38	4.39	4.41	4.41	4.40	4.41	4.61	4.74
2034	4.79	4.75	4.53	4.50	4.51	4.52	4.54	4.55	4.53	4.54	4.79	4.95
2035	5.09	4.98	4.75	4.77	4.78	4.82	4.84	4.86	4.83	4.81	5.06	5.19
2036	5.34	5.11	4.97	5.01	5.02	5.03	5.07	5.07	5.04	5.05	5.34	5.48
2037	5.67	5.55	5.24	5.39	5.40	5.41	5.48	5.49	5.43	5.43	5.58	5.79
2038	5.97	5.83	5.54	5.67	5.67	5.75	5.82	5.85	5.76	5.71	5.87	6.05
2039	6.27	6.08	5.73	5.79	5.80	5.87	5.96	5.97	5.88	5.83	6.02	6.17
2040	6.48	6.18	5.90	6.08	6.09	6.19	6.27	6.28	6.19	6.13	6.19	6.50

(Source: Energy Market Advisors)

To derive the NG Rockies and NG Colorado burner tip forecasts, EMA first aggregates regional basis prices at major trading hubs. Natural gas prices for the first 12 months of the forecast are driven by Henry Hub futures market prices plus a basis hub differential forward price. For the following 36 months of the forecast period (months 13-48), EMA blends the futures market price expectations with the long-term fundamental forecast, so that by the end of this period the gas price forecasts are consistent. EMA uses a cost-minimization linear program model of gas supply and demand.

3.3 Oil Prices

BHP's fleet includes five, two MW each, diesel units that operate primarily during extreme load hours or when other units in the fleet experience unplanned outages. The No.2 Distillate price forecast from the 2020 Fall Reference Case Base Case was used as the fuel price forecast for these units.

U.S. crude oil prices are based on conditions in the world oil market. Based on extensive prior analysis, EMA believes that the feedback to the world oil market from the markets represented in the North American forecast, i.e., power, natural gas, coal, and emissions, is extremely weak. Moreover, the effects on the world oil market of the types of policies or exogenous events that might be modeled, such as a CO_2 cap-and-trade program, are also very weak. As a result, EMA believes it is appropriate to treat the world oil market—and more specifically U.S. crude oil prices—as an exogenous input, as opposed to modeling it explicitly.

For months 1-12, the deflated New York Mercantile Exchange (NYMEX) Light Sweet Crude Oil (WTI, Symbol CL) futures prices are used. For months 13-48, we use a blend of the NYMEX futures in real money terms and the long-term forecast. Starting with the 49th month onwards we use the long-term forecast. We generate forecasts of region-specific prices for refined oil products burned in power plants, e.g., diesel and residual, based on an analysis of historical relationships between these prices and the West Texas Intermediate price.

3.4 Market Electricity Prices

The Western Electricity Coordinating Council (WECC) covers nearly 1.8 million square miles extending from Canada to Mexico, including the Canadian provinces of Alberta and British Columbia; Northern Baja California, Mexico; and all or portions of 14 Western states. EMA has further divided the WECC into 22 market areas as illustrated in Figure 5. These 22 market areas are within the six NERC Assessment Areas. Although WECC is predominantly a summer peaking region, Alberta, British Columbia, and Northwest loads peak in the winter.

The WECC is highly interconnected, and, with some limitation, generation from any area within WECC can be used to meet load in any other area. The diversity in loads, along with seasonal power exchanges between the hydro-rich Northwest and solar from the southwest and California, results in electricity markets and wholesale electric prices that are highly interdependent.

EMA created a forward view of the Colorado West regional electricity market. EMA is forecasting the actual day-ahead cash price that will occur in spot markets under normal conditions in the future, not the traded price of futures or forward contracts.

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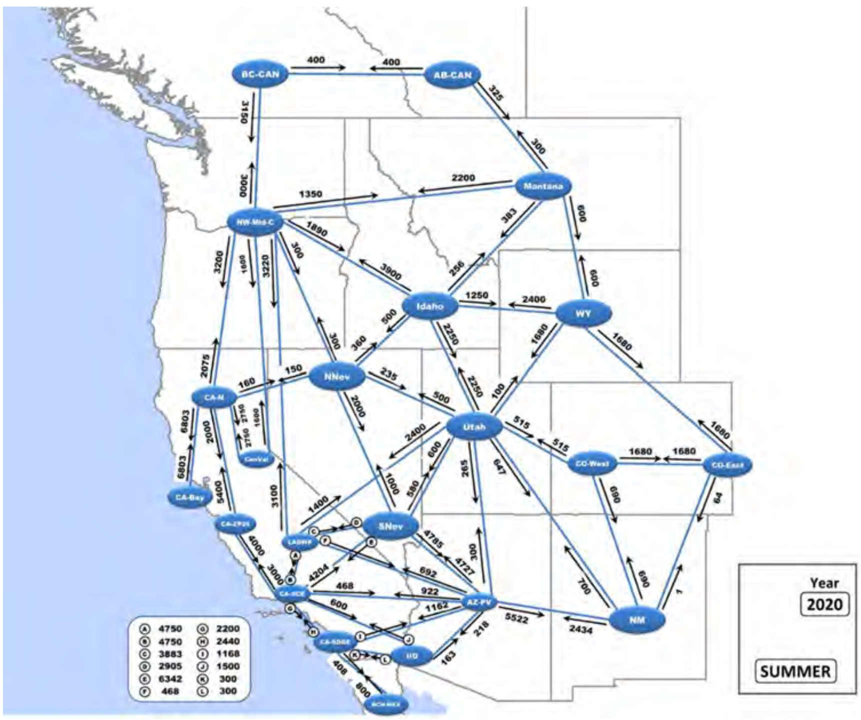
BHP's and CLF&P's models allow for the purchase of hourly economy energy from energy markets and monthly seasonal firm market purchases to cover short-term capacity shortfalls up to 50 MW. For economy energy purchase pricing, both BHP and CLF&P used the CO-West market area MCP forecast. The pricing for SFMP was derived by increasing the AZ-PV market area MCP forecast by 20 percent to emulate the additional cost of providing firm energy.

Figure 5 WECC Market Configuration



(Source: Energy Market Advisors)

Table 3 summarizes the Base annual 6x16 (On-Peak), Wrap (Off-Peak) and 7x24 (Average) electricity prices for the Colorado West region[3].

[3] The published EMA electric price forecasts were converted to nominal dollars using a 1.5% escalation rate.

HITACHI ABB

Table 3 Base Prices for the CO-West Market Area

	CO-West On-Peak	CO-West Off-Peak	CO-West Average
2021	38.18	23.26	31.79
2022	36.89	22.35	30.67
2023	38.74	24.23	32.50
2024	37.38	24.99	32.08
2025	34.98	26.21	31.22
2026	35.95	28.22	32.64
2027	35.91	30.32	33.51
2028	36.68	30.90	34.19
2029	37.07	31.84	34.83
2030	37.51	31.96	35.13
2031	47.60	38.21	43.58
2032	48.14	38.80	44.14
2033	49.55	39.99	45.45
2034	50.80	40.81	46.50
2035	51.80	42.14	47.66
2036	53.56	43.29	49.16
2037	56.53	46.95	52.42
2038	58.38	49.57	54.61
2039	59.36	51.26	55.89
2040	61.17	52.80	57.57

(Source: Energy Market Advisors)

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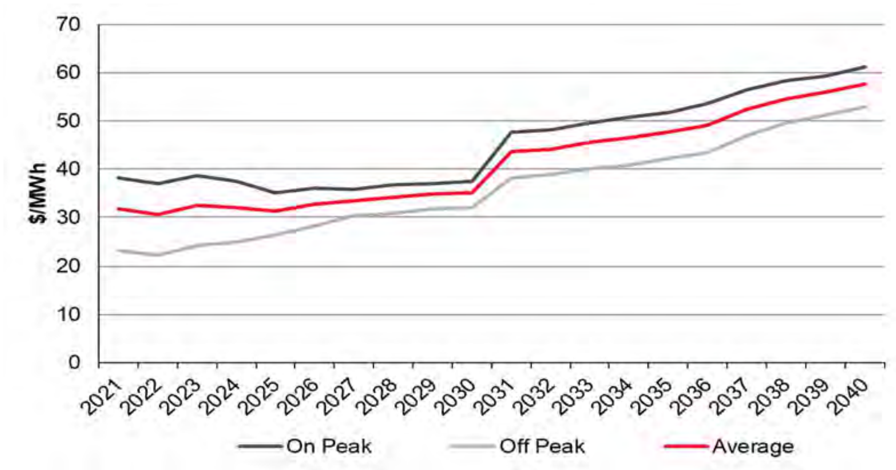
The CO-West market area Base electricity prices for on-peak, off-peak and average are shown in Figure 6.

Figure 6 Reference Case – CO-West Electricity Prices

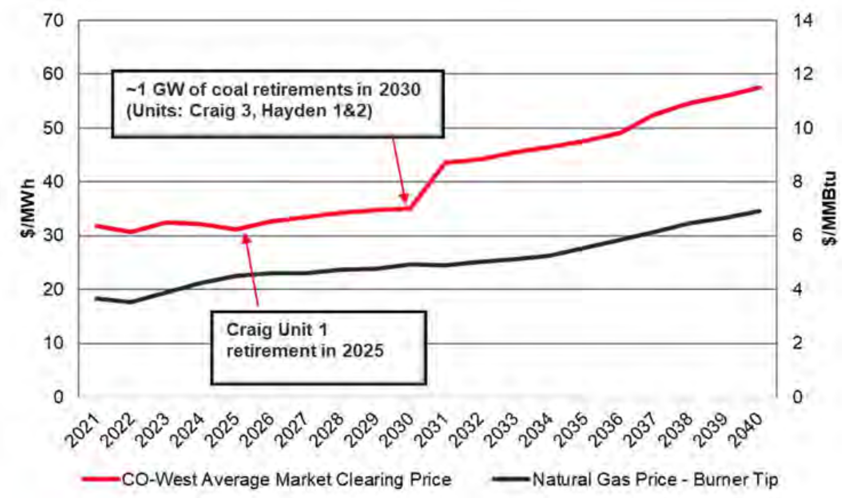


(Source: Energy Market Advisors)

Figure 7 shows that CO-West average prices increase starting in 2025 with the retirement of Craig Unit 1. From 2025 to 2030 prices trend upward in a similar manner as the natural gas price forecast. The sharp increase in the 2031 forecast is a result of the expected retirement of nearly one GW of coal generation. Craig 3 and Hayden units 1 & 2 are expected to retire in 2030.

The correlation between natural gas prices and MCP's is also depicted in Figure 7. In 2034, the natural gas price upward trend increases as a result of the year-over-year lack of growth in the total potential gas supply. Gas supply roughly flattens out from 2034-2040 as the potential supply from shale plays, especially tight liquids/shale oil plays, declines (Permian, Midcontinent, and Western Canada). At the same time gas demand continues to slowly increase during this timeframe, pushing the marginal resource up the supply curve more quickly than pre-2034.

Figure 7 Average CO-West Market Clearing Prices and NG-Colorado burner-tip gas prices



(Source: Energy Market Advisors)

3.5 High Gas Price and Low Gas Price Scenarios

The Fall 2020 Power Reference Case also includes forecasts for three additional scenarios: a Low Gas Price Scenario, High Gas Price Scenario, and Carbon Tax Scenario (CO_2 Tax). For the Fall 2020 Reference Case, EMA utilized a new approach in the development of gas price scenarios by using custom assumptions for supply fundamentals. This methodology isolates the impact of supply expectations on gas prices by holding other natural gas and power assumptions constant. The assumptions reflected in the gas scenarios are highlighted below:

- **Low Gas Price scenario** – Production costs are set equal to short-run marginal costs over the study period in this scenario. This scenario is intended to reflect pricing that could be sustained over the short-term. Over the long-term, significant technological improvements would be required to sustain the price trajectory in this scenario.

