February 11, 2021 **PUBLIC DOCUMENT**

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E002/RP-19-368

Dear Mr. Seuffert:

Attached are the Comments of the Minnesota Department of Commerce, Division of Energy Resources (Department), in the following matter:

2020-2034 Upper Midwest Integrated Resource Plan.

The Petition was filed on July 1, 2019 (as supplemented on June 30, 2020) by:

Christopher B. Clark
President
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401

The Department recommends that the Minnesota Public Utilities Commission (Commission) **approve the petition with modifications**. The Department's team of Danielle Winner, Matthew Landi, Sachin Shah and myself is available to answer any questions that the Commission may have in this matter.

Sincerely,

/s/ STEVE RAKOW
Analyst Coordinator

SR/ar
Attachment

 PUBLIC DOCUMENT

Table of Contents

 PUBLIC DOCUMENT

 PUBLIC DOCUMENT

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

PUBLIC Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. E002/RP-19-368

I. INTRODUCTION

A. DOCKET HISTORY

1. First Round

On July 1, 2019 Northern States Power Company-Minnesota (NSP-M), doing business as Xcel Energy (Xcel or the Company) filed the Company's *2020-2034 Upper Midwest Integrated Resource Plan* (Petition). The Petition was filed in compliance with the Minnesota Public Utilities Commission's (Commission) January 30, 2019 *Order Extending Deadline for Filing Next Resource Plan* (2019 Order) and January 11, 2017 *Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings* (2017 Order) in Docket No. E002/RP-15-21.

On July 3, 2019 the Commission issued its *Notice of Comment Period* (Notice) which stated that comments on the Petition are due November 8, 2019 and January 8, 2020. The Notice also indicated that comments on completeness were due August 1, 2019.

On July 18, 2019 the Commission issued its *Order Requiring Bill Insert and Referring Matter to OAH for Public Meeting* (Meeting Order). The Meeting Order established a process for holding public meetings to ensure that Xcel's customers have an opportunity to participate in the IRP process.

On July 25, 2019 the Department filed a letter recommending that the Commission not undertake a completeness review.

In response to the Meeting Order, on July 30, 2019 the Minnesota Office of Administrative Hearings (OAH) issued OAH's *Scheduling Order*, establishing October 21, 23, 28, and 30 as dates for public meetings.

On July 31, 2019 the city of Minneapolis filed a letter on completeness.

On October 8, 2019 Xcel filed a letter indicating that the Company could:

- provide updated Strategist modeling in a new filing by December 6, 2019;
- participate with other utilities in a planning meeting to cover the new capacity expansion modeling (CEM) tool (Encompass), along with a variety of topics; and
- provide a supplemental filing in the April 2020 timeframe using EnCompass.

On or about October 15, 2019 the following organizations and coalitions filed comments on modifying the comment deadlines:

- Sierra Club, Vote Solar, and the Institute for Local Self-Reliance;
- Clean Energy Organizations (CEO);[1]
- Citizens Utility Board of Minnesota;
- Xcel Large Industrials (XLI);[2]

On November 12, 2019 the Commission issued its *Order Suspending Procedural Schedule and Requiring Additional Filings* (Supplemental Order). The Supplemental Order:

- suspended the procedural schedule;
- required Xcel to file certain supplemental information; and
- delegated to the Executive Secretary the establishment of a new procedural schedule—but stated that Xcel's supplement could be filed no later than July 1, 2020.

On December 18, 2019 the OAH filed its *Report Summarizing Public Meetings* which summarized the public comments obtained at the October public meetings regarding the Petition.

2. *Second Round*

On December 6, 2019 the Commission issued a notice indicating that:

- Xcel must file a supplement by April 1, 2020;
- comments are due August 3, 2020; and
- reply comments are due October 2, 2020.

On February 12, 2020 the Minnesota Sustainable Growth Coalition (MSG) filed comments on behalf of MSG's non-utility members regarding Xcel's proposed plan.[3]

On March 6, 2020 Xcel filed the Company's *Extension Request*, requesting an extension for the supplemental filing to May 15, 2020 in light of the need to conduct a substantial update of the Strategist modeling, and to implement the EnCompass model, including development of more granular modeling inputs for hourly analysis.

On March 11, 2020 the Commission issued its *Notice Approving Extension Request and Extending Comment Periods* establishing a new deadline for Xcel's supplement and for filing initial comments and reply comments.

On March 13, 2020 International Brotherhood of Electrical Workers locals 23, 160, and 949 filed comments regarding Xcel's proposed plan.

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[1] The CEO coalition consists of Clean Grid Alliance, Fresh Energy, Minnesota Center for Environmental Advocacy, and the Union of Concerned Scientists.
[2] The XLI coalition consists of Covia Holdings Corporation; Flint Hills Resources Pine Bend, LLC; Gerdau Ameristeel US Inc.; Marathon Petroleum Corporation; and USG Interiors, Inc.
[3] MSG's non-utility members come from the private, public, and non-profit sectors.

On April 10, 2020 Xcel filed the Company's *Extension Request*, requesting a second extension for the supplemental filing to June 30, 2020 in light of the ongoing COVID-19 public health emergency.

On April 16, 2020 the Commission issued its *Second Notice Approving Extension Request and Extending Comment Periods* stating that:

- the deadline for Xcel's supplement is June 30, 2020;
- the deadline for filing initial comments is October 30, 2020; and
- the deadline for filing reply comments is January 15, 2021.

On June 30, 2020 Xcel filed the Company's *Supplement to the Petition* (Supplement).

On September 15, 2020, at the request of the Department, the Commission established January 15, 2021 as the due date for comments and March 15, 2021 as the due date for reply comments.

On December 23, 2020 the Department issued Global Energy & Water Consulting, LLC's (Global) *Independent Investigation of Cost Overruns and Cost Estimates for Xcel Energy's Monticello and Prairie Island Nuclear Power Plants* (Report). The Department retained Global to prepare the Report in compliance with the Commission's March 26, 2019 *Order Authorizing Commissioner of Commerce to Seek Funding For Specialized Technical Professional Services Under Minn. Stat. § 216B.62 Subd. 8* in Docket Nos. E002/RP-15-21 and E002/GR-15-826:

> The Commission authorizes the Commissioner of the Department of Commerce to seek authority from the Commissioner of Management and Budget to incur costs for specialized technical professional investigative services under Minn. Stat. § 216B.62, subd. 8, to continue investigating the causes of cost increases related to Xcel's Prairie Island and Monticello nuclear facilities and to assist the Department in Xcel's upcoming integrated resource plan and rate case proceedings.

On December 28, 2020, at the Department's request, the Commission established February 11, 2021 as the due date for comments and April 12, 2021 as the due date for reply comments.

In January and February, 2021, comments were filed by MSG on behalf of MSG's non-utility members; the Prairie Island Indian Community, a federally recognized Indian tribe; Goodhue County Board of Commissioners; the St. Paul Area Chamber; Board of Wright County Commissioners; Northern Natural Gas; and other organizations.

Numerous members of the public filed comments throughout this proceeding.

B. COMPANY BACKGOUND

The Petition and Supplement cover Xcel's upper Midwest service territory, including parts of Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. According to the U.S. Energy Information Administration's Form 861 for 2017, NSP-M has about 1.46 million electricity customers in total, spread across Minnesota (1.28 million), North Dakota (90,000), and South Dakota (90,000). Xcel's Wisconsin subsidiary has about 257,000 electricity customers located in Michigan (9,000) and Wisconsin (248,000). NSP-M electricity customers in Minnesota are primarily located in the twin cities area, but Xcel also provides electricity to customers in St. Cloud, Red Wing, Mankato, and several other communities.

The Company planned to meet an estimated peak demand of about 10.4 GW before energy efficiency and load management in 2018. In addition, the Company must have about 0.3 GW of resources above peak demand to meet reliability requirements. The portfolio of resources used to meet this peak demand and reliability requirements in 2018 included:

- 1.3 GW of energy efficiency;
- 0.8 GW of load management;
- 12.7 GW[4] of supply-side resources, including;
    - 0.7 GW of hydro;
    - 0.6 GW of solar;[5]
    - 2.7 GW of wind;[6]
    - 2.4 GW of coal;
    - 1.7 GW of nuclear;
    - 2.0 GW of natural gas combined cycle (CC);
    - 2.0 GW of natural gas combustion turbine (CT);
    - 0.4 GW of fuel oil CT; and
    - 0.2 GW of other fuels.[7]

C. XCEL'S RESOURCE NEEDS

Table 1 below, taken from Table 2-2 in Xcel's Supplement, shows the Company's projected resource needs over the planning period. These are the needs before any new actions. For example, it considers existing and approved resources only and takes into account current unit retirement and contract expiration dates. This means Table 1 assumes the Company's nuclear units operate to the end of the current license life and committed units come on-line (such as the 728 MW Sherco combined cycle generating unit (Sherco CC) in 2027).

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[4] For reliability purposes supply-side resources are measured using "unforced capacity." Unforced capacity is equal to the installed capacity less a discount factor which accounts for periods when the power plant is not operational (forced outages). For larger, dispatchable resources the discount factor calculated by MISO is typically less than 15 percent.
[5] Solar resources are typically measured using a discount factor for reliability purposes of about 50 percent as calculated by MISO.
[6] Wind resources are typically measured using an 80 percent to 85 percent discount for reliability purposes as calculated by MISO.
[7] Other includes biomass, landfill gas, refuse-derived fuel (RDF), and methane digesters. All data taken from the file SO - _SCENARIO 1.xlsm, provided in response to Department IR No. 4.

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Table 1: Xcel's Resource Needs 2020-2034

Year	Resource Need (MW)
2020	1,394
2021	1,871
2022	2,002
2023	2,052
2024	1,311
2025	195
2026	(92)
2027	(334)
2028	(386)
2029	(365)
2030	(1,016)
2031	(1,605)
2032	(1,945)
2033	(2,602)
2034	(3,166)

Table 1 shows that Xcel expects a need to acquire new capacity resources—or extend the life of current resources—around 2026 or 2027. However, substantial resource needs are not encountered until 2030.