- **High Gas Price scenario** – Assumed long-run marginal production costs for shale plays are increased to at least the 75th percentile in this scenario. EMA reduced the overall availability of gas resources by approximately eight percent and defined higher costs for each shale play to create a geographically diversified gas price scenario.

The Fall 2020 Reference Case scenario natural gas price forecasts, MCP price forecasts and CO_2 tax forecast were used in the scenarios completed for CLF&P, BHP and the Joint System.

Figure 8 depicts the Henry Hub monthly price forecasts for the 2020 Fall Reference Case Base Case and two gas price scenarios, Low Gas Price and High Gas Price. The scenario prices directly reflect custom assumptions for supply fundamentals and how these would impact the utilization of storage, transmission, and ultimately prices at gas hubs throughout North America. Both cases hold all other assumptions for natural gas and power sector fundamentals constant to isolate the substantial impact of supply expectations on natural gas prices.

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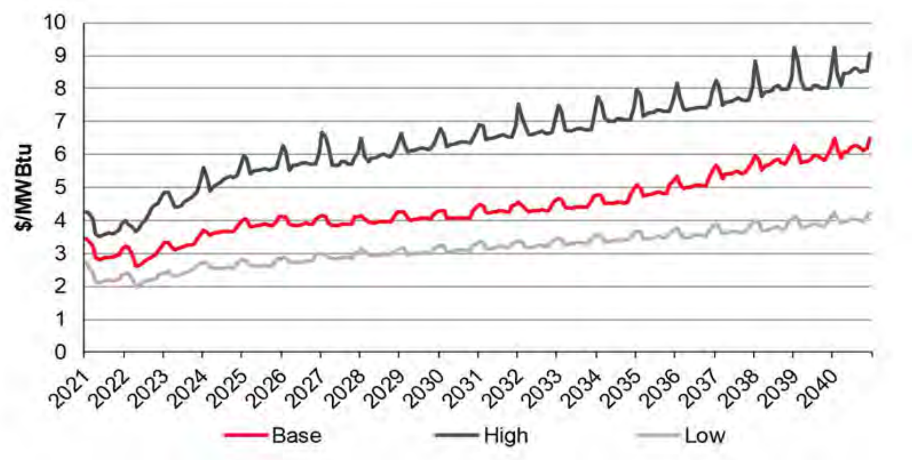
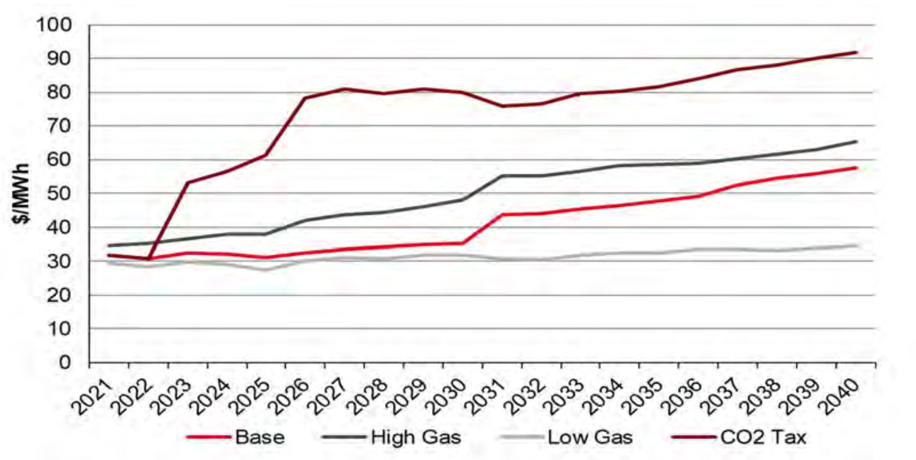
Figure 8 Monthly Henry Hub Natural Gas Prices



(Source: Energy Market Advisors)

Average CO-West electricity prices are shown in Figure 9 for the Fall 2020 Reference Case Base Case and three scenarios.

Figure 9 Average CO-West Base and Scenario Market Clearing Prices

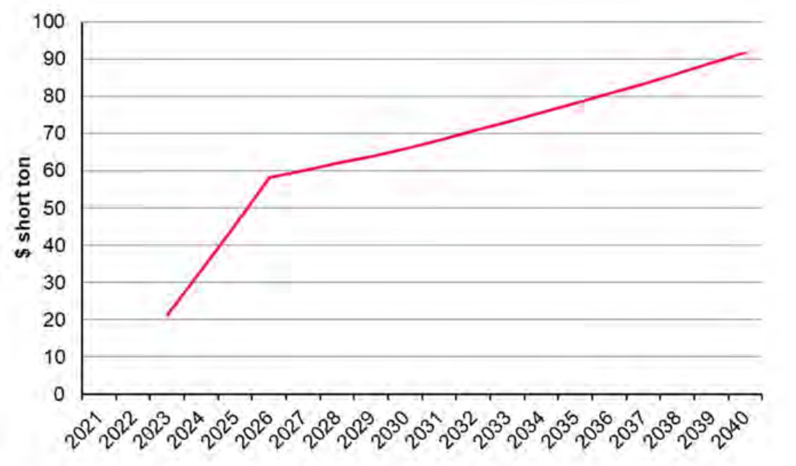


(Source: Energy Market Advisors)

3.6 Carbon Tax Scenario

EMA's CO_2 Tax Scenario is based on the U.S. Government's Social Cost of Carbon (August 2016 update) with a 3 percent discount rate. The carbon tax begins in 2023 and ramps up to the full Social Cost of Carbon in 2026. It is applied across North America and replaces all state or provincial carbon pricing programs. Figure 10 shows the Carbon Tax Scenario CO_2 emission cost annual forecast.

Figure 10 Carbon Tax Scenario CO_2 Emission Cost



(Source: Energy Market Advisors)

3.7 Regulating Reserves

EMA completed an assessment of Black Hills Power's Regulating Reserves, Flexible Capacity Requirement and Effective Load Carrying Capability as part of the Black Hills Power's Variable Energy Resource Integration Study. The study examined renewable and energy storage resource options of varying sizes and locations to assess incremental impacts of the addition of renewable resources on BHP's regulation requirements and costs. The assessment evaluated twelve different renewable and energy storage resource expansion options and five different potential geographic locations for those resources. These resource options and locations were specified by the BHP planning team, based on commercial interest it has seen in developing resources at those locations, and with a goal of capturing impacts of geographic diversity in wind and solar generation profiles within its service territories.

As part of the Variable Energy Resource Integration Study, estimated costs for BHP to carry additional Regulation Up and Regulation Down capacity were calculated. As shown in Table 4 these cost estimates reflect changes in BHP operating cost as the system unit commitment and dispatch is altered to reflect an increased Regulation Up and Down capacity operating reserve requirement. The costs did not reflect any capital related cost needed to procure additional flexible regulation capacity. EMA estimated incremental regulation costs assuming Regulation Up and Down quantities needed to meet the 98 percentile North American Reliability Council (NERC) Control Performance Standard 2 (CPS2). For resource portfolios that include only battery storage projects, EMA did not estimated an incremental regulation requirement or cost, as storage only resources are unlikely to cause incremental ACE deviations.

BHP also has an option to procure regulation from WAPA, through its Open Access Transmission Tariff (OATT) at a lower cost. WAPA's current tariff offers regulation service for a fixed cost of \$0.303/kW/Month for wind resources, and \$0.205/kW/Month for solar resources. At a 40% annual average wind capacity factor, the WAPA regulation cost is equivalent to \$1.04/MWh for

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wind resources, and at a 25% annual average capacity factor for solar, the regulation cost would be equivalent to $1.12/MWh for solar resources. The WAPA tariff rates were used in all three of the resource plan's modelling. Table 4 provides a summary of the renewable and energy storage resource options and projected regulation requirements included in the Variable Energy Resources Study.

Table 4. Incremental BHP Regulating Reserve Cost

Portfolio	Type	Size (MW)	Location	98% CPS2: Incremental Regulation Up (MW)	98% CPS2: Incremental Regulation Down (MW)	Regulation Cost – BHP Generation ($/MWh)	Regulation Cost – WAPA Tariff ($/kW/Mo)
Existing System				55	50		
1	Wind	50	Cheyenne	24	0	$10.17	$0.303
2	Wind	100	S. Gillette	26	22	$6.56	$0.303
3	Wind	200	N. Douglas	50	40	$11.12	$0.303
4	Solar	50	Cheyenne	7	1	$5.38	$0.205
5	Solar	100	Gillette	10	1	$4.63	$0.205
6	Solar	200	Hot Springs	11	1	$1.57	$0.205
7	Solar + Storage	100 + 40	Cheyenne	0	1	$0.02	$0.205
8	Solar + Storage	100 + 20	Gillette	0	1	$0.03	$0.205
9	Solar + Storage	100 + 60	Hot Springs	0	1	$0.02	$0.205
10	Storage	20	Cheyenne	0	1	N/A	
11	Storage	40	Gillette	0	1	N/A	
12	Storage	60	Hot Springs	0	1	N/A	

3.8 Flexible Capacity Requirement

In addition to assessing incremental regulation requirements and costs likely to be incurred due to changes in BHP operating costs, EMA also completed an assessment of whether BHP, CLF&P or the Joint System was likely to require additional flexible capacity to integrate the renewable resources identified in the resource portfolios created for each scenario. EMA used a methodology originally developed by the California Independent System Operator (CAISO) to assess each portfolio system's flexible capacity requirements. The final assessment showed that each system's existing flexible capacity was sufficient when the variable energy resources added in each portfolio were added to their system, with the exception of a few scenarios as shown in Table 5. This was accomplished by modelling multiple capacity expansion iterations. If the existing flexible capacity was not sufficient for a portfolio, the cost of flexible peaking capacity was added to the portfolio options and a new expansion plan was developed. The cost for a LM6000 combustion turbine, on a $/kW-Yr basis, and any flexible capacity requirements identified for each resource plan were reflected in the expansion plan resource options.

Table 5. Flexible Capacity Requirements

System	Scenario	MW Requirement	Starting in Year
BHP	B2 & B9	41 MW	2025
	B7	38 MW	2024
CLF&P	C1	9 MW	2033
	C8	9 MW	2033
	C2 & C10	29 MW	2029
	C4	9 MW	2033
	C6	9 MW	2033
	C7	9 MW => 57 MW	2026 => 2032
	C9	29 MW	2033
Joint	J2	49 MW	2023
	J4	30 MW	2033
	J6	49 MW	2034

3.9 Effective Load Carrying Capability

EMA also completed an Effective Load Carrying Capability (ELCC) assessment of the wind, solar and battery storage resource portfolio options as part of the Black Hills Power Variable Energy Resource Integration Study. This study was used to assess the level of reserve capacity that each option provides to BHP and the data was also used for their resource portfolio options. The ELCC analysis was used to determine the percentage of the nameplate capacity of each resource type and location that can be counted on for reserve margin planning purposes.

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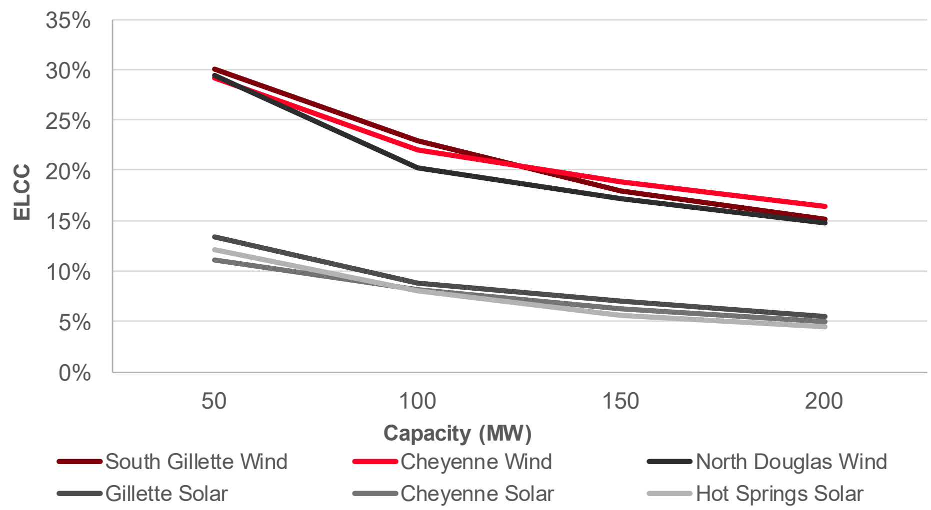
Figure 11. ELCC Capacity of Wind and Solar Resources



As shown in Figure 11, the ELCC values for wind are comparable at all three locations for 50 MW resource additions. For 100 MW wind resource additions, ELCC values are highest at South Gillette, followed by Cheyenne and then North Douglas. Projected ELCC values at South Gillette begin at 30 percent with a 50 MW wind addition and decline with additional wind expansion. The ELCC values for wind at Cheyenne and Douglas begin in the 28 percent range and decline with additional wind expansion. However, for the Cheyenne site, estimated ELCC values see a lesser decline than the other two sites, for wind additions of 150 and 200 MW.

For solar resources, ELCC values are highest at the Gillette location, followed by Hot Springs and then Cheyenne. Solar ELCC values are considerably lower than those for wind resources, ranging in the 11 to 13 percent range with 50 MW additions, and declining to around 5 percent with 200 MW solar additions. The primary driver for lower solar ELCC values is a lower capacity factor for solar resources, compared to wind.

EMA also calculated the ELCC value of stand-alone battery storage at four capacity levels, 20 MW, 40 MW, 60 MW and 100 MW. The battery charge level was determined in every hour to calculate the amount of capacity that a stand-alone battery storage facility can provide. This capacity ranges between 0 MW and the maximum capacity of the storage facility. Table 6 lists the estimated ELCC values. As the size of the capacity increases from 20 MW to 60 MW, the effective capacity contribution is expected to decrease from 80% to 54%.

Table 6. ELCC of Battery Storage

Type	Capacity (MW)	Incremental Demand (MW)	ELCC (%)
Storage	20	16	80%
Storage	40	27	67%
Storage	60	33	54%
Storage	100	49	49%

3.10 Future Generation Options

As mentioned previously, BHC provided data necessary to model a variety of proposed units including natural gas-fired thermal generation, renewable generation, energy storage and existing generation betterment options. The data BHC supplied included unit characteristics, operating costs and financial criteria for five natural gas-fired thermal options, a biofuel option, six renewable options (wind and solar, four Battery Energy Storage System (BESS) options and three solar paired with BESS options. Betterment options included conversion to natural gas or life extension of the coal-fired Neil Simpson II unit, conversion of the Ben French Diesel units to natural gas and expansion of the CPGS LM6000 to a combined cycle unit.

Battery storage can be modeled in PO purely as an arbitrage opportunity or can be paired with another generating unit that exclusively charges the battery. In both cases the battery attempts to charge during the lowest-priced hours in a day and discharge during the highest-priced hours. In this way batteries can provide peak shaving benefits, as it will generally be the case that the highest-priced hours coincide with the system peak and when the battery is economically incentivized to discharge. The battery options modeled as part of this IRP used an algorithm that estimates marginal costs to determine economic charging and generating schedules. Battery storage options for the BHP and CLFP IRPs were modelled in two ways; as standalone (charged by the system) and paired with proposed solar facilities. In both cases, the BESS stations were not limited to a specific number of cycles per day, maximum energy per charge or daily maximum generation.

3.11 Financial Parameters

Financial assumptions used in the modelling are included in Table 7. In addition, a 21% federal income tax rate was used. Book life and tax life assumptions for various technologies were provided by BHC. They included 35 years for combined cycle and peaking technologies, 25 years for wind and solar, and 20 years for battery storage. Tax lives of 20 years were used for combined cycle, 15 years for peaking technology, 7 years for battery storage and 5-year life for solar and wind. Unless otherwise specified, a 1.5% escalation rate was assumed.

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Table 7. Financial Assumptions

	CLF&P	BHP	Joint System
Discount Rate	6.3	6.13	6.2
Debt (%)	46	47	47
Equity (%)	54	53	53
Cost of Debt (%)	5.72	Global Settlement	5.94
Cost of Equity (%)	9.9	Global Settlement	9.5
Property Tax Rate (%)	.43	.6	.53

4 Stochastic Analysis

In order to simulate the risk associated with uncertainties in electric prices, fuel prices and load forecasts stochastic analysis was undertaken. The stochastic process involves completing a specified number of independent simulations or “runs”, with each run representing a "draw" or iteration that contain variations in the values of the selected uncertainties. The Stochastic Analysis component within PO was used to complete the stochastic analysis. This component includes a Regression Tool that computes stochastic properties for variables and a Draw Generation Tool that generates sample random draws using the distributions calculated by the Regression Tool.

PO’s built-in Regression Tool uses user-specified historical data and distribution types and sample settings to calculate the stochastic properties of variables. Stochastic properties that are computed include, among others, volatility, short-term mean-reversion rate, standard deviation and correlations among the random time-series. PO’s Draw Generation Task generates sample random draws using the distributions calculated by the Regression Tool. The power simulation model uses these random paths to optimize commitment and dispatch along each random path.

The PO stochastic modelling framework allows the user to specify, for each stochastic entity, a specific distribution type. The options include:

- Continuous – Time
  - Normal and LogNormal Mean-reverting Distributions
- Discrete Time Independent
  - Normal, LogNormal, Uniform and Triangle Distributions

The stochastic distribution typically assumed for price variables such as fuel prices, emission costs or electricity prices is either a Normal or LogNormal Mean-Reverting Distribution. The Mean-Reverting distribution’s short-term process features shocks, whose effect through time evaporates as the variable returns to its expected value. While the long-term process shocks expected value with no reversion to mean. The lognormal distribution, particularly in comparison to the normal distribution, is widely used as the stochastic model distribution for prices because it is restricted to positive values. There is an expectation that fuel and energy commodities will always have value and therefore draws for price variables should not include non-positive values. Zero or negative prices cannot be produced by a lognormal distribution.

Load variables are typically characterized by ether a Normal, LogNormal, Uniform or Triangle Distribution. These types of distributions generate draw values for a particular time period and are not directly dependent on the previous period’s draw value. These types of distributions are used when modeling uncertainties in escalation and inflation rates and monthly peak and energy for load.

4.1 Stochastic Variables

Based on results from the Capacity Expansion and PO simulations, CLF&P and BHP selected seven scenarios for stochastic evaluation: Scenarios 1, 2, 3, 4, 5, 6 and 8. Stochastic runs were performed for 50 iterations where each utility’s load, the Colorado-West Market Price forecast, coal price forecast and the appropriate natural gas price forecast[4] were all varied stochastically.

[4] Stochastic variables for the three natural gas price forecasts, NG_Cheyenne, NG_Gillette, and NG_Rapid City are based on historical Henry Hub price data.

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As discussed above, the model calculated short term volatilities and mean reversion rates shown in Table 8 for the natural gas and coal stochastic variables. Standard deviation and time correlations for the BHP and CLF&P load stochastic values are shown in Table 9. In addition, correlations between the natural gas and electric market price variables were calculated and are shown in Table 10. Load was modelled with a normal distribution while the market prices and natural gas prices were modeled with a lognormal distribution based on the reasoning mentioned earlier.

Table 8 Short Term Volatilities and Mean Reversion Rates

	Short Term Volatility Rate	ST Mean Reversion Rate
Gillette Coal	0.084	0.345
EP_COW	0.199	0.291
NG_Cheyenne	0.112	0.102
NG_Rapid City	0..112	0.102
NG_Gillette	0.112	0.102

(Source: Energy Market Advisors)

Table 9 Standard Deviation and Time Correlations

	Standard Deviation	Time Correlation
CLF&P Load		
June - Sept	12.637	0.945
Oct - May	14.456	0.945
BHP Load		
June - Sept	9.721	0.663
Oct - May	10.921	0.663

(Source: Energy Market Advisors)

Table 10 Commodity Correlations

	NG_Cheyenne	NG_Gillette	NG_Rapid City	EP_COW
EP_COW	0.40	0.40	0.40	1.0

(Source: Energy Market Advisors)

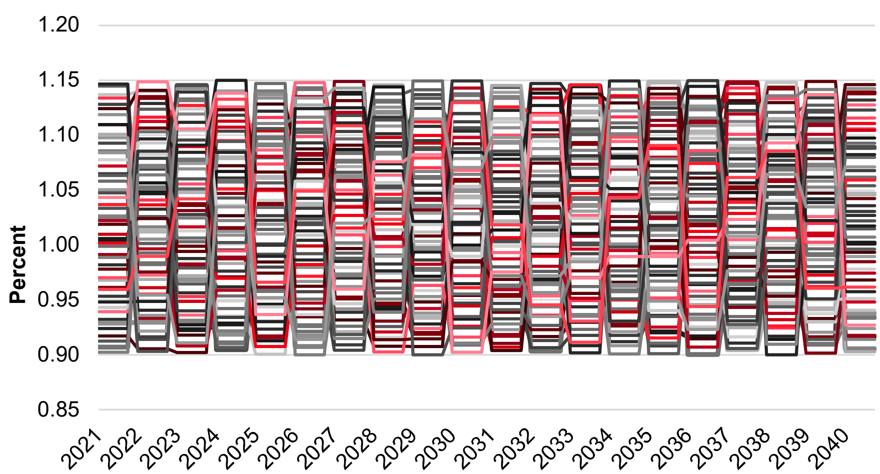
4.2 Capital Cost

Using Strategic Planning's Stratified Monte Carlo sampling program, EMA created 50 future scenarios for portfolio evaluation. EMA has performed extensive market price trajectory simulations and has determined that 50 trajectories provide a reasonable balance between the number of scenarios to provide a convergent solution balanced with a manageable number of stochastic scenarios to be applied to many resource plan alternatives. Uncertainty draws were made for the capital cost of the resource additions in the portfolio evaluation. These capital cost draws are combined with the uncertainty draws generated by PO.

4.2.1 Long-Term Capital Cost Uncertainty

Capital cost is a constant variance variable with a uniform distribution. Capital cost ranges were based on forecasts from Lazard, AEO20 and NREL-ATB with final input from BHC's Resource Planning Team. It was assumed that the multipliers for capital cost will range from .9 to 1.15 with an expected value of 1.025. Figure 12 shows the multipliers used for a Simple Cycle. Separate multipliers were used for wind, solar, combined cycles and storage, however graphically the draws remain similar.

Figure 12 Simple Cycle Capital Cost Multiplier



(Source: Energy Market Advisors)

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4.2.2 Summary of Uncertainty Variables

Table 11 is a summary of the uncertainty variables used in the stochastic analysis and their range of multipliers.