D. XCEL'S PROPOSED ACTION PLAN

In the Supplement, Xcel proposed the following five-year (2020-2024) action plan. Overall, the Company's preferred plan does not identify any incremental capacity needs through 2024. Thus, the majority of Xcel's proposed actions address previously approved or pending resource additions and retirements.

Regarding wind resources, Xcel expected that wind generation resulting from recent acquisitions will achieve commercial operation by 2022. If Xcel encounters opportunities to repower existing resources, or if specific customer needs require procurement, the Company will pursue the opportunities. Finally, Xcel intends to issue a request for proposals (RFP) for repowering of existing wind resources.[8]

Regarding solar resources, Xcel expected to start an RFP process in the 2023 to 2024 timeframe. Xcel has proposed the addition of up to 460 MW of solar capacity, to interconnect at the Sherco substation.[9] This would meet the proposed addition of about 500 MW of large-scale solar resources in 2025 in the Company's preferred plan.[10]

Regarding hydro resources, Xcel will add 125 MW of energy and capacity through an existing, Commission-approved power purchase agreement (PPA) with Manitoba Hydro in 2021.

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[8] While the magnitude of the capacity resulting from the RFP cannot be known, Xcel estimates about 800 MW to 1,000 MW could result. See Xcel's June 17 Report in Docket No. E,G999/CI-20-492 for details.

[9] See Xcel's June 17 Report in Docket No. E,G999/CI-20-492 for details.

[10] Note that Xcel included forecasted growth of distributed solar in the overall planning process.

Regarding nuclear resources, Xcel expected to file a certificate of need proposing a life extension at the Monticello Nuclear Generating Plant (Monticello) with the Commission. Xcel also expects to begin working toward a license extension with the U.S. Nuclear Regulatory Commission during this timeframe.

Regarding natural gas and oil resources, Xcel anticipated extending the life of Blue Lake units 1 to 4 through 2023 and continue development of the Sherco CC unit. Finally, the Company notes that Xcel is analyzing the Company's black-start plan. For now, the plan includes costs and capacity associated with black-start facilities.

Regarding coal resources, Xcel proposed to retire the remaining coal units (Sherburne County Generating Station (Sherco) unit 3 and the Allen S. King Generating Plant (King)) by the end of 2030, but after the five-year action plan. Xcel continued to assume Sherco units 1 and 2's currently approved retirement dates of 2026 and 2023.

Regarding load management resources, Xcel proposed to acquire 400 MW by 2023.

Regarding energy efficiency, Xcel proposed to acquire average estimated energy savings of about 780 GWh annually.

Regarding supporting infrastructure, Xcel expected the Huntly-Wilmarth project to be completed in late 2021.[11] Xcel also plans to install new electric meters and supporting infrastructure to facilitate load management and energy efficiency resources.

II. DEPARTMENT ANALYSIS

A. APPLICABLE STATUES AND RULES

The Commission's IRP process is governed by Minnesota Statutes § 216B.2422 which states in part:

> subd. 2. Resource plan filing and approval. (a) A utility shall file a resource plan with the Commission periodically in accordance with rules adopted by the Commission. The Commission shall approve, reject, or modify the plan of a public utility, as defined in section 216B.02, subdivision 4, consistent with the public interest.
>
> …
>
> (c) As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources.
>
> subd. 2a. Historical data and advance forecast. Each utility required to file a resource plan under this section shall include in the filing all applicable annual information required by section 216C.17, subdivision 2, and the rules adopted under that section. To the extent that a utility complies with this subdivision, it is

[11] See Docket No. E002, ET6675/CN-17-184.

not required to file annual advance forecasts with the department under section 216C.17, subdivision 2.

…

subd. 2c. Long-range emission reduction planning. Each utility required to file a resource plan under subdivision 2 shall include in the filing a narrative identifying and describing the costs, opportunities, and technical barriers to the utility continuing to make progress on its system toward achieving the state greenhouse gas emission reduction goals established in section 216H.02, subdivision 1, and the technologies, alternatives, and steps the utility is considering to address those opportunities and barriers.

subd. 3. Environmental costs. (a) The Commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the Commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the Commission, including resource plan and certificate of need proceedings.

…

subd. 4. Preference for renewable energy facility. The Commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the Commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. When making the public interest determination, the Commission must consider:

(1) whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f;

(2) impacts on local and regional grid reliability;

(3) utility and ratepayer impacts resulting from the intermittent nature of renewable energy facilities, including but not limited to the costs of purchasing wholesale electricity in the market and the costs of providing ancillary services; and

(4) utility and ratepayer impacts resulting from reduced exposure to fuel price volatility, changes in transmission costs, portfolio diversification, and environmental compliance costs.

…

> subd. 7. Energy storage systems assessment. (a) Each public utility required to file a resource plan under subdivision 2 must include in the filing an assessment of energy storage systems that analyzes how the deployment of energy storage systems contributes to:
> (1) meeting identified generation and capacity needs; and
>
> (2) evaluating ancillary services.
>
> (b) The assessment must employ appropriate modeling methods to enable the analysis required in paragraph (a).

The Commission's IRP process is also governed by Minnesota Rules parts 7843.0100 to 7843.0600 which states, in part:

> subp. 3. Factors to consider. In issuing its findings of fact and conclusions, the Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to:
> A. maintain or improve the adequacy and reliability of utility service;
> B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
> C. minimize adverse socioeconomic effects and adverse effects upon the environment;
> D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
> E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

In summary, the Commission evaluates a proposed IRP based upon its ability to create a reliable, low cost, low environmental and socioeconomic impact system that manages risk. In weighing these factors, the Commission considers the statutory preference for renewable energy facilities. As indicated in the Petition's Attachment A, there are numerous other statutes, rules, and Commission orders which impact the decision in this proceeding.

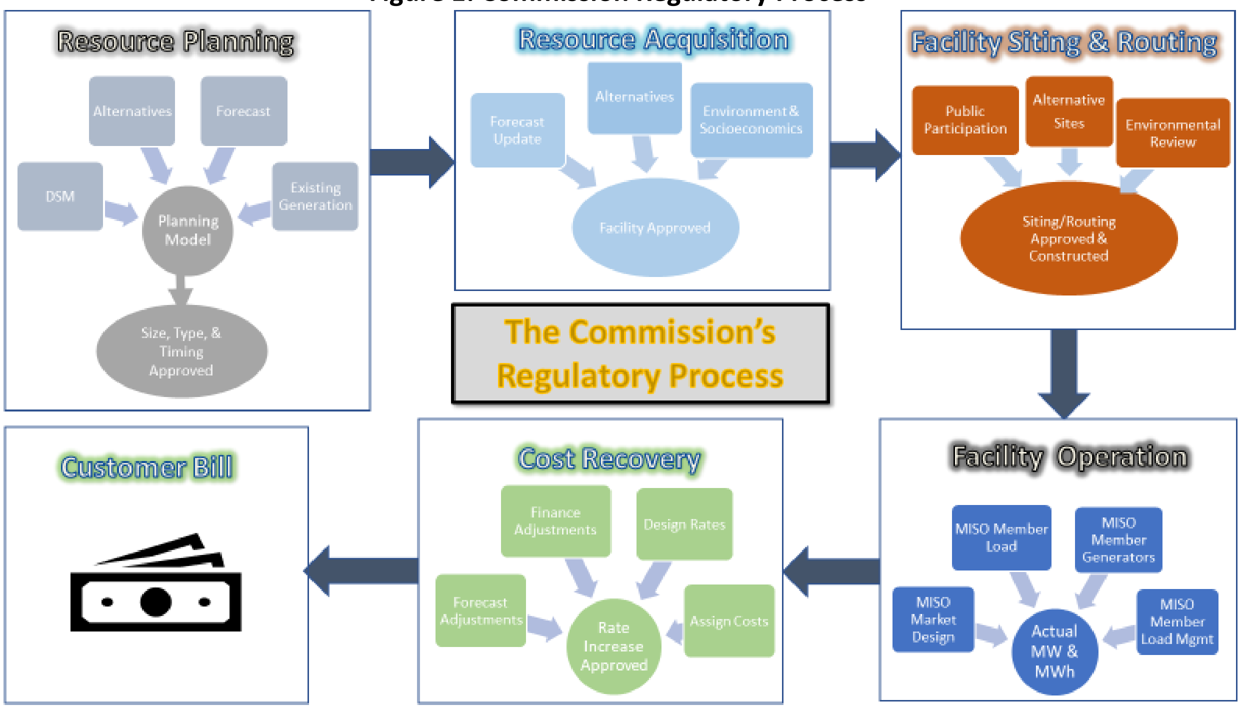
Regarding the proposal to shut down the coal plants early, the Department notes that Minnesota Statutes § 216B.16, subd 6 states:

> If the Commission orders a generating facility to terminate its operations before the end of the facility's physical life in order to comply with a specific state or federal energy statute or policy, the Commission may allow the public utility to recover any positive net book value of the facility as determined by the Commission.

B. OVERVIEW OF DEPARTMENT ANALYSIS

An IRP is the first step in the Commission's overall regulatory process. The Commission's regulatory process as applied to generation units is illustrated in Figure 1 below.

Figure 1: Commission Regulatory Process



For Xcel's 2020-2034 IRP, the Department:

- reviewed the accuracy of the Company's 15-year energy and demand forecast process;[12]
- produced a Department reference case based on changes to Xcel's modeling;
- assessed different scenarios, including various shutdown dates for Sherco unit 3, King, Monticello, and the Prairie Island nuclear generating plant (Prairie Island);
- chose a preferred plan; and
- recommended improvements to the bidding process to acquire resources.