Table 11 Uncertainty Variable Range Multipliers

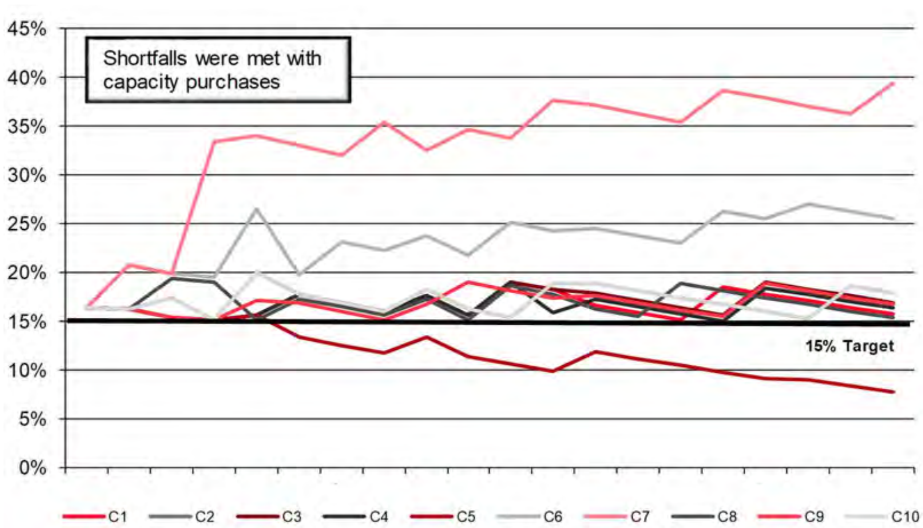
Uncertainty	Uncertainty Range
Simple Cycle Costs	0.9 – 1.15
Combined Cycle Costs	0.9 – 1.15
Wind	0.9 – 1.15
Solar	0.9 – 1.15
Storage	0.9 – 1.15
Load – CLF&P	0.39 – 1.53
Load - BHP	0.39 – 1.53
Market Price	1.12 – 2.05
Natural Gas Price	0.34 – 2.80
Coal Price	0.92 – 1.41

(Source: Energy Market Advisors)

4.3 Regulatory Capacity

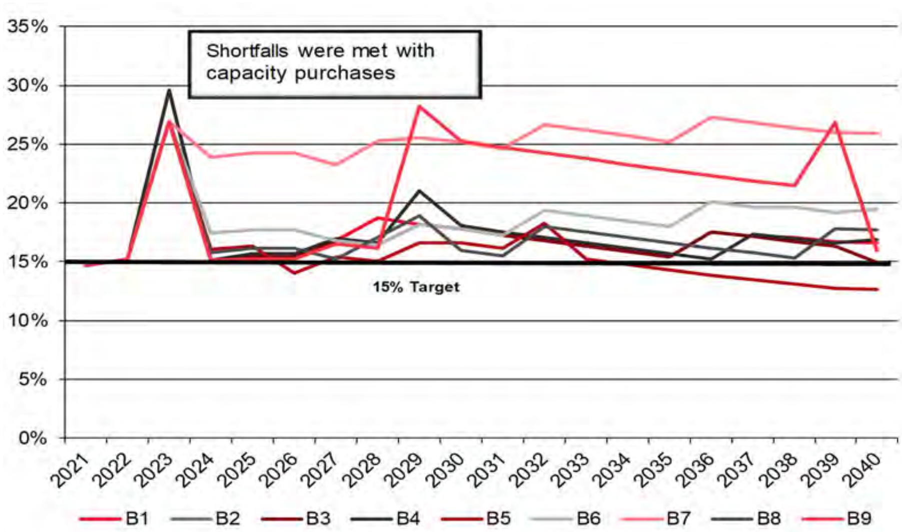
The deterministic simulations in PO were designed, under median assumptions, to maintain a minimum 15% reserve margin, with the exception of the low load scenario as shown in Figure 13, Figure 14 and Figure 15. To address any reserve margin deficits, EMA used the levelized cost of a new LM6000 combustion turbine as a proxy for purchases from a capacity market to meet the reserve margin target.

Figure 13 CLF&P All Scenarios – Capacity Margin



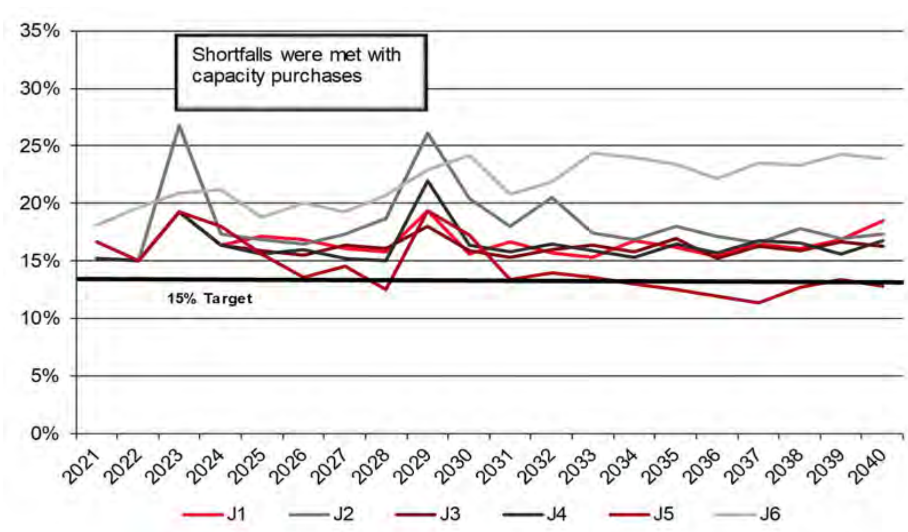
(Source: Energy Market Advisors)

Figure 14 BHP All Scenarios – Capacity Margin



(Source: Energy Market Advisors)

Figure 15 Joint System All Scenarios – Capacity Margin



(Source: Energy Market Advisors)

When exposed to demand uncertainty in the stochastic process, there are certain scenarios where the resource plan would become reserve margin deficit. Again, to address these deficits, EMA used the levelized cost of a new LM6000 combustion turbine as a proxy for purchases from a capacity market to meet the target. Figure 16 illustrates the annual reserve margins for the fifty load draws.

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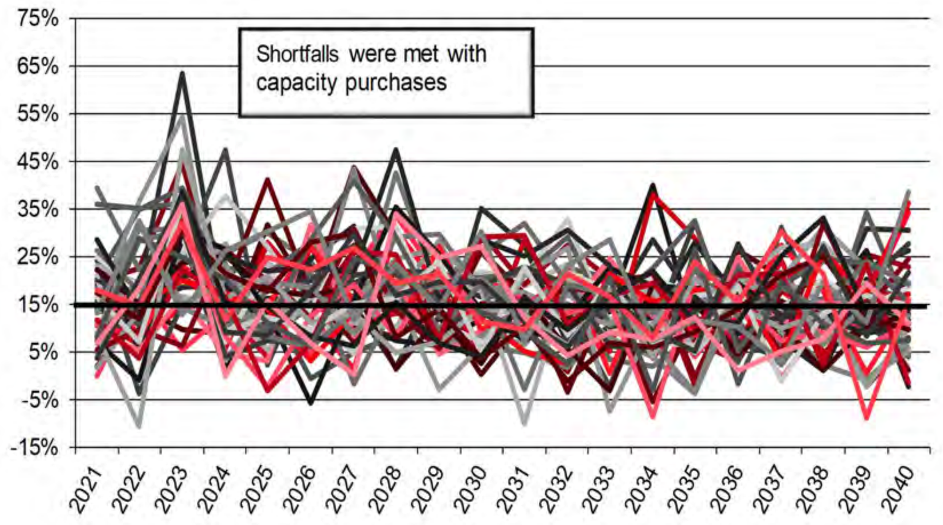
Figure 16 Portfolio B1 Reserve Margins for Fifty Load Draws



(Source: Energy Market Advisors)

5 Capacity Expansion Results

To produce optimal resource plans under a variety of conditions BHC identified nine scenarios for CLF&P, eight scenarios for BHP and six scenarios for the joint system to optimize in the Capacity Expansion module. Table 12, Table 13 and Table 14 summarize the optimal resource expansion plans for each utility as well as the Joint System for each of their scenarios (the table does not include seasonal firm market purchases). Seasonal firm market purchases are short term purchases that do not have capital costs. The cost of SFMPs are included in the income statements as purchase power. As noted in the Executive Summary Portfolio Description Table, C10 and B9 use the same portfolio as C2 and B2 respectively.

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Table 12 CLF&P Optimal Expansion Plans

YEAR	C1	C2	C3	C4	C5	C6	C7	C8	C9	C1
2021										
2022										
2023		Wind 50 MW						Storage 10 MW		Wir 50 M
2024		Solar 50 MW					Wind 50 MW			Sola 50 M
2025									Solar 50 MW Wygen 2 Carbon Capture	
2026						Wind 50 MW	Storage 10 MW Wind 50 MW		Wind 50 MW	
2027										
2028										
2029		Wind 50 MW								Wir 50 M
2030										
2031										
2032				Wind 50 MW			Wind 50 MW			
2033	LM6000 42 MW Wind 100 MW	LM6000 42 MW	LMS100 91 MW	LM6000 42 MW Wind 100 MW	LM6000 42 MW Wind 50 MW	LMS100 91 MW Wind 50 MW	LMS100 91 MW	LM6000 42 MW Wind 100 MW	LMS100 91 MW Wind 50 MW	LM60 42 M
2034										
2035										
2036										
2037										
2038					Wind 50 MW	Solar 50 MW				
2039							Wind 50 MW			
2040										

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Table 13 BHP Optimal Expansion Plans

YEAR	B1	B2	B3	B4	B5	B6	B7	B8	B9
2021									
2022									
2023	Wind 50 MW	Wind 250 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	Storage 10 MW Solar 50 MW	Wind 250 MW
2024	Wind 50 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	Solar 50 MW	Wind 50 MW	Wind 150 MW Solar 50 MW	Wind 50 MW	Wind 50 MW
2025	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW Solar 100 MW	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW Solar 100 MW	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW Solar 100 MW
2026									
2027									
2028									
2029									
2030					Wind 50 MW				
2031									
2032								Wind 50 MW	
2033									
2034									
2035									
2036									
2037									
2038	Wind 50 MW					Wind 50 MW			
2039		Wind 100 MW						Wind 50 MW	Wind 100 MW
2040	Wind 100 MW		Wind 150 MW	Wind 150 MW	Wind 100 MW	Wind 150 MW	Wind 150 MW Storage 10 MW	Wind 100 MW	

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Table 14 Joint System Optimal Expansion Plans

YEAR	J1	J2	J3	J4	J5	J6
2021						
2022						
2023		Wind 200 MW Solar 200 MW				
2024						
2025	NS2 Coal to Gas 79 MW Solar 200 MW	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW Solar 200 MW	NS2 Coal to Gas 79 MW Solar 200 MW	NS2 Coal to Gas 79 MW Solar 200 MW
2026				Wind 50 MW		
2027						
2028						
2029						
2030						
2031						Wind 50 MW
2032						Wind 50 MW
2033	Wind 100 MW			Wind 150 MW	Wind 100 MW	Wind 50 MW
2034	Wind 50 MW					Wind 50 MW
2035						
2036			Wind 50 MW			
2037					Wind 50 MW	
2038				Wind 50 MW		Wind 50 MW
2039						
2040	Wind 150 MW	Storage 10 MW	Wind 150 MW	Wind 100 MW	Wind 50 MW	Wind 150 MW

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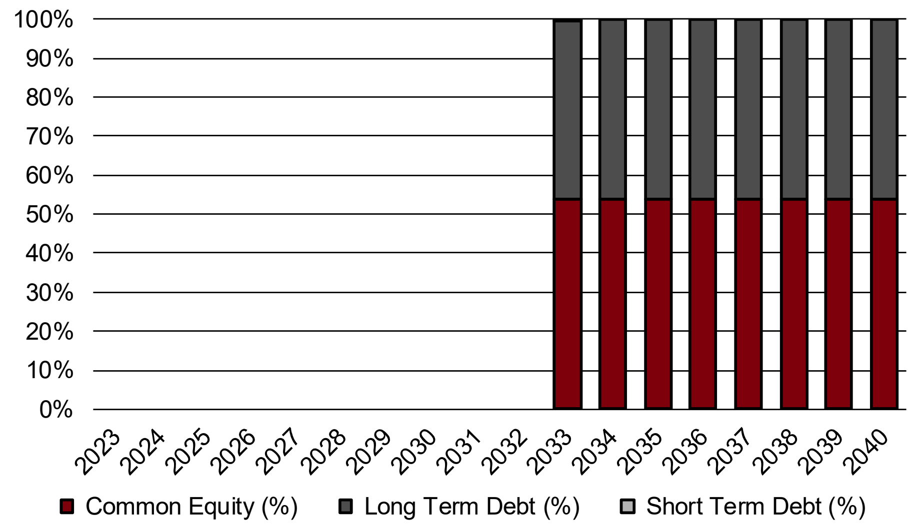
6 Deterministic Portfolio Results

6.1 Portfolio 1 Results

EMA evaluated multiple scenarios with varying inputs to highlight the effect of fuel price, market electricity price and load when determining future resource portfolios. This set of scenarios includes a plan that used price and load forecasts that are considered to most likely represent future prices (median). For CLF&P, portfolio C1 meets the needs of its forecast energy requirements under median assumptions. Figure 17 shows the capitalization ratios for C1. The financial modelling includes only incremental rate base additions with financing beginning in 2033 with the addition of a LM6000 and a 100 MW wind facility. Figure 18 shows the incremental annual rate increase for C1.