Given the significant surplus that Xcel expects through 2024, the Department was not surprised to find that its modeling resulted in the same five-year action plan as Xcel's—that is no supply-side units are needed.

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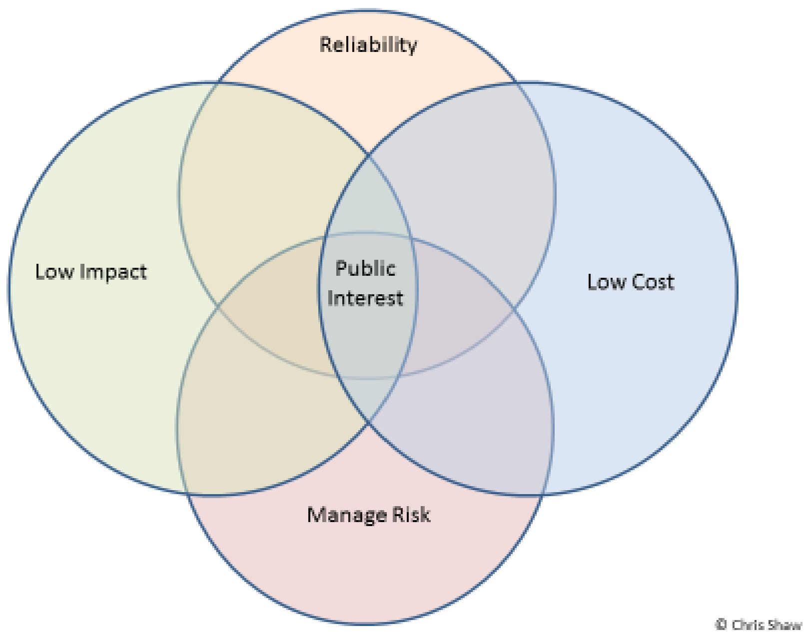
[12] As discussed further below, this means the Department did not review the technical details of Xcel's forecast. Instead, the Department reviewed the overall accuracy of Xcel's forecast process over the past 15 years.

Similar to Xcel, the Department's recommendation for a preferred plan is based upon the overall resource planning goals of maintaining a reliable, low cost, low impact system that manages risk; this balancing of goals is illustrated in Figure 2 below.

Figure 2: Balancing Four IRP Goals[13]



Under Minnesota Rules 7843.0600, subp. 2 the consequences of the Commission's order in this proceeding are clear:

> the findings of fact and conclusions from the Commission's decision in a resource plan proceeding may be officially noticed or introduced into evidence in related Commission proceedings … In those proceedings, the Commission's resource plan decision constitutes prima facie evidence of the facts stated in the decision."

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[13] Each of the four goal is embedded in numerous Minnesota Statutes and Minnesota Rules. For further details see the *Direct Testimony and Attachments of Dr. Steven Rakow* at Department Ex. __ SRR-2 (Docket No. E015/AI-17-568). Examples of each goal from the Commission's resource planning decision criteria:

- reliability—7843.0500 subp. 3 A—ability to maintain or improve the adequacy and reliability of utility service;
- cost—7843.0500 subp. 3 B—keep the customers' bills and the utility's rates as low as practicable;
- risk—7843.0500 subp. 3 E—risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control; and
- impact—7843.0500 subp. 3 C—minimize adverse socioeconomic effects and adverse effects upon the environment.

C. DEMAND AND ENERGY FORECAST

1. Introduction

For this IRP, the Department neither reviewed the technical details of Xcel's forecast nor tested all the Company's previous or current statistical models. Instead, the Department examined the accuracy of Xcel's forecasting over the past 15 years. As described below, our review indicates that the Company's demand and energy forecasts have a systematic bias. Consequently, for this IRP, the Department adjusted Xcel's forecast to account for the bias and used the adjusted forecast to evaluate capacity expansion plans.

The Department conducted a similar analysis of Minnesota Power, a division of ALLETE, Inc.'s (MP) historical forecasting for MP's 2015 IRP (See the Department's March 4, 2016 *Reply Comments* in Docket No. E015/RP-15-690, pages 5 to 10). Table 2 below summarizes the relevant data for MP's demand forecast process. Note that the equivalent data for MP's energy forecast process is similar. In this case, MP's data can be used as a standard of comparison to gauge the quality of Xcel's forecasts. Generally speaking, a review of how well a forecast predicts usage over a prior period is a good indicator of the quality of the overall forecasting process.

In reviewing Table 2 the first thing to focus on is whether the data points tend to be:

- below zero—the demand forecast was too low[14];
- above zero—the demand forecast was too high[15]; or
- neither higher nor lower than forecasted.

[14] Actual demand was higher than forecasted.

[15] Actual demand was lower than forecasted.

Table 2: Percent Error in MP's Demand Forecast

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Forecast Vintage	AFR 2000	0.9%	13.7%	-5.6%	-1.3%	-3.1%	-6.8%	-8.5%	-7.5%	-3.1%	23.6%	-2.2%	-1.6%	-2.8%	-0.2%
	AFR 2001		5.2%	-0.5%	4.0%	1.8%	-2.5%	-4.6%	-3.8%	0.5%	28.0%	1.4%	2.4%	1.2%	2.9%
	AFR 2002			-2.0%	5.0%	3.5%	-0.6%	-2.6%	-1.9%	2.3%	30.7%	2.4%	3.1%	1.4%	2.7%
	AFR 2003				2.4%	-4.4%	-6.4%	-6.9%	-8.2%	-3.1%	24.6%	-2.9%	-1.7%	-2.2%	-1.7%
	AFR 2004					0.0%	0.0%	-3.9%	-3.5%	3.7%	30.8%	1.7%	4.8%	4.1%	5.6%
	AFR 2005						-5.0%	-6.9%	-6.3%	3.1%	30.7%	2.5%	3.3%	2.0%	4.4%
	AFR 2006							-0.2%	-0.7%	4.5%	34.3%	5.9%	7.0%	6.0%	7.5%
	AFR 2007								-2.4%	2.2%	31.4%	3.5%	4.8%	3.6%	5.2%
	AFR 2008									2.5%	31.0%	3.2%	3.7%	2.4%	3.6%
	AFR 2009										0.0%	-21.1%	-15.6%	-11.9%	-8.9%
	AFR 2010											-0.1%	-1.4%	-2.6%	-1.5%
	AFR 2011												-1.5%	-3.5%	-2.4%
	AFR 2012													-3.7%	-3.0%
	AFR 2013														-2.8%

For easy identification, the Department shaded cells in Table 2 that are negative. Review of Table 2 shows that 50 percent of the demand forecast data points[16] were above zero (too high), 48 percent were below zero (too low), and the rest were correct. Based upon this data, the Department concluded in MP's IRP that there was no evidence of systematic bias in MP's demand forecast processes. This means that MP's forecast process did not systematically over-forecast or under-forecast demand. Similar results were obtained when the Department reviewed MP's energy forecast process. This result is important because, while it is known that all forecasts are wrong in the sense that they will not be equal to the actual value, for the forecast to be useful it should be unbiased. Here, by unbiased, the Department means that the actual values are as likely to be above the forecast as they are likely to be below the forecast. If a forecast is unbiased, in the long run the average error should be approximately zero. If there is a systematic bias that results in over-forecasting or under-forecasting, the need for additional resources will be overstated or under-stated. The resulting risk is that a utility builds unnecessary resources or is unable to provide adequate resources to meet actual demand.

The second thing to note when reviewing Table 2 is the specific numbers that show the difference between the actual result and the forecast. About 71 percent of MP's data points (demand forecast process shown in Table 2) and 72 percent of MP's data points (energy forecast process —not shown here) were within a ±5 percent (high and low) forecast band. Based upon this data, the Department concluded that use of a ±5 percent was sufficient to capture a reasonable portion of the uncertainty inherent in MP's future demand requirements.

Given the valuable insights produced by the analysis of MP's forecast process the Department performed a similar analysis for Xcel. The purpose was the same, to check for evidence of systematic bias in Xcel's forecast process and also to determine the appropriate forecast bands to use for Xcel's IRP.

2. Data Analyzed

The Department began by reviewing the data provided by Xcel in response to Sierra Club Information Requests (IR) Nos. 42 (historic actual demand and energy requirements) and 45 (past forecasts). However, Xcel's response to the Sierra Club provided multiple answers regarding measures of historic energy requirements. Therefore, Department IR Nos. 62 and 63 requested Xcel explain which measure of historic energy and demand requirements was comparable to the forecasts. Xcel's response provided data on historic energy and demand requirements that was comparable to the past forecasts.

After reviewing the data, the Department determined that additional data was required on historic actuals and past forecasts. In addition, the Department noted what appeared to be potential discrepancies in the data provided by Xcel. Therefore, through Department IR Nos. 64 to 68 the Department requested additional explanations, data on past actuals back to 2004, and past forecasts back to 2003. This additional data enabled the Department to review the forecast process for a duration approximately equivalent to an IRP planning period.

[16] Each year of a 15-year forecast was considered a separate data point for purposes of the analysis. The forecasts included were the Annual Forecast Reports (AFR) for years 2000 to 2013 and the actual demand and energy for 2000 to 2013. Thus, MP's forecast "AFR 2000" had 14 separate data points, one each for the years 2000 to 2013 while the forecast "AFR 2012" had only two separate data points, 2012 and 2013.

Using Xcel's responses, the Department compared actual energy sales (Department IR No. 64) and uninterrupted peak demand (Department IR No. 65) for the years 2004 to 2018 to Xcel's demand and energy forecasts (Department IR No. 66) from August 2003 to July 2018.[17]

3. Demand Forecast Process

The Department's first step in analyzing Xcel's demand forecast process was calculating the difference between forecasted demand and actual peak demand. The results of this calculation are shown below in Tables 3a and 3b. As with Table 2 showing data from MP, in Tables 3a and 3b a positive number indicates the forecast turned out to be too high and a negative number indicates that the forecast turned out to be too low. For easy identification, the Department shaded the cells in Tables 3a and 3b that are negative.