Figure 17 Portfolio C1 - Capitalization Ratios



(Source: Energy Market Advisors)

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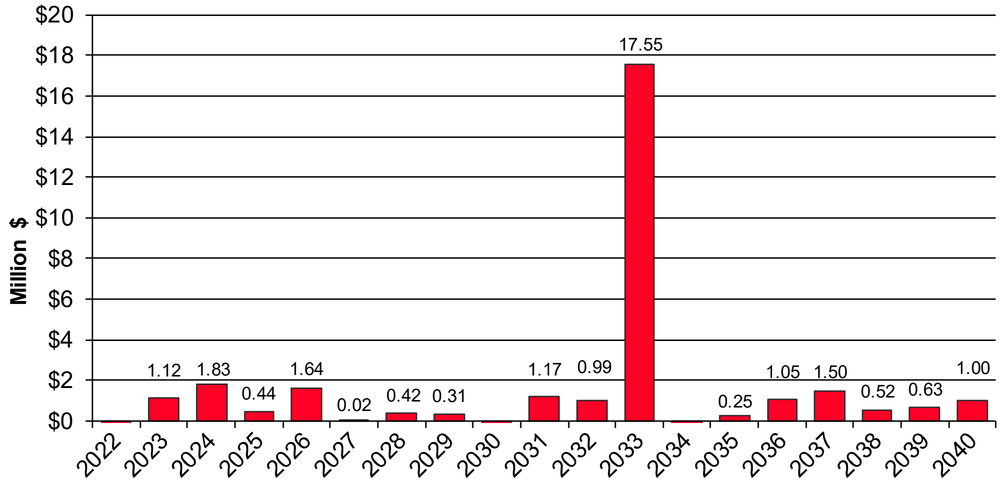
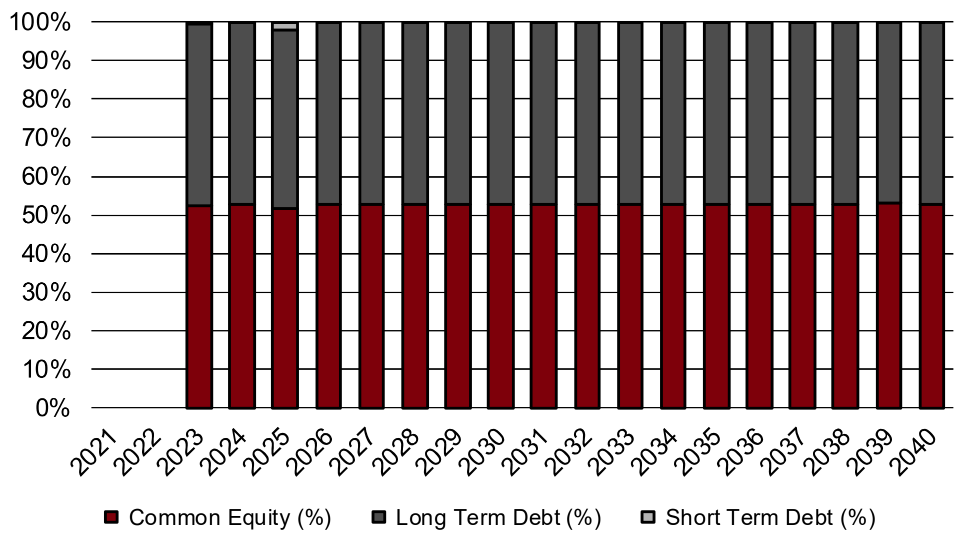
Figure 18 Portfolio C1 – Annual Rate Increases



(Source: Energy Market Advisors)

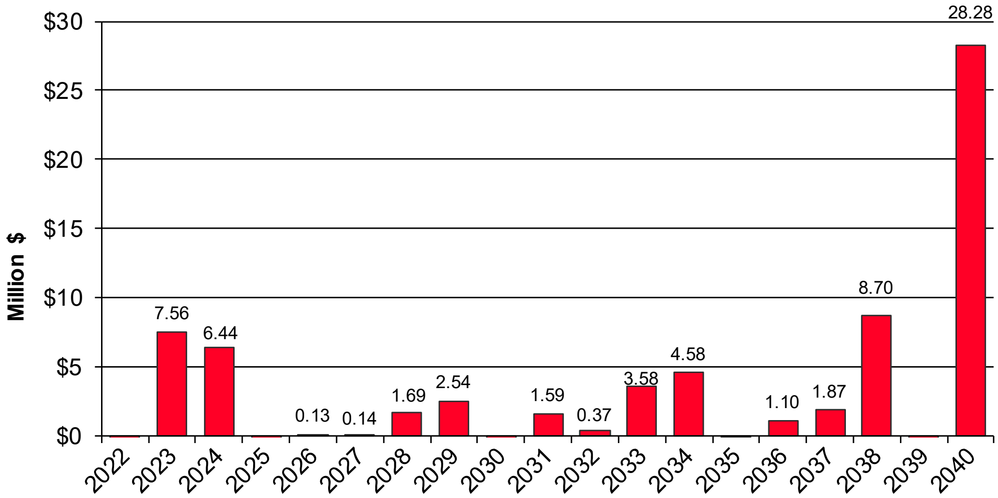
Portfolio B1 meets the needs of BHP's forecast energy requirements under median assumptions. Figure 19 shows the capitalization ratios for B1. The financial modelling includes only incremental rate base additions, with financing beginning in 2023 when a 50 MW Wind facility is added to BHP's system. Additional builds include a 50 MW Wind facility in 2024, NS2 Coal to Gas conversion in 2025, 50 MW Wind facility in 2038 and 100 MW Wind facility in 2040. Figure 20 shows the incremental annual rate increase for B1.

Figure 19 Portfolio B1 - Capitalization Ratios



(Source: Energy Market Advisors)

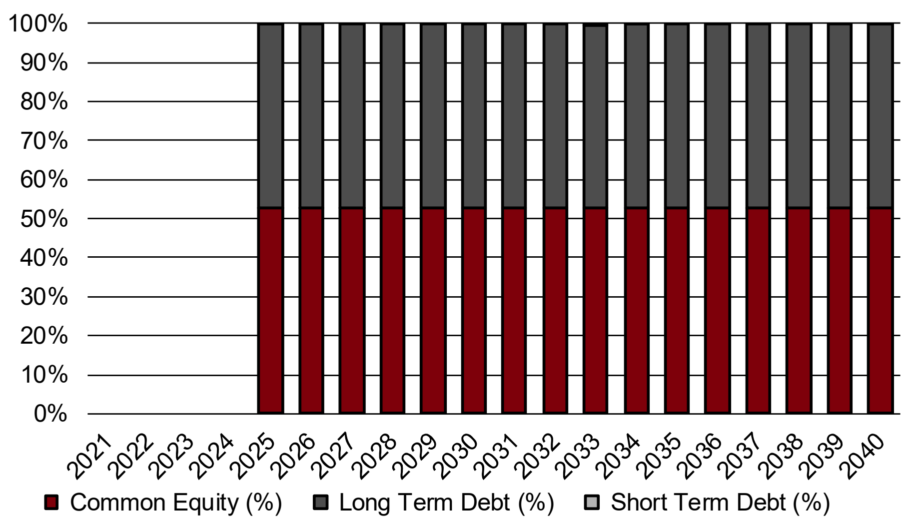
Figure 20 Portfolio B1 – Annual Rate Increases



(Source: Energy Market Advisors)

Portfolio J1 meets the needs of the Joint System's forecast energy requirements under median assumptions. Figure 21 shows the capitalization ratios for portfolio J1. The financial modelling includes only incremental rate base additions. Financing for the Joint System begins in 2025 with the NS2 Coal to Gas conversion and a 200 MW Solar facility. Additional builds include a 100 MW Wind facility in 2033, 50 MW Wind facility in 2034 and 150 MW Wind facility in 2040. Figure 22 shows the incremental annual rate increase for portfolio J1.

Figure 21 Portfolio J1 - Capitalization Ratios



(Source: Energy Market Advisors)

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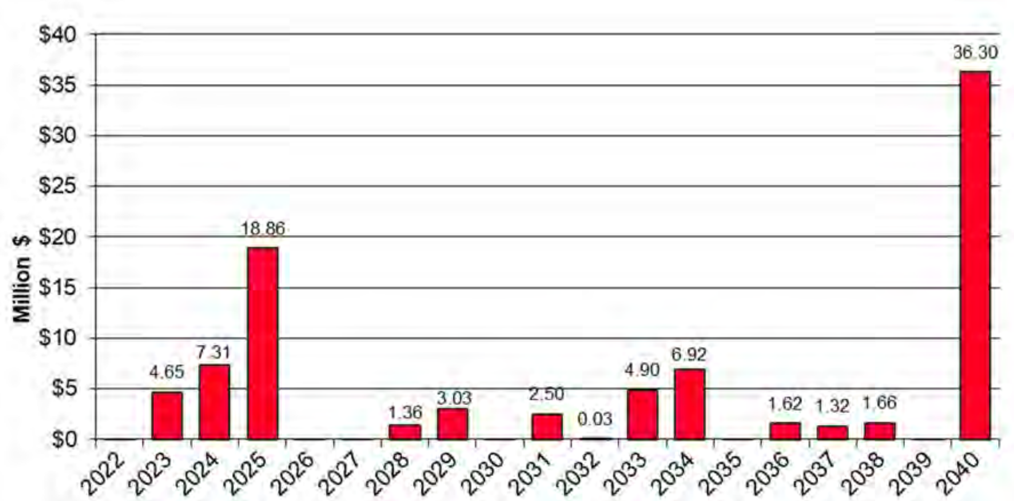
Figure 22 Portfolio J1 – Annual Rate Increases



(Source: Energy Market Advisors)

6.2 All Scenarios Results

The following series of tables and graphs compares the deterministic results for each IRP Portfolio over the twenty-year planning period (2021 through 2040). Table 15 and Figure 23 shows the PVRR for the ten CLF&P Portfolios.

Table 15 CLF&P Portfolios - 20 Year Deterministic PVRR (million $)

Scenario/ Portfolio	Load Growth	Electric Price	Gas Price	Carbon Cost Adder	Resource Selection	PVRR
C1	Median	Median	Median	None	Economic	$679.02
C2	Median	CO_2 Tax	Median	CO_2 Tax	Economic	$745.72
C3	Median	Low	Low	None	Economic	$665.54
C4	Median	High	High	None	Economic	$733.09
C5	Low	Median	Median	None	Economic	$670.01
C6	High	Median	Median	None	Economic	$720.83
C7	High + Step	Median	Median	None	Economic	$833.54
C8	Median	Median	Median	None	10 MW BESS	$693.36
C9	Median	Median	Median	None	Carbon Capture	$1,034.20
10	Median	Median	Median	ACP	Portfolio C2	$1,175.20

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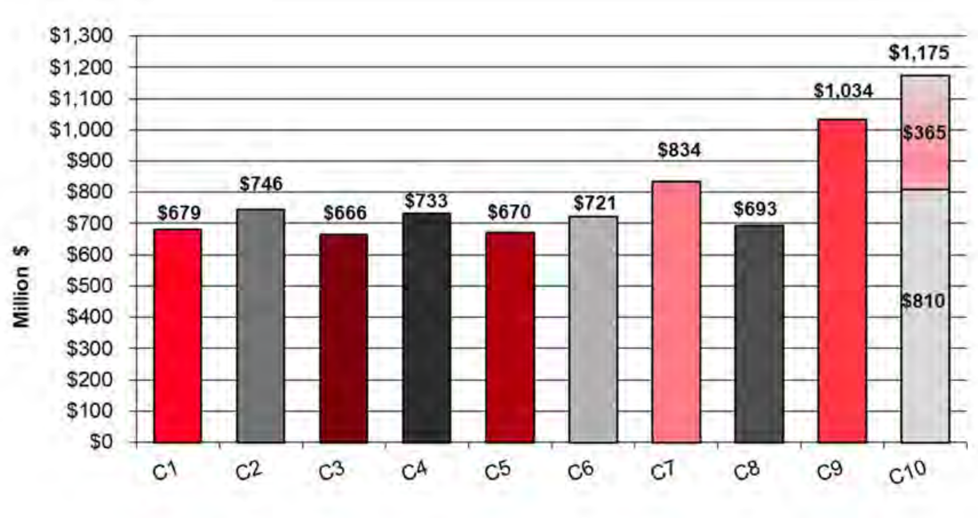
Figure 23 CLF&P Portfolios – Deterministic PVRR (2021-2040)



(Source: Energy Market Advisors)

BHP production costs modelling included nine portfolios. Table 16 and Figure 24 shows the deterministic PVRRs for the nine BHP Portfolios for the years 2021-2040.