[17] Xcel produces multiple forecasts in most years thus there were a total of 31 different forecasts provided by Xcel.

Table 3a: Xcel's Demand Forecast Error, Pre-October 2008 (MW)

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Forecast Vintage	**Aug-03**	507	251	(313)	294	1,266	1,523	1,195	889	1,223	1,337	2,193	2,599	2,396	3,015	2,770
	Jun-04	470	200	(375)	187	1,144	1,380	1,032	709	1,034	1,131	1,975	2,371	2,168	2,781	2,546
	Feb-05		65	(458)	126	1,108	1,366	1,034	718	1,053	1,158	2,009	2,428	2,252	2,885	2,669
	Mar-06			(524)	111	1,106	1,431	1,123	841	1,186	1,333	2,209	2,646	2,465	3,148	2,944
	Sep-06			(498)	150	1,121	1,418	1,093	810	1,155	1,303	2,179	2,616	2,435	3,118	2,913
	Mar-07				104	1,100	1,337	1,028	727	1,068	1,160	2,014	2,406	2,210	2,807	2,595
	Oct-07				(46)	1,043	1,272	929	567	835	890	1,683	2,018	1,746	2,298	2,017
	Mar-08					977	1,241	862	469	747	817	1,608	1,952	1,686	2,245	1,944

Table 3b: Xcel's Demand Forecast Error, October 2008 to Present (MW)

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Forecast Vintage	Oct-08					873	1,053	612	196	451	504	1,279	1,606	1,322	1,866	1,550
	Apr-09						790	280	(167)	31	38	762	1,044	725	1,238	882
	Oct-09						6	149	(232)	29	26	744	1,009	672	1,165	796
	Apr-10							16	(293)	31	140	973	1,330	1,079	1,653	1,370
	Jul-10							55	(266)	41	99	891	1,205	912	1,442	1,114
	Apr-11								(483)	(230)	(231)	567	909	629	1,179	862
	Sep-11								169	(262)	(311)	453	776	487	1,027	716
	Mar-12									(508)	(510)	241	553	261	809	504
	Jul-12									3	(309)	432	749	438	971	641
	Mar-13										(350)	355	643	324	855	529
	Jul-13										(228)	507	813	494	1,006	654
	Sep-13										(352)	364	620	313	854	531
	Mar-14											440	703	394	918	587
	Aug-14											-	680	407	932	604
	Mar-15												622	357	900	558
	Jul-15												570	325	857	515
	Mar-16													140	689	326
	Aug-16													116	636	266
	Nov-16														633	262
	Mar-17														641	254
	Jul-17														590	260
	Mar-18															112
	Jul-18															181

When considering all forecasts, about 91 percent of the data points are positive and only nine percent are negative. When considering only the forecasts from October 2008[18] to present, about 88 percent of the data points are positive and only 12 percent are negative. Based upon this data the Department concludes that there is evidence of a systematic bias in Xcel's demand forecast process. In other words, the Company's demand forecast is consistently too high.

The Department's second step was to determine the size of the error (in MW) resulting from the demand forecast process. Due to the change in Xcel's forecast process, the Department focused on the error for the demand forecasts starting in October 2008; the error was calculated for the first forecast year, the second forecast year, and so on. The result was that one year out the average error is about 175 MW, which is small considering the size of Xcel's system. Three years out Xcel's average error is about 325 MW, about the size of a large combustion turbine or the initial accredited capacity expected from about 650 MW of solar. By five years out Xcel's average error is about 625 MW or two large CT units and by eight years out the average error is about 1,100 MW. Thus, the size of the error consistently grows the further into the future the calculations are taken. The Department considered this degree of error when determining the forecast bands used by the Department in its modeling, as explained below.

The Department's third step was to calculate the percent error in order to help determine the appropriate forecast adjustment and forecast bands. The result of this calculation is shown below in Tables 4a and 4b. As above, the focus is on the forecast vintages of October 2008 to July 2018 due to the change in forecast process. Again, the percent error was calculated for the first forecast year, the second forecast year, and so on. The result was that one year out Xcel's average error equals 2.1 percent. Three years out Xcel's average error is about 3.6 percent. By five years out Xcel's average error is 7.1 percent. By seven years out Xcel's average error is 11 percent. This data indicates that the ± five percent forecast bands previously used by the Department in MP's case are not large enough to address the errors present in Xcel's demand forecast process once the forecast goes beyond about five years.

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[18] The importance of October 2008 forecast was explained by Xcel in response to Department IR No. 66 as:

> The Company notes that there are structural drivers – both relative to our forecasting methods and to our external operating environment – that may contribute to variation across the fifteen years of forecast vintages. For example, prior to October 2008, we did not reduce our forecasts for demand side management and energy efficiency effects. There can also be local economic conditions that drive unforeseen changes in demand and load between forecast vintages, such as the effect of recessions, or individual large customers exiting our service area.

Thus, in October 2008 Xcel changed its forecast process.

Table 4a: Xcel's Demand Forecast Error, Pre-October 2008 (percent)

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Forecast Vintage	**Aug-03**	5.9%	2.8%	-3.2%	3.1%	14.6%	17.7%	13.1%	9.2%	12.9%	14.0%	24.8%	30.2%	26.6%	35.3%	31.0%
	Jun-04	5.4%	2.2%	-3.8%	2.0%	13.2%	16.0%	11.3%	7.4%	10.9%	11.9%	22.3%	27.5%	24.1%	32.5%	28.5%
	Feb-05		0.7%	-4.6%	1.3%	12.7%	15.9%	11.3%	7.5%	11.1%	12.2%	22.7%	28.2%	25.0%	33.8%	29.8%
	Mar-06			-5.3%	1.2%	12.7%	16.6%	12.3%	8.7%	12.5%	14.0%	25.0%	30.7%	27.4%	36.8%	32.9%
	Sep-06			-5.1%	1.6%	12.9%	16.5%	12.0%	8.4%	12.2%	13.7%	24.6%	30.3%	27.0%	36.5%	32.6%
	Mar-07				1.1%	12.7%	15.5%	11.3%	7.6%	11.3%	12.2%	22.8%	27.9%	24.5%	32.8%	29.0%
	Oct-07				-0.5%	12.0%	14.8%	10.2%	5.9%	8.8%	9.3%	19.0%	23.4%	19.4%	26.9%	22.5%
	Mar-08					11.2%	14.4%	9.4%	4.9%	7.9%	8.6%	18.2%	22.6%	18.7%	26.3%	21.7%

Table 4b: Xcel's Demand Forecast Error, October 2008 to Present (percent)

Forecast Vintage	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Oct-08					10.0%	12.2%	6.7%	2.0%	4.8%	5.3%	14.5%	18.6%	14.7%	21.8%	17.3%
Apr-09						9.2%	3.1%	-1.7%	0.3%	0.4%	8.6%	12.1%	8.1%	14.5%	9.9%
Oct-09						0.1%	1.6%	-2.4%	0.3%	0.3%	8.4%	11.7%	7.5%	13.6%	8.9%
Apr-10							0.2%	-3.0%	0.3%	1.5%	11.0%	15.4%	12.0%	19.3%	15.3%
Jul-10							0.6%	-2.8%	0.4%	1.0%	10.1%	14.0%	10.1%	16.9%	12.4%
Apr-11								-5.0%	-2.4%	-2.4%	6.4%	10.5%	7.0%	13.8%	9.6%
Sep-11								1.8%	-2.8%	-3.3%	5.1%	9.0%	5.4%	12.0%	8.0%
Mar-12									-5.4%	-5.4%	2.7%	6.4%	2.9%	9.5%	5.6%
Jul-12									0.0%	-3.2%	4.9%	8.7%	4.9%	11.4%	7.2%
Mar-13										-3.7%	4.0%	7.5%	3.6%	10.0%	5.9%
Jul-13										-2.4%	5.7%	9.4%	5.5%	11.8%	7.3%
Sep-13										-3.7%	4.1%	7.2%	3.5%	10.0%	5.9%
Mar-14											5.0%	8.2%	4.4%	10.7%	6.6%
Aug-14											0.0%	7.9%	4.5%	10.9%	6.7%
Mar-15												7.2%	4.0%	10.5%	6.2%
Jul-15												6.6%	3.6%	10.0%	5.8%
Mar-16													1.5%	8.1%	3.6%
Aug-16													1.3%	7.4%	3.0%
Nov-16														7.4%	2.9%
Mar-17														7.5%	2.8%
Jul-17														6.9%	2.9%
Mar-18															1.3%
Jul-18															2.0%

To determine a forecast adjustment the Department compared the average error from Xcel's forecasts performed in October 2008 to July 2018 and determined a forecast adjustment considering Xcel's average error. The Department's demand forecast adjustment is shown in Table 5 below.

Table 5: Demand Forecast Adjustment (percent)

Forecast Year	Average Forecast Error	Department Forecast Adjustment	Difference
1	2.1%	2.0%	-0.1%
2	2.8%	2.0%	-0.8%
3	3.6%	4.0%	0.4%
4	4.9%	4.0%	-0.9%
5	7.1%	8.0%	0.9%
6	8.7%	8.0%	-0.7%
7	11.0%	12.0%	1.0%
8	12.6%	12.0%	-0.6%
9	14.1%	12.0%	-2.1%
10	13.5%	12.0%	-1.5%
11	17.3%	12.0%	-5.3%
12		12.0%	
13		12.0%	
14		12.0%	
15		12.0%	

Considering the poor quality of Xcel's forecasts, the Department did not want to imply that finely tuned adjustments were possible. Thus, the Department constructed the forecast adjustments using two criteria; maintaining any adjustment for two years and adjusting Xcel's forecast using two percentage point increments. For informational purposes, Table 5 above shows how the Department's forecast adjustment deviated from each year's average forecast error.

To determine forecast bands, the Department assumed that Company's forecast represents a reasonable high end of a forecast band. The Company's base forecast was used as the high contingency to create a tie between the forecast used by the Department and the forecast used by Xcel. For the low forecast band, the Department assumed the low forecast band used in the past, minus 5 percent, would remain sufficient.

As noted above Xcel changed its forecast process in October 2008. Thus, the Department's fourth step was to compare the two forecast processes. The Department compared the demand forecast errors for the two processes 1 year out, 2 years out, 3 years out, and so on. The Department based this comparison on the average error for Xcel's demand forecasts before October 2008 compared to Xcel's demand forecasts prepared in October 2008 and after, as shown in Tables 5a and 5b above. The Department's comparison showed that the original process had smaller errors (by about 0.4 percent) 1 year out. However, for years 2 through 9 the new forecast process had smaller errors (between 2 and 5 percentage points). In the last years (10 and 11)[19] the new forecast process had smaller errors (by about 9 percentage points) but there are very few data points to compare, rendering the comparison somewhat suspect. However, the new process did not eliminate the forecast bias which is the over-riding problem.

4. Energy Forecast Process

The Department repeated the analysis of Xcel's demand forecast process for Xcel's energy forecast process. Although the Department found that the Company's energy forecasting was less systematically biased than the demand forecasts, Xcel's energy forecast process is still systematically biased. Note that not all energy forecast vintages forecasted the same years as the equivalent demand forecast vintages and, as a result, the tables below are slightly different than the equivalent demand forecast tables. For example, the July 2018 forecast forecasted peak demand in 2018 but did not forecast energy in 2018.

The Department began the analysis of Xcel's past energy forecasts by calculating the difference between the forecasted and actual energy in GWh. The GWh error was then converted into a percent error. The results of this calculation are shown below in Tables 6a and 6b. In Tables 6a and 6b above, a positive number indicates the energy forecast turned out to be too high and a negative number indicates that the energy forecast turned out to be too low. For easy identification, the Department shaded cells in Tables 6a and 6b that are negative.

[19] Year 11 is the final year because the forecasts start in 2008 and the last year of actuals is 2018.

Table 6a: Xcel's Energy Forecast Error, Pre-October 2008 (Percent)

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Forecast Vintage	**Aug-2003**	6.1%	3.3%	2.8%	1.4%	4.8%	11.2%	10.6%	13.1%	16.8%	20.3%	22.8%	27.1%	28.1%	33.2%	31.3%
	Jun-2004	4.8%	2.2%	1.7%	0.2%	3.3%	9.1%	8.2%	10.4%	14.1%	17.1%	19.5%	23.6%	24.7%	29.6%	28.1%
	Feb-2005		2.2%	1.2%	-0.5%	2.7%	8.4%	7.4%	9.3%	12.7%	15.3%	17.4%	21.2%	22.2%	26.7%	24.9%
	Mar-2006			2.6%	1.3%	5.3%	12.2%	11.7%	14.4%	18.2%	21.9%	24.8%	29.6%	30.9%	36.6%	35.4%
	Sep-2006			3.7%	1.8%	5.3%	11.7%	11.0%	13.7%	17.4%	21.2%	24.1%	28.9%	30.1%	35.9%	34.7%
	Mar-2007				0.0%	2.4%	8.0%	6.7%	8.4%	11.2%	13.7%	15.2%	18.4%	18.5%	22.7%	20.7%
	Oct-2007				-0.1%	2.6%	8.1%	6.8%	8.4%	11.2%	13.6%	15.0%	18.1%	18.2%	22.1%	19.8%
	Mar-2008					1.3%	6.8%	4.8%	5.9%	8.5%	10.8%	12.1%	15.1%	15.0%	18.7%	16.3%

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Table 6b: Xcel's Energy Forecast Error, October 2008 to Present (Percent)

Forecast Vintage	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Oct-2008					0.1%	4.5%	2.3%	3.4%	5.7%	7.7%	8.8%	11.5%	11.3%	14.7%	12.3%
Apr-2009						4.1%	1.0%	2.2%	4.6%	6.7%	8.0%	10.8%	10.7%	14.2%	12.0%
Oct-2009						1.7%	-1.4%	0.5%	3.4%	5.8%	7.1%	9.6%	9.4%	12.9%	10.8%
Apr-2010							-1.7%	-0.2%	2.6%	4.6%	6.0%	8.5%	8.5%	11.7%	9.4%
Jul-2010							-1.5%	-0.7%	1.9%	3.8%	5.3%	7.9%	8.0%	11.1%	8.8%
Apr-2011								-0.7%	1.6%	2.6%	3.9%	6.7%	6.7%	9.8%	7.3%
Sep-2011								-1.1%	0.2%	0.9%	1.9%	4.4%	4.2%	7.1%	4.7%
Mar-2012									-0.8%	-0.8%	-0.3%	1.8%	1.6%	4.5%	2.0%
Jul-2012									-1.2%	-1.7%	-1.3%	0.7%	0.5%	3.2%	0.8%
Mar-2013										-1.5%	-1.4%	0.5%	0.2%	2.8%	0.4%
Jul-2013										-1.5%	-1.4%	0.5%	0.2%	2.8%	0.4%
Sep-2013										-1.5%	-1.8%	-0.2%	-0.6%	1.9%	-0.5%
Mar-2014											-1.3%	0.3%	-0.4%	2.2%	-0.3%
Aug-2014											-0.6%	1.9%	1.8%	4.6%	2.2%
Mar-2015												2.4%	2.5%	5.2%	2.7%
Jul-2015												1.5%	1.5%	4.2%	1.8%
Mar-2016													0.7%	3.2%	0.2%
Aug-2016														1.8%	-1.4%
Nov-2016														1.7%	-1.4%
Mar-2017														1.7%	-1.4%
Jul-2017															-1.5%
Mar-2018															-2.7%
Jul-2018															

When considering all of Xcel's energy forecasts, about 86 percent of the data points are positive and only 14 percent are negative. When considering only Xcel's energy forecasts from October 2008 to present, about 75 percent of the data points are positive and 25 percent are negative. Based upon this data, while not quite as clear as with the demand forecast process, the Department concluded that, once again, there is evidence of a systematic bias in Xcel's energy forecast process. The Company's energy forecast is consistently too high.

While not shown, the size of the energy forecast error may also be of interest. The Department focused on the energy forecast error for the energy forecasts from October 2008 to July 2018; the error was calculated for the first forecast year, the second forecast year, and so on. The result of the calculation was that two years out the Xcel's average energy forecast error is about 65 GWh, which is not much considering the size of Xcel's system.[20] Four years out Xcel's average energy forecast error is about 1,100 GWh. By six years out Xcel's average energy forecast error is about 2,150 GWh and at eight years out Xcel's average energy forecast error is 4,200 GWh or equivalent to the energy output from nearly 1,000 MW of wind or 2,500 MW of solar. As with the demand forecast, the size of the error consistently grows the further into the future the calculations are taken. The Department explains its methodology for choosing energy forecast bands below.

As with the analysis of the demand forecast process, the Department focused on the forecast vintages from October 2008 to present due to Xcel's change in forecast process. Again, the Department calculated the percent error for the first forecast year, the second forecast year, and so on. The result was that two years out Xcel's average energy forecast error equals 0.1 percent, which is essentially no different than zero. Four years out Xcel's average energy forecast error is about 2.4 percent, somewhat less than the equivalent figure for the demand forecast. By six years out Xcel's average error is 4.9 percent, equal to the Department's widest (±5 percent) forecast band used in the past. By eight years out Xcel's average error is 9.5 percent.

To determine a forecast adjustment the Department reviewed the average error from forecasts performed between October 2008 and July 2018 and determined an adjustment using that error. This is shown in Table 7 below.

[20] Note that, for comparison, a 100 MW wind unit at a 50 percent capacity factor or a 250 MW solar unit at a 20 percent capacity factor would each produce about 440 GWh annually.

Table 7: Energy Forecast Adjustment (percent)

Forecast Year	Average Forecast Error	Forecast Adjustment	Difference
1	-0.1%	0.0%	0.1%
2	0.1%	0.0%	-0.1%
3	1.4%	2.0%	0.6%
4	2.4%	2.0%	-0.4%
5	3.7%	4.0%	0.3%
6	4.9%	4.0%	-0.9%
7	7.3%	8.0%	0.7%
8	9.5%	8.0%	-1.5%
9	11.3%	10.0%	-1.3%
10	12.5%	10.0%	-2.5%
11	12.3%	10.0%	-2.3%
12		10.0%	
13		10.0%	
14		10.0%	
15		10.0%	

As noted previously, the Department used two-year intervals and two percentage point increments to calculate the forecast adjustment. To determine forecast bands, the Department assumed that Company's forecast represents a reasonable high end of a forecast band. The Company's base forecast was used as the high contingency to create a tie between the forecast used by the Department and the forecast used by Xcel. For the low forecast band, the Department assumed the low forecast band used in the past, minus five percent, would remain sufficient.

Finally, as noted above, the Company's forecast process changed in October 2008. Thus, the Department compared the energy forecast errors for the two processes—one year out, two years out, three years out, and so on. This was done based on the average error for Xcel's demand forecasts before October 2008 compared to Xcel's demand forecasts prepared in October 2008 and after. The result of the comparison was that the new process appeared to have lesser errors. However, the new process did not eliminate the forecast bias which is the over-riding problem.