Table 16 BHP Portfolios - 20 Year Deterministic PVRR (million $)

Scenario/ Portfolio	Load Growth	Electric Price	Gas Price	Carbon Cost Adder	Resource Selection	PVRR
B1	Median	Median	Median	None	Economic	$752.54
B2	Median	CO_2 Tax	Median	CO_2 Tax	Economic	$985.65
B3	Median	Low	Low	None	Economic	$748.69
B4	Median	High	High	None	Economic	$795.04
B5	Low	Median	Median	None	Economic	$777.24
B6	High	Median	Median	None	Economic	$757.23
B7	High + Step	Median	Median	None	Economic	$908.43
B8	Median	Median	Median	None	10 MW BESS	$795.60
B9	Median	Median	Median	ACP	Portfolio B2	$1,228.60

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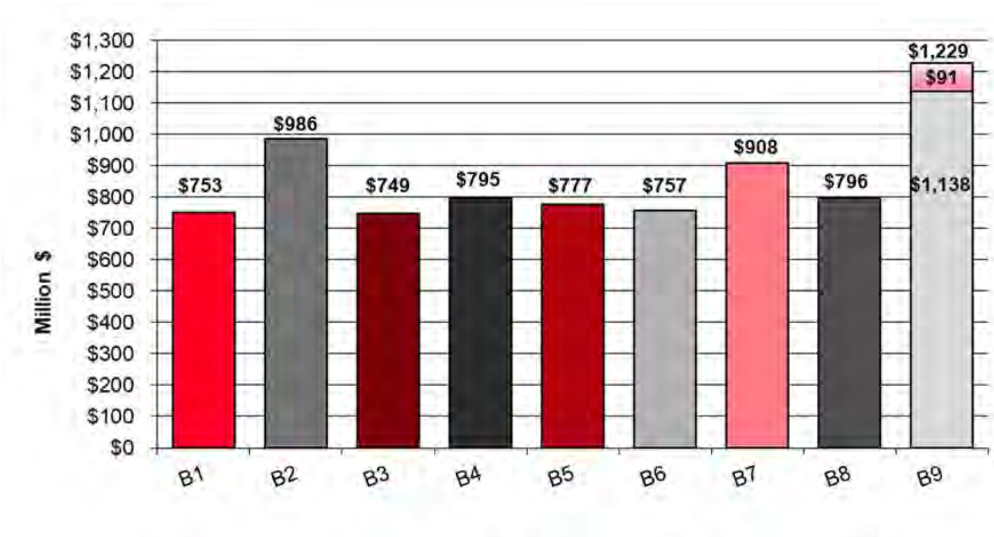
Figure 24 BHP Portfolios – Deterministic PVRR (2021-2040)



(Source: Energy Market Advisors)

Last, the Joint System production cost modelling included six portfolios. Table 17 and Figure 25 shows the PVRR for six Joint System portfolios for the years 2021-2040.

Table 17 Joint System Portfolios - 20 Year Deterministic PVRR (million $)

Scenario/ Portfolio	Load Growth	Electric Price	Gas Price	Carbon Cost Adder	Resource Selection	PVRR
J1	Median	Median	Median	None	Economic	$1,398.97
J2	Median	CO_2 Tax	Median	CO_2 Tax	Economic	$1,556.60
J3	Median	Low	Low	None	Economic	$1,307.51
J4	Median	High	High	None	Economic	$1,454.92
J5	Low	Median	Median	None	Economic	$1,398.81
J6	High	Median	Median	None	Economic	$1,459.74

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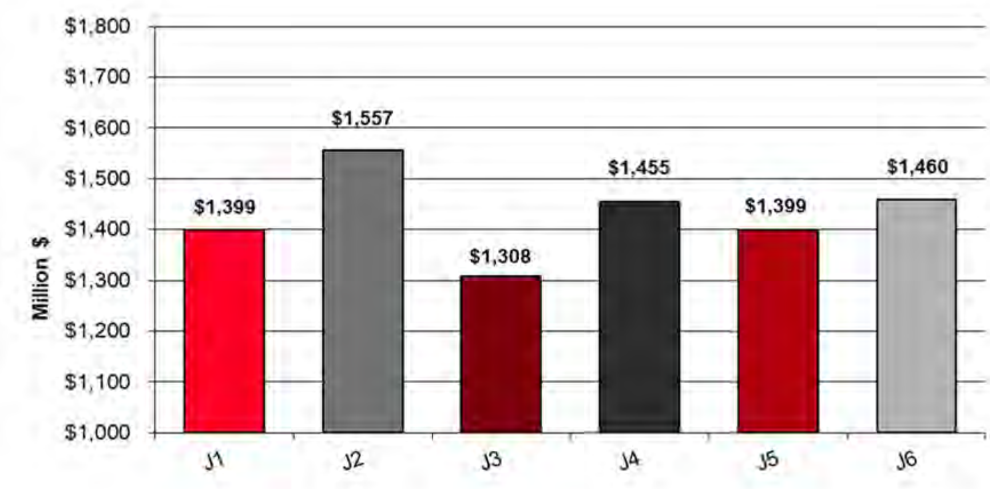
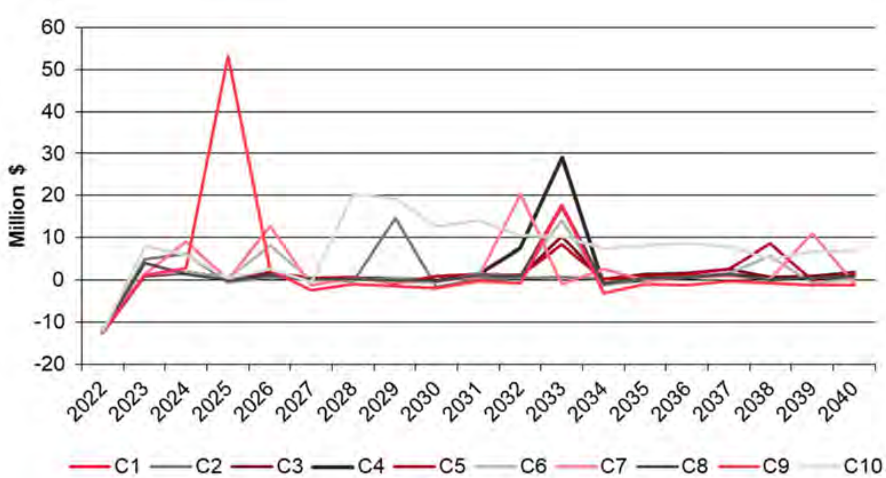
Figure 25 Joint System Portfolios – Deterministic PVRR (2021-2040)



(Source: Energy Market Advisors)

The following series of graphs compares the Incremental Annual Rate Increases for BHP's, CLF&P's and the Joint System's portfolios.

Figure 26 CLF&P All Scenarios – Incremental Annual Rate Increases



(Source: Energy Market Advisors)

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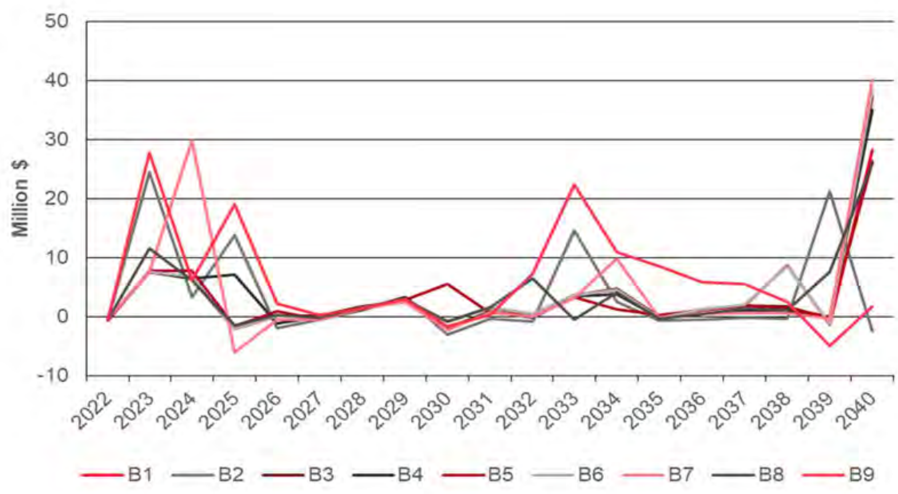
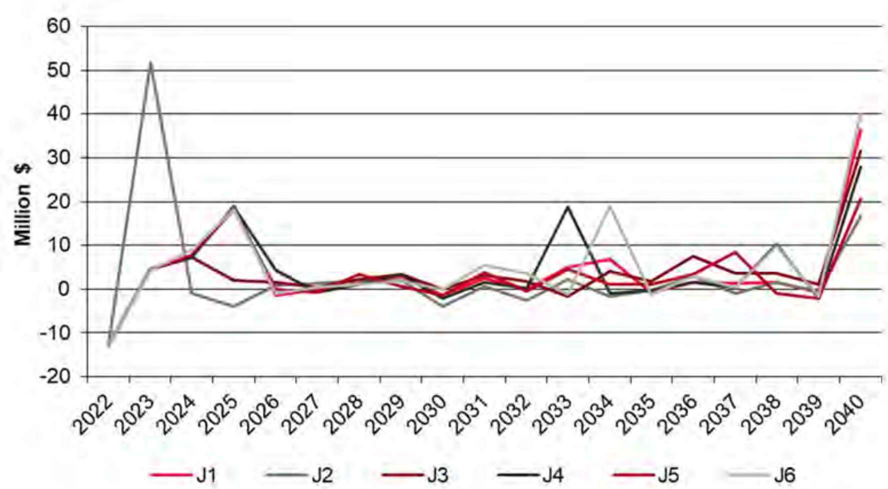
Figure 27 BHP All Scenarios – Incremental Annual Rate Increases



(Source: Energy Market Advisors)

Figure 28 Joint System All Scenarios – Incremental Annual Rate Increases



(Source: Energy Market Advisors)

The following series of graphs compares the Cumulative Capital Expenditures for BHP's, CLF&P's and the Joint System's portfolios.