5. Conclusion

The main conclusion from our analysis is that Xcel's demand and energy forecast processes are systematically biased; they produce forecasts that are too high much more often than they produce forecasts that are too low. Again, the Department notes, if there is a systematic bias that results in over-forecasting, the need for additional resources will be overstated. The resulting risk is that Xcel builds unnecessary resources resulting in potential cost-related risks to Xcel's customers. Clearly it would be preferable to have forecasts that appear to be unbiased, however such data is not available. To account for the persistent bias while allowing the remaining analysis to move forward, the base forecast was adjusted by the amounts shown in the Tables above. The

Department used Xcel's base forecast as the high end of the reasonable forecast band to create a connection between the Department's and Xcel's forecast used in modeling. The low end of a reasonable forecast is about five percent below the Department's base forecast.

To address the persistent bias in Xcel's forecast process going forward, the Department recommends that the Commission require Xcel to file and use a forecast from an independent consultant in any future regulatory proceedings. This requirement will enable Xcel's proceedings to continue normally while the Company attempts to audit and identify the flaws in their current forecast process. The use of an independently prepared forecast should continue until such time as Xcel can demonstrate in a separate proceeding that the Company has identified the source(s) of the bias in Company prepared forecasts and has identified, explained, and taken steps that can reasonably be expected to address the identified issues.

D. NATURAL GAS TRANSPORTATION RISKS

For this IRP the Department further explored the Company's exposure to risks related to natural gas transportation. This review was triggered by the increasing use of natural gas-fueled capacity on the Company's system and events during recent winters. Note that risks related to natural gas pricing are explored in the Department's CEM analysis elsewhere in these comments. The focus of this discussion is on the reliability of natural gas delivery to the relevant power plants.

In Department IRs Nos. 12 and 40 the Department requested Xcel provide certain data for each power plant that consumed natural gas during 2016 to 2018. Xcel's response provided data regarding several power plants, some of which use natural gas as a secondary fuel.[21] In addition, several of the units were reported by Xcel as having fuel oil as back-up.[22] These units and the Company's now retired units were removed from further analysis.

The remaining units which use natural gas with no fuel oil back up are forecasted to provide Xcel between 2.9 GW and 3.4 GW of accredited capacity during the years 2020 to 2030. While some units are scheduled to retire or have PPAs that expire, Xcel also expects the addition of a natural gas CC unit at the Sherco site.[23] Overall, about 60 to 67 percent of the expected natural gas capacity comes from six CC units[24] and a further 18 to 20 percent from four large CT units.[25] With the exception of the Blue Lake plant, the units all take firm service from an interstate pipeline (Northern Natural Gas) and, where applicable, firm transportation service from the local distribution company (LDC).

Regarding Blue Lake, Xcel's response to Department IR No. 40 stated:

> Blue Lake takes Firm Transportation service from the LDC system, because it was required to commit to such service to reimburse the LDC for constructing the supply pipeline serving the plant. Blue Lake takes interruptible service from the

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[21] Note that Xcel did not provide data regarding the Cottage Grove CC unit since under the PPA the seller (LS Power) is responsible for providing its own gas supply and transportation.
[22] The units with fuel oil are Angus C. Anson units 2 and 3, Wheaton units 1 to 6, French Island units 3 and 4, Inver Hills units 1 to 6, Blue Lake units 1 to 4, Mankato (first PPA only), and Cannon Falls units 1 and 2.
[23] See Minnesota Session Laws, 2017 Regular Session, Chapter 5.
[24] Namely Black Dog, High Bridge, Riverside, Cottage Grove, Mankato (second PPA), and the presumed Sherburne County addition.
[25] Namely Anson unit 4, Blue Lake units 7 and 8, and Black Dog unit 6.

> Interstate Pipeline to reduce costs, although the plant does use some firm Interstate gas service in the peak summer months. In practice, Blue Lake has reliable fuel supply under these service parameters at the most economic option for our customers.

Given Xcel's gas transportation/delivery practices, the main risk that remains is that all of Xcel's plants ultimately draw their natural gas supplies using the same interstate pipeline—Northern Natural Gas (NNG). This is a risk which cannot be mitigated at this time. However, Xcel's response to Sierra Club IR No. 61 stated:

> It is unlikely multiple gas generators connected to the same pipeline would experience similar outage profiles during a disruption. The Company contracts for firm transportation service on upstream pipelines for many of its gas generation resources. Firm service can only be interrupted under a force majeure situation which is very rare. And for those plants that do not have firm natural gas transportation service, the Company typically has onsite backup fuel supplies available. Furthermore, natural gas pipelines are often supplied with gas from multiple sources or interconnections with other pipelines at various locations such that if a disruption limits supply from one area, supplies from another can be increased to fill the void.

Therefore, based on the Company's response above, it appears that even if something catastrophic were to happen to NNG's transportation system, Xcel expects that it would not significantly impact Xcel's generation capability.

Based upon the above data, the Department concludes that Xcel's practices regarding accessing natural gas supplies in the recent past reflect steps Xcel has taken to ensure availability of fuel to the larger units on the Company's system. Further, the Department did not discover any unknown risks that need to be reflected in the Department's CEMs.[26]

E. SPOT MARKET TREATMENT IN IRP

1. Historical Approach

Traditionally, in IRPs the Department has treated the Midcontinent Independent System Operator, Inc. (MISO) energy and capacity markets (Spot Markets) as an alternative. In other words, the MISO energy and capacity markets are another option for a utility to consider in meeting its demand and energy requirements. Using a well-defined Spot Market construct allows the Spot Market to contribute towards meeting the four objectives of low cost, reliable, low socioeconomic/environmental impact system that manages risk. For example:

- allowing Spot Market energy to be consumed allows MISO's energy market to help minimize system costs;
- CO_2 emissions are accounted for in the Spot Market energy price, thus directly putting emissions into the cost minimizing routine (thus addressing impact);

[26] Both Strategist and EnCompass are valid CEMs.

- preventing capacity purchases means the CEM plans to build a system to meets Xcel's reliability needs with no reliance on other parties; and
- regarding risk, the discussion below is a lengthy discussion of how the Spot Market impacts risks in the IRP.

In general, Spot Market LMPs can be somewhat volatile. For example, Spot Market LMPs at the Minnesota Hub for 2008 averaged $46.16 per MWh and the LMP was over $100 per MWh for 813 hours. The next year (2009) Spot Market LMPs fell about 50 percent, averaging $23.70 per MWh and exceeded $100 per MWh in only 61 hours—a decrease of over 90 percent. While Spot Market LMPs have remained somewhat stable in the decade since, there is no reason to expect such stability to continue for another 15 years, or through the duration of an IRP.

In addition to the economic risks, MISO's Spot Markets have potential design issues that could lead to reliability problems if they are over-used. While this issue is discussed further below, the important conclusion is that the Spot Markets do not provide price signals far enough in the future to trigger addition of new capacity in a timely manner. This means reliance on the Spot Markets comes with a reliability risk for MISO market participants that do not have a well-functioning IRP process.

From the alternatives perspective, based upon the economic and reliability risks, in the past the Department's IRP goal has been to use Spot Markets as a short-term bridge. For example, to address timing issues regarding when existing resources retire and when replacement resources come on-line. The expectation was that, in most years, Spot Market purchases and sales would generally offset each other over a longer duration. Occasionally there might be a spike in either net purchases or net sales, but such events are expected to be temporary as part of a bridge.

Currently, the amount of non-dispatchable resources on Xcel's system necessitate a more nuanced understanding of Spot Markets in IRPs. For example, in the Strategist model that Xcel submitted with the Petition included, among others, the following capacity in 2023:

- Nuclear 1,750 MW;
- Wind 3,850 MW;
- Hydro[27] 750 MW; and
- Solar 1,050 MW;
    - Total 7,400 MW.

Meanwhile, the Company's 2023 *peak* demand forecast is less than 6,000 MW in several months. Thus, the wind and nuclear capacity alone, if operating at full capacity, could easily exceed the Company's load in many hours. Essentially, Xcel sells the excess energy (above load) into the Spot Market. This indicates that the increase in non-dispatchable supply capacity has reached the point where an expectation that net activity (the difference between utility supply and utility demand) in the Spot Markets will be low most of the time is no longer reasonable. The rise in the importance of the Spot Markets to balance the system in Xcel's IRP requires a more nuanced understanding of the actual interaction of the Spot Markets and Xcel's system.

[27] Some of the hydro resource may be dispatchable rather than run-of-river or confined to PPA terms, but given the overall facts—including the nature of the Company's PPAs with Manitoba Hydro—the Department elected to not attempt to separate out that dispatchable quantity.

2. *Spot Market Basics*

a. *Capacity Market*

At a simple level, the Spot Market construct involves two-steps. The first step is the capacity market. Broadly speaking, in the capacity market a utility has the choice between two different methods of participation. In the first method a utility may participate in the annual Planning Resource Auction (PRA). Essentially, utilities submit their resources with a bid price and MISO administratively determines the auction clearing price. Resources that participated and were selected by MISO receive the auction price. The utility then pays the auction clearing price for load. Note that there is no requirement that a participant in the PRA have both load and resources.

In the second method a utility may submit a Fixed Resource Adequacy Plan (FRAP). A utility that uses a FRAP designates resources to offset the utility's Planning Reserve Margin Requirement (PRMR)—the total load plus the reserve requirement. Load and resources used in a FRAP do not participate in the PRA.

In summary, under the first method the utility simply purchases generic capacity via MISO's PRA and under the second method the utility purchases capacity outside of the MISO process and demonstrates to MISO that it has purchased sufficient capacity.[28] Thus, in investment terms, purchasing capacity outside of MISO's PRA is simply the acquisition of a hedge against the PRA price.[29]

In hedging, one standard of comparison is what is referred to as a perfect hedge. A perfect hedge is a position that eliminates all risk associated with an existing position. In MISO, if a utility acquires capacity equal to its PRMR and submits the capacity and load to MISO in a FRAP, the utility has acquired a perfect hedge because the utility is not subject to the PRA price at all; there is no price risk associated with the utility's load.