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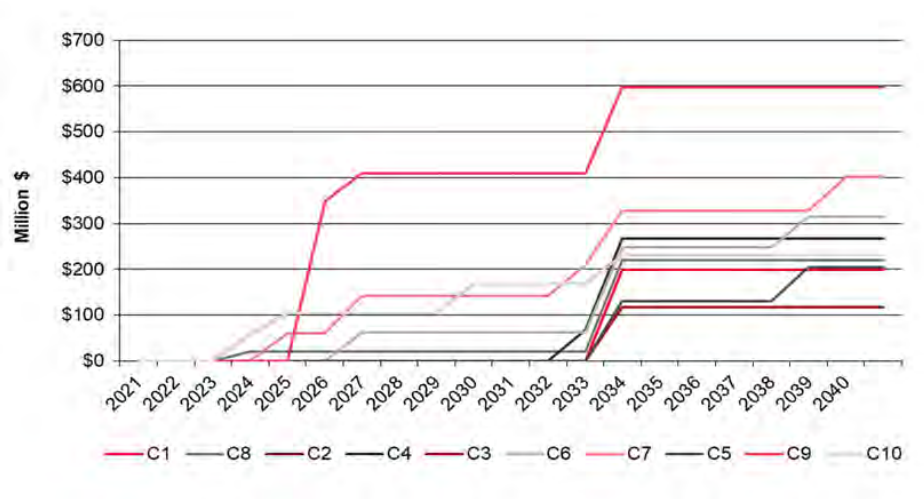
Figure 29 CLF&P All Scenarios – Cumulative Capital Expenditures



(Source: Energy Market Advisors)

Figure 30 BHP All Scenarios – Cumulative Capital Expenditures

(Source: Energy Market Advisors)

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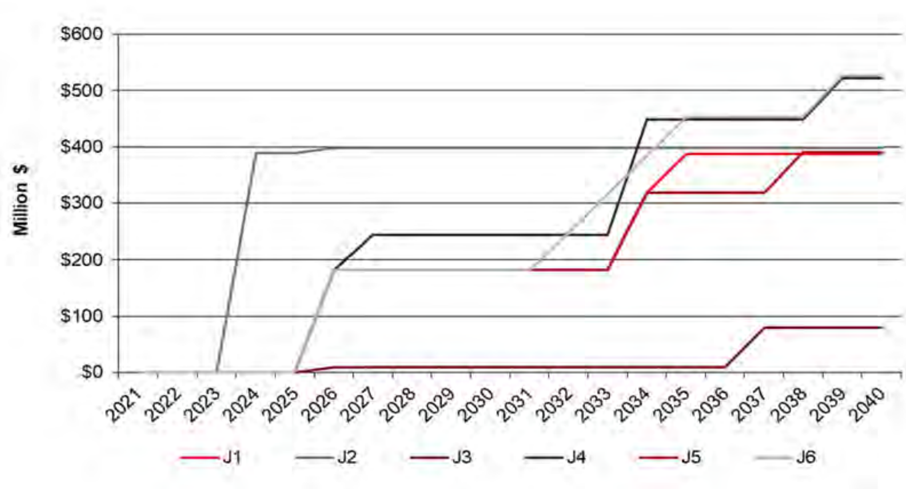
Figure 31 Joint System All Scenarios – Cumulative Capital Expenditures



(Source: Energy Market Advisors)

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7 Risk Analysis

7.1 Introduction

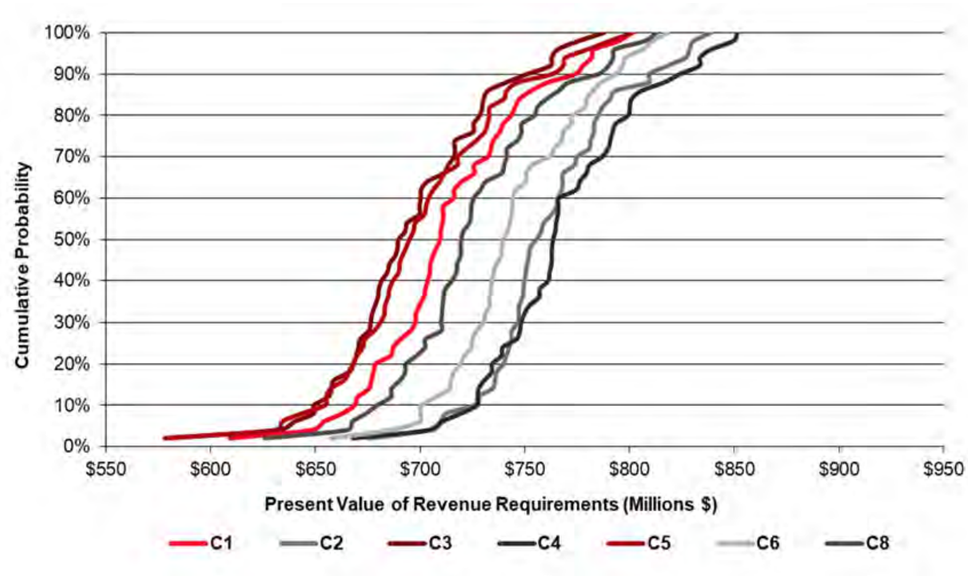
EMA utilized the Strategic Planning Risk Module to develop cumulative probability distributions which are also known as Risk Profiles.

7.2 Risk Profiles

Risk Profiles provide the ability to visually assess the risks associated with a decision under uncertainty. For this study, EMA combined the production cost model results with the financial results. Figure 32 and Figure 33 show the risk profiles for the CLF&P combined scenarios and portfolio C1. In Figure 32, Portfolios C3 & C5 are the closest to the left and therefore have the lowest PVRR in all years.

One can view the risk profile to determine the probability that PVRR will be a particular value. Using Portfolio C1 as an example, in Figure 33, there is a 90% probability that PVRR could be as much as $773.99 million with an expected value, or probably utility costs of $714.19 million. From the prior deterministic simulation, the PVRR value was $679.02 under direct utility costs or "median" conditions. The $35.17 million difference between the expected value and the deterministic value is "real option value" or extrinsic value. This reflects the risk of Portfolio C1 with future uncertainty.

Figure 32 CLF&P - Risk Profiles (2021-2040)



(Source: Energy Market Advisors)

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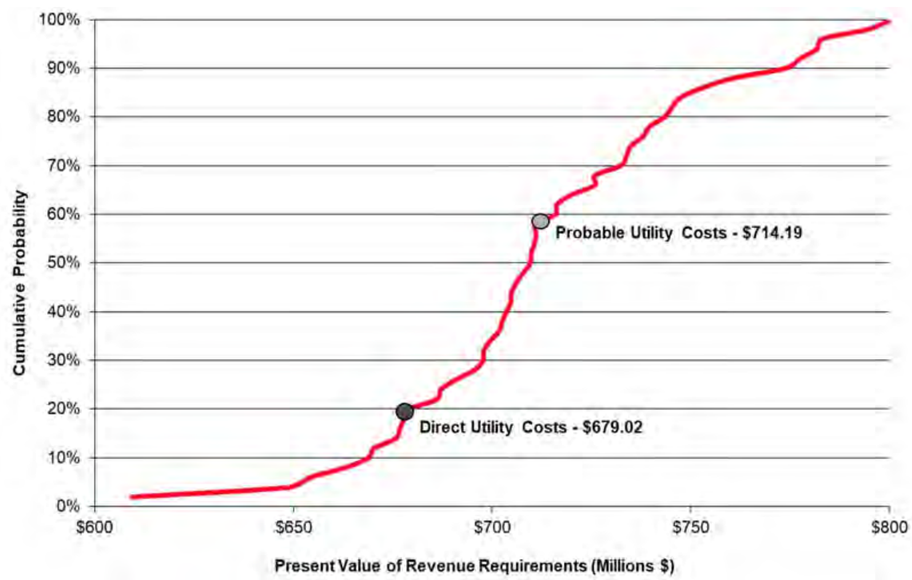
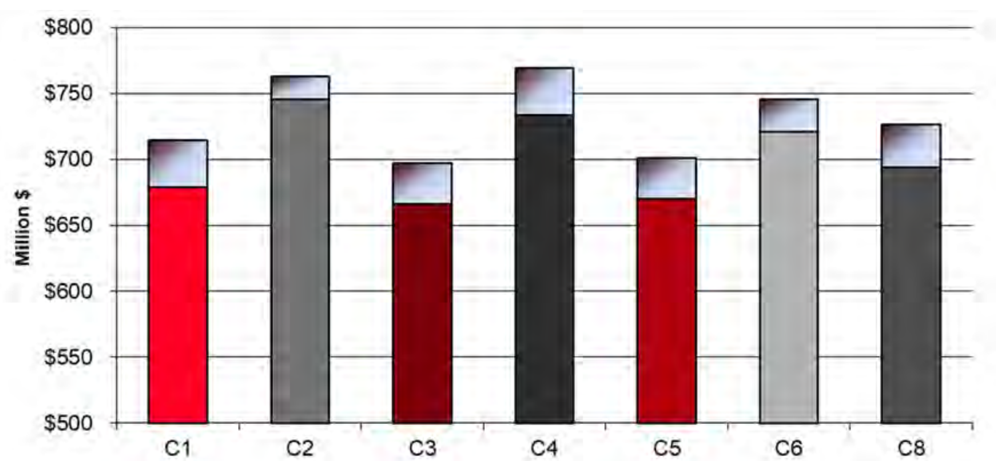
Figure 33 CLF&P C1 - Risk Profile (2021-2040)



(Source: Energy Market Advisors)

Figure 34 shows the “real option value” in table format. The extrinsic value is shaded in grey.

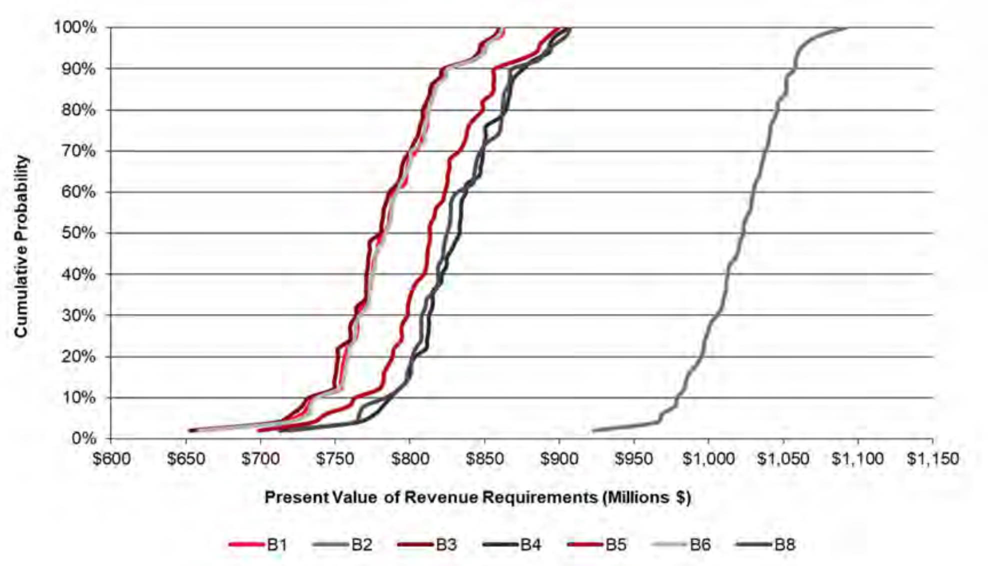
Figure 34 CLF&P - PVRR with Risk Value (2021-2040)



(Source: Energy Market Advisors)

Figure 35 shows the risk profiles for BHP portfolios B1 through B9. In Figure 35, Portfolios B1, B3 & B6 are the closest to the left and therefore have the lowest PVRR in all years. These portfolios also have deterministic values within $8.5 million of each other.

Figure 35 BHP - Risk Profiles (2021-2040)



(Source: Energy Market Advisors)

Again, one can view the risk profile to determine the probability that PVRR will be a particular value. Using Portfolio B1 as an example, as shown in Figure 36, there is a 90% probability that PVRR could be as much as $825.74 million with an expected value of $785.21 million. From the prior deterministic simulation, the PVRR value was $752.54 under "median" conditions. The $32.67 million difference between the expected value and the deterministic value is "real option value" or extrinsic value. This reflects the risk of Portfolio B1 with future uncertainty.