Overall, as indicated above, utilities in LRZ 1 generally FRAP or self-schedule[30] their resources. In economic terms, one fundamental question for an IRP is "what is a reasonable price to pay for capacity as a hedge against price risk associated with merely submitting load to the PRA?" Or in rate recovery terms, is the price paid for a perfect hedge—a FRAP for the full PRMR—reasonable?

When considering this question, one must keep in mind that MISO's PRA process covers only a single year. Meanwhile, it can take several years for a new resource to come on-line. For example, the U.S. Energy Information Administration's *Assumptions to AEO2020* in the Electricity Market Module at table 3 shows a lead

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[28] The FRAP process is commonly used in Local Resource Zone (LRZ) 1. For the 2020/2021 PRA, LRZ 1 had a PRMR of 18,476 MW with 14,198.3 MW of FRAP and 3,800.1 MW of "self-scheduled" resources. For purposes of this docket, self-scheduling is very similar to a FRAP. Thus, for LRZ 1 about 76.8 percent of the PRMR was acquired via FRAP and nearly all of the remainder via self-scheduling. For MISO as a whole, the PRMR was 135,979.3 MW, with 46,320.2 MW of FRAP and 82,240.0 MW of self-scheduled resources. Thus, for MISO about 34.1 percent of the PRMR was acquired via FRAP and nearly all of the remainder via self-scheduling. See: https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf

[29] Hedging refers to buying one investment to reduce the risk of losses from another investment. Typically, an entity will buy an opposite investment to hedge. In MISO's capacity market process supply units and demand response are the opposite of load. Thus, the purchase of these capacity resources, which receive the PRA price, offsets the risk associated with load which pays the PRA price.

[30] For purposes of this proceeding, self-scheduling is similar to a FRAP, but for an individual resource rather than the utility's entire loads and resources.

time of two years for a combustion turbine and three years for a combined cycle unit. Thus, if a utility does not have sufficient resources to FRAP and prices in the PRA spike, upwards, then the utility may be paying the higher prices for an extended duration unless capacity can be found via a bilateral contract or constructed. However, if Spot Market prices are high, the price of the bilateral contract should also be high.

In this context it is important to note that prices in the PRA cannot go upwards past a certain boundary; PRA prices are limited to the cost of new entry (CONE). CONE is calculated within MISO's process based upon the cost associated with a constructing a new combustion turbine. Thus, the PRA price is capped at approximately the lowest cost of what would have to be done to cover load in any case. This built-in cap limits the financial risk associated with PRA participation and thus limits the hedging value of a FRAP. However, there are reliability consequences to PRA participation. If all utility load participated in the PRA with no utility resources submitted, PRA prices would go to CONE, which is not necessarily a financial problem since CONE is the cost that would be paid to build a new resource. However, there would be reliability issues associated with having insufficient resources in an LRZ and/or MISO as a whole.[31]

From this discussion it can be observed that, for MISO's capacity market to result in a reliable system, the individual states must engage in appropriate resource planning. This is because if all load decided to take advantage of the PRA prices—which cannot go higher than the cost of capacity that would otherwise be constructed, and most of the time will be lower—then insufficient resources would be available and reliability issues would follow.

b. Energy Market

The second step in the Spot Market construct involves the energy and ancillary services markets. MISO has both day-ahead and real-time energy markets and also ancillary services markets for functions such as regulation, spinning reserves, and supplemental reserves. For purposes of this discussion, these functions will all be treated as a single "energy" market.

Regarding participation in the Spot Market, the Commission's December 21, 2005 *Order Establishing Second Interim Accounting for MISO Day 2 Costs, Providing for Refunds, and Initiating Investigation* (Docket Nos. E002/M-04-1970, et al) required that "Each petitioner shall limit its level of activity in the real-time market to five percent of total purchases for retail customers, or make real-time market activities subject to prudence review on an annual basis in the annual automatic adjustment of charges docket arising pursuant to Minnesota Rules part 7825.2810." Further, the Company's May 1, 2020 *Petition for Approval of the 2021 Fuel Forecast Monthly Fuel Cost Charges* (Docket No. E002/AA-20-417) stated that the Company's:

> real-time market strategy currently is **[TRADE SECRET DATA HAS BEEN EXCISED].** The Company believes that this strategy meets the intent of the Commission's Order in Docket No. E002/M-04-1970 **[TRADE SECRET DATA HAS BEEN EXCISED]**.

In general, each location in MISO has its own Locational Marginal Price (LMP). The utility's load is bid into the energy market and the utility pays the LMP at the load's site. The utility's generation, if any, is also bid into the energy market and the utility receives the LMPs at the generator(s) site—if the generator(s) produce electricity.

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[31] It is possible for resources not under contract to be submitted into the PRA process by independent power producers. However, such resources are not large enough to serve all of the load in MISO.

In this scenario, Equation 1 provides a simple explanation of how the utility's overall energy bill is determined. For now, assume that the generator is always selected by MISO and produces energy equal to load.

Equation 1: Customer Bill Components

$$Variable\ Cost_{Gen} - LMP_{Gen} + LMP_{Load} = Utility\ Bill$$

From Equation 1 it can be seen that if Equation 2 is true:

Equation 2: LMPs are Equal

$$LMP_{Gen} = LMP_{Load}$$

then Equation 3 must be true as well:

Equation 3: Determining the Bill

$$Variable\ Cost_{Gen} = Utility\ Bill.$$

This example shows that, at one extreme, ownership of generation that produces energy equal to load each hour represents a perfect hedge against LMP risk in the Spot Market.

This example also implies that, in the other extreme where a utility does not own any generation, then the LMP_{Gen} and Variable $Cost_{Gen}$ are zero. From Equation 1 it can be seen that, in this scenario, the utility's bill is equal to LMP_{Load}. This represents a viable strategy that could be followed—not building generation and simply paying the Spot Market price. In essence, the utility would have no hedge.

Thus, acquisition of resources, to the extent they can produce energy that offsets load, represents another hedge, this time against Spot Market LMPs. Thus, *when resources are offsetting load, they represent a decrease in spot market risk.* Note that LMPs are not the same in all locations. The closer LMP_{Gen} is to LMP_{Load} the more successful a hedge the resources represent. If Equation 2 is true, then the resources represent a form of a perfect hedge. Assuming a successful hedge leads us to Equation 3 and the fact that the Variable $Cost_{Gen}$ determines the utility bill; the utility is insulated from Spot Market LMPs.

Note that in this case the acquisition of resources, while it insures against the risk inherent in LMP_{Load} it also creates risk in that Variable $Cost_{Gen}$ is uncertain. This is the case when variable costs are not known; for example, when a power plant is fueled by natural gas. In this example the acquisition of a resource as a hedge against LMP_{Load} leads to a different form of risk and another potential round of hedging—here against fuel price risk. Finally, while resources such as wind have little to no fuel cost risk, they are not completely dispatchable and thus cannot be assumed to be producing energy when LMPs spike upwards.

Also, when acquiring resources, it is not only the energy prices (expected LMP_{Gen} and LMP_{Load}) that must be considered but also the quantity (MW). The closer the MW of resources acquired is to the MW of load, the more successful a hedge the resources represent. When the MW of resources acquired are less than the MW of load, some of the load is unhedged and will pay LMP_{Load}. When the MW of resources acquired is greater than the MW of load, all of the load is hedged and, in addition, some of the resources represent speculation on LMP_{Gen}. Thus, *when resources greater than load are acquired, the resource represents an addition to the pool of spot market risk.* Since Xcel has resources far in excess of load, many of the resource additions are not a hedge <u>decreasing risk</u>. Instead they represent an increase in risk faced by Xcel's ratepayers.

There is a fundamental difference in the risk profile associated with resources acquired to offset load versus resources acquired based on expected LMP_{Gen}. During resource planning and resource acquisition, the reasons for acquiring a resource should be ascertained so that prudent decisions can be made by the Commission.

Furthermore, when acquiring resources the variable cost must be considered. At any point in time Variable $Cost_{Gen}$ can be less than, equal to, or greater than LMP_{Gen}. The analysis above dealt with the situation where Variable $Cost_{Gen}$ is equal to LMP_{Gen}. In a situation where the Variable $Cost_{Gen}$ is not equal to the LMP_{Gen}, then Equation 1 can be re-arranged to better show the consequences; see Equation 4 below.

Equation 4: Customer Bill Components Rearranged

$$LMP_{Load} - (LMP_{Gen} - Variable\ Cost_{Gen}) = Utility\ Bill$$

If Variable $Cost_{Gen}$ is less than the LMP_{Gen}, then the difference between LMP_{Gen} and Variable $Cost_{Gen}$ becomes a subtraction from LMP_{Load}, decreasing the utility bill. In this circumstance, ownership of generation is an advantage. If Variable $Cost_{Gen}$ is greater than LMP_{Gen}, then the generator should not operate.[32] In this circumstance, ownership of generation is a disadvantage. Thus, Variable $Cost_{Gen}$ represents a cap on exposure to LMPs because if LMP_{Gen} goes above Variable $Cost_{Gen}$, the utility's resource should provide energy in place of the Spot Market.

Finally, operational availability must be considered. A resource that is perfectly flexible—can be ramped up and down at will—represents the ideal resource from a hedging perspective because it lacks limitations on the ability to provide the hedge. However, no resource is perfectly flexible; for example, resources have a time lag between first being notified of the need to be on-line and operating at full capacity. Some resources, such as combustion turbines, are relatively flexible while others, such as nuclear units, are relatively inflexible. Finally, intermittent resources such as wind have limits in that availability of the fuel (wind) can be uncertain.