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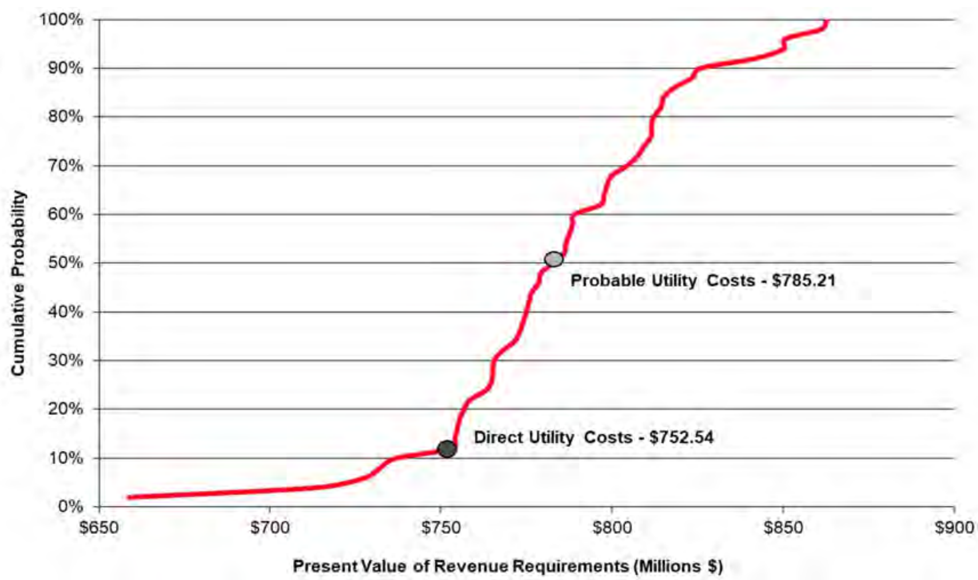
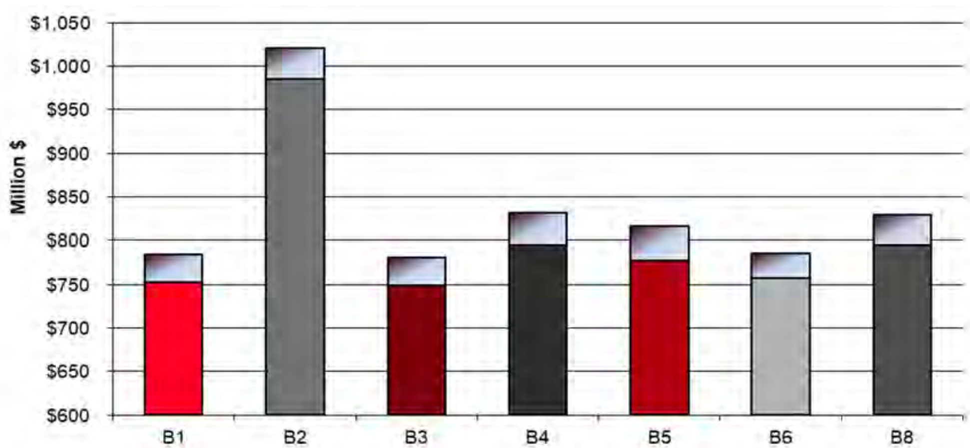
Figure 36 BHP B1 - Risk Profile (2021-2040)



(Source: Energy Market Advisors)

Figure 37 shows the “real option value” in a table format. The extrinsic value is shaded in grey.

Figure 37 BHP - PVRR with Risk Value (2021 - 2040)



(Source: Energy Market Advisors)

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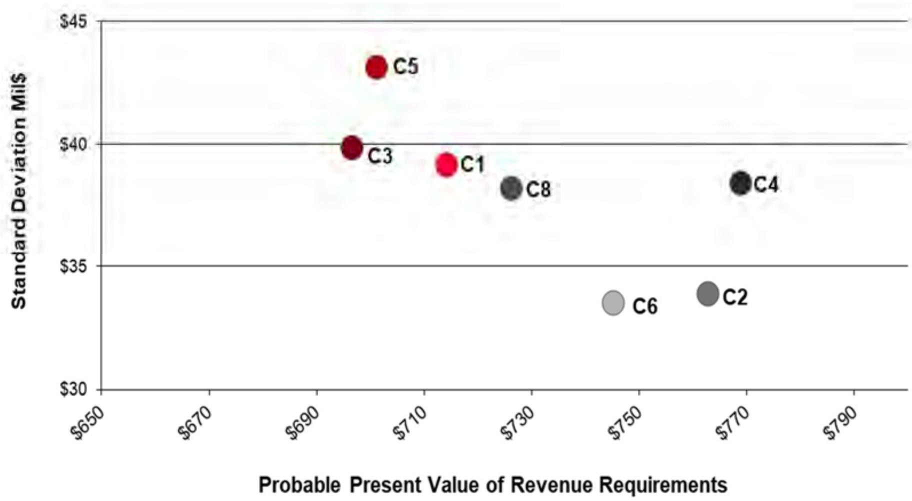
7.3 Trade-Off Diagram

EMA developed trade-off diagrams to evaluate the plans against CLF&P's and BHP's level of risk tolerance. Trade-off diagrams provide a means to quickly compare many plans using two measures such as least cost PVRR versus lowest risk (lowest volatility). In essence, a trade-off diagram summarizes the cost and risk measures of a Risk Profile. Figure 38 shows that for CLF&P, Portfolio C3 has the lowest PVRR whereas Portfolio C6 has the lowest standard deviation.

Figure 38 CLF&P - Trade-Off Diagram



(Source: Energy Market Advisors)

For BHP, Figure 39 shows that, like the Risk Profiles, there is little difference between Portfolios B1, B3 & B6 PVRRs and standard deviations.

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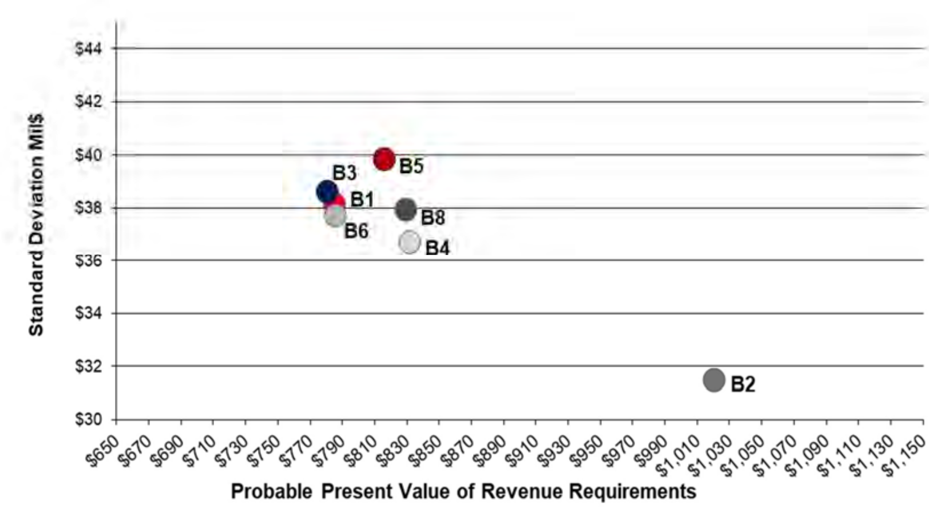
Figure 39 BHP - Trade-Off Diagram



(Source: Energy Market Advisors)

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Appendix A Software Used for Analysis

The Company uses Capacity Expansion to produce unique resource portfolios across a range of different planning assumptions. Capacity Expansion's core logic handles both Capacity Expansion and Emissions Compliance decisions. The primary feature of Capacity Expansion is its ability to analyze renewable portfolio standards and emissions regulations. Renewable portfolio standards can be modeled for the entire portfolio or for multiple jurisdictions. In addition, Capacity Expansion will also consider a wide range of emissions constraints for multiple emissions. Capacity Expansion is used in conjunction with other e7 solutions, such as Portfolio Optimization, when more detailed modeling is preferred. The e7 system allows resource plans to be saved and used in Portfolio Optimization and PROMOD® solutions to provide full hourly chronological simulations to provide operation level detail.

The Capacity Expansion model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability and other constraints. Over the 20-year planning horizon, it optimizes resource additions subject to resource costs and capacity constraints (summer peak loads plus a planning reserve margin). In the event that the retirement of an existing generating resource or contract expiration is assumed for a given planning scenario Capacity Expansion will select additional resources as required to meet summer peak loads inclusive of a target planning reserve margin. To accomplish these optimization objectives, Capacity Expansion performs a time-of-day least cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts within a transmission system. Resource dispatch is based on a representative-week method. Dispatch determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, spot market purchase costs, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), and amortized capital costs for potential new resources.

Portfolio Optimization (PO) software was used to analyze, report, and estimate the optimal dispatch of the Capacity Expansion generation portfolios against either a market price or a load requirement. PO produces optimal operating schedules for the entire portfolio of generation assets and transactions. The solution optimizes a portfolio's operation by modeling detailed unit operating constraints and market conditions to provide a generation schedule for energy and ancillary services, fuel nominations, support the evaluation and pricing of potential short-term transactions, and facilitate the analysis and simulation of deterministic and stochastic scenarios. The mixed-integer linear programming (MILP) based solution optimizes a variety of thermal units, such as simple cycle and combined cycle units, combined heat and power stations, independent and pump storage hydro units, complex cascaded hydro systems, and renewables including battery storage in a single solution. PO also optimizes a combined portfolio of supply resources (traditional generation) and demand response/distributed generation assets modeled as virtual power plants (VPPs).

e7 Portfolio Optimization Stochastic Analysis component was used to simulate uncertainties in electric and fuel prices, loads, energy availability as well as other factors that could contribute results. The component is a shared e7 service that is incorporates a Regression Tool, Draw Generation, and Stochastic Analysis.

Strategic Planning powered by MIDAS Gold® was utilized for the financial and risk modelling. Strategic Planning includes multiple modules for an enterprise-wide strategic solution. These modules are: Markets, Capacity Expansion, Portfolio, Financial, and Risk. The financial and risk modules were the only modules used for the 2021 IRP.

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The financial module allows the user the ability to model other financial aspects regarding costs exterior to the operation of units and other valuable information that is necessary to properly evaluate the economics of a generation fleet. The financial module produces bottom-line financial statements to evaluate profitability and earnings impacts.

The Risk module provides users the capability to perform stochastic analyses on all other modules and review results numerically and graphically. Stochastics may be performed on both production and financial variables.

Strategic Planning uses a Latin Hypercube-based stratified sampling program which takes into account statistical distributions, correlations, and volatilities for three time periods (i.e. Short-Term hourly, Mid-Term monthly, and Long-Term annual) for each transact group. Stratified sampling can be thought of as “smart” Monte Carlo sampling. Instead of drawing each sample from the entire distribution – as in Monte Carlo sampling – the sample space is divided into equal probability ranges and then a sample is taken from each range.

O. DEMAND-SIDE MANAGEMENT SURVEY

In early 2021, Cheyenne Light and Black Hills Power sent a survey to customers with loads equal to or exceeding 2 MW to assess their interest in participating in a DSM demand response program. This appendix contains the results of that survey and the actual survey.

Survey Results

Cheyenne Light and Black Hills Power received limited responses, and the potential for the program indicated minimal participation (Table O-1). As a result, neither utility will be developing a demand response program at this time.

Black Hills Power Response	Cheyenne Light Response	Response
2	2	Yes
2	0	Maybe
7	3	No
4	2	Did Not Respond
15	8	Total Customers Surveyed

Table O-1. Demand Response DSM Survey Results

Customer DSM Demand Response Survey

Subject: BHE Demand Side Management Survey

Greetings,

Black Hills Energy's Integrated Resource Plan looks years ahead to ensure safe, reliable service where and when its needed. We also strive to develop innovative solutions that create value. Currently, there isn't a comprehensive Demand Side Management program at BHE, so we're reaching out to gauge the interest of large commercial and industrial customers.

Considering this, I invite you to answer a few questions regarding Demand Side Management (DSM):

- Utilizing DSM guidelines, is your business compatible with curtailing a portion of electrical load at any given time? Curtailment is reducing load within a few hours' notice and does not entail shifting load to alternative hours.
- What is the estimated load ______ (kW or percent of total load) that could be curtailed?
- What is the frequency your business is willing to curtail?

  ______ hours ______ day ______ week ______ month
- If BHE offered a DSM program that helps customers with loads greater than 2 MW manage their energy costs, would your business be interested?

We understand that some customer's operational needs aren't compatible with DSM, while others may be interested in exploring a curtailment strategy.

Thank you for your feedback and partnership.

Signed
Key Account Manager