3. Spot Market and CEMs

The various factors involved in Spot Markets are considered in the CEMs to varying degrees. For example, Xcel has a Spot Market for capacity built into Strategist. Xcel's capacity market construct in Strategist allows sales (but not purchases) by Xcel of up to 500 MW. Sales are priced at the capacity cost of a generic combustion turbine (essentially at CONE). Because of the lack of purchases, the structure of inputs ensures that the Company plans to have sufficient capacity to meet the PRMR (mimicking the FRAP process); the construct does not assume that capacity will be available in MISO's PRA. While Xcel's pricing for sales is too high—Xcel assumes CONE is the Spot Market price which is rarely true—the difference between Xcel's assumed price and actual Spot Market prices should not have a significant impact on the timing of capacity additions.[33]

While the capacity market construct allows only sales, Xcel's energy market construct allows both sales and purchases. The energy market limit is 1,800 MW for any one hour during 2020-2023, which increases to 2,300

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[32] However, if the generator does operate despite the LMPs the difference between LMP_{Gen} and Variable $Cost_{Gen}$ becomes an addition to LMP_{Load}, increasing the bill. See Docket No. E999/CI-19-704 for further details.

[33] For example, Table 10 of Appendix F2 of the Petition assumes a $4.81 per kW-month price in 2020 (which is about $5.7 million for 100 MW for a year) while MISO's PRA capacity price was $5.00 per MW-day for 2020-2021 (which is about $0.2 million for 100 MW for a year). While large, based upon the Department's modeling results, the $5.5 million difference was too small to impact Strategist's results in a meaningful manner. At most the pricing might shift the in-service date of a capacity unit forward by a year or two, which is within the model's typical margin of error.

MW after 2023.[34] Thus, there are limits to how much the Company can rely upon the Spot Market. The policy question is how much reliance is reasonable. The higher the energy market limit the more the market can serve to reduce costs. But, the tradeoff is the same higher limit can create risks. For example, risk could be added via adding units to make profitable sales, only to find out later that the energy market pricing was wrong and the unit's costs are incurred, but the offsetting market revenues are not realized.

Finally, the Department notes that all Spot Market constructs in CEMs contain an inherent flaw that must be considered when analyzing and interpreting CEM outputs. In economic terms, CEMs contain barriers to entry that prevent utilities, other than the utility being modeled, from responding to any price signals contained in the CEM. For example, it could be the case that new solar units are priced at $8 per MWh while the Spot Market price is set at $10 per MWh in a CEM. In this circumstance, the CEM would add solar to sell into the Spot Market and reduce overall system revenue requirements by the $2 per MWh gap. However, in the real world, responding to the $2 gap between solar prices and Spot Market prices is not limited to the utility being modeled. Other utilities (such as Great River Energy), independent power producers (such as NextEra Energy, Inc.), and others can also respond to the gap. The resulting competition would eliminate the $2 per MWh gap. Thus, the CEM's expected profits may not be realized in the real world. The consequence of this for Xcel's IRP is that units that are added by the CEM may only be added due to the difference in their cost versus the expected Spot Market revenue. That difference might not be realized when entities other than Xcel respond to the price signal.

The same logic applies to existing units, not just new units. For example, assume that that a CEM has a single natural gas price for all units to use and that the CEM's Spot Market prices were designed using that natural gas price and a CT unit (with a heat rate of 10,000 MBTU per MWh) to set the Spot Market price. If the utility being modeled has a CC unit (with a heat rate of 7,000 MBTU per MWh) then that CC unit will be able to take advantage of the heat rate differential (the 3,000 MBTU per MWh gap between the Spot Market's CT and its own heat rate) to sell energy into the Spot Market and reduce overall system revenue requirements by the 3,000 MBTU per MWh gap. Once again, in the real world, responding to the heat rate gap between CC units and Spot Market prices is not limited to the utility being modeled. Other utilities, independent power producers, and others can also respond to the gap. The resulting competition would eliminate the heat rate gap. Again, the CEM's expected profits may disappear in the real world.

In summary, CEM's are a static model of a dynamic process. As a result, it is not enough to simply get a set of results. It is critical to understand why the model is producing the results and to understand the resulting risks from factors outside the model's consideration. The result for the IRP is that units recommended for the Xcel's expansion plan may differ from CEM outcomes due to the necessity of considering factors beyond the CEM's ability to consider. In particular, units may be removed from the proposed expansion plan if it appears they are cost effective largely due to an assumed gap between the unit's costs and the expected revenues from the Spot Market.

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[34] The increase is based upon anticipated in service of the Cardinal—Hickory Creek 345 kV transmission line which is expected to increase transmission outlet in the region. For further information on this project see https://www.cardinal-hickorycreek.com/.

4. Conclusions on Spot Markets in Xcel's IRP

Overall, Xcel has included Spot Markets in the Company's CEMs and has placed limits on the Spot Markets. The capacity market construct used by Xcel mimics the FRAP process (capacity hedging) and serves to limit the Company's exposure to reliability risks, while somewhat over-valuing excess capacity. For modeling purposes, while the capacity price is unlikely to impact the overall plan, the Department reduced the price for excess capacity. See the Strategist Modeling section below for further details.

The energy market construct used by Xcel allows the Company to purchase and sell significant quantities of energy, thus building into the IRP the potential for the Company to become overly reliant on the Spot Market as a source for energy or as a sink for surplus energy. In addition, the limits of the EnCompass and Strategist model inputs means that only Xcel's system can respond to price signals. If the inputs can create the appearance of the opportunity for Spot Market profits, the model will respond by adding units to Xcel's system. This creates a risk that the model will add units to profit on the Spot Market prices that will not be realized as in the real world all market participants react. Thus, the profits may not be realized in the real world. Thus, in the Strategist Modeling, the Department did not change Xcel's Spot Market inputs. Based upon concerns regarding unrealizable Spot Market profits, the Department reviewed the generation of various units to see if they had an unusually high capacity factor—a sign of problematic interaction with the Spot Market. Finally, the Department ran a contingency on each scenario that turned the Spot Market off. The purpose was to see how the Spot Market construct contributed to the overall plan.

F. RELIABILITY VERSUS ECONOMIC RISKS

Xcel confuses economic and reliability risks in the Company's presentation of its analysis. Specifically, in the Supplement's Attachment A, at page 11 of 176 Xcel stated:

> In our initial Plan, we discussed the need for a Reliability Requirement, that would maintain sufficient firm dispatchable capacity on our system over the long term, in order to meet customers' energy needs in every hour of every day. This Requirement was derived based on real-world operating conditions: we have, in fact, already encountered days when wind and solar are not available and, but for dispatchable generation on our system, customers' expectations of reliability would not have been met.

Later, Xcel makes a similar statement "we have modeled an unconstrained system in Strategist and EnCompass capacity expansion functionality, and then we used EnCompass 8,760-hour chronological modeling to determine our Preferred Plan's reliability risk exposure under low renewable availability conditions." Xcel's statements are incorrect because, regardless of the availability of dispatchable generation on Xcel's system, the Company's load (and customer reliability expectations) would still be met, only by non-Xcel generation obtained via participating in the broader MISO market. Lack of dispatchable capacity on Xcel's system is not a reliability issue because the load simply would be met by non-Xcel resources—in other words Xcel becomes a net importer in certain hours.[35] Instead, it is an economic risk (hedging) issue. As explained above, to the extent Xcel is a net importer the Company pays the Spot Market price for energy and thus is exposed to an unhedged economic risk.

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[35] The only exception is that enough resources must be located in each local resource zone to meet a portion of the load in that zone. Xcel could reasonably claim that a portion of the quantity resources that must be sited locally need to be on the Company's system for planning purposes.

In comparison, insufficient dispatchable capacity on MISO's system as a whole during low wind/solar output hours could be a reliability issue as it might result in a situation where insufficient capacity was available to MISO to dispatch in order to meet load. This is a system-wide reliability issue. A regional reliability issue could occur if Xcel's shortfall exceeded the region's import capability available from the rest of MISO (via the transmission system) and Xcel did not have sufficient firm capacity available to make-up for that shortfall. That is, a reliability issue would occur if Xcel's capacity deficit triggered a regional capacity deficit greater than the region's ability to import power.

Overall, Xcel's confusing economic risk (exposure to MISO spot market prices due to being a net importer) with reliability risk (insufficient capacity available system-wide or insufficient import capability to meet load) creates problems for parties in understanding the consequences of the Company's proposal. The Department recommends that Xcel take greater care to distinguish between economic risks and reliability in the future.

Also, Xcel's Petition identified a potential risk-related issue: "The addition of several gigawatts of renewable resources requires that we consider not only our traditional summer peak, but also whether we have sufficient dispatchable resources to meet other peaks, including in winter when solar energy is typically unavailable and wind resources may not be available for long periods of time." This is not a new issue for Xcel. On January 29, 2016 in Docket No. E002/RP-15-21 Xcel filed the Xcel's *Supplement to Xcel Energy's 2016-2030 Upper Midwest Resource Plan* (2016 Supplement). The 2016 Supplement discussed the need for dispatchable generation, typically combined with policy considerations that indicated some of the dispatchable generation should be near Xcel's North Dakota load. The 2016 Supplement stated, "With the high penetration of renewables on the NSP System, we must ensure that we have adequate dispatchable generation to both accommodate the load and whatever generation mix we have at each point in time." Examples of the need for dispatchable resources given by Xcel in the 2016 Supplement include providing spinning reserve, ensuring system reliability, providing grid support, and so forth.

The risk identified by Xcel in the Petition is similar to the risk identified by other utilities in recent years. For example, MP in the proceeding regarding MP's proposed Nemadji Trail Energy Center (Docket No. E015/AI-17-568) stated "The addition of a combined-cycle generation resource increases Minnesota Power's capability to bring generation on and offline quickly in order to manage energy imbalance, while providing regulation and load following, and to serve as an economic hedge for customers when the wind is not blowing and market prices are high." In addition, Otter Tail Power Company (OTP) in OTP's most recent IRP (Docket No. E017/RP-16-386) stated:

> Our new CT project [Astoria Station] will serve to hedge customers' energy needs, so that they are not paying high market prices during periods when the wind isn't blowing. In addition, it will afford us dispatch flexibility to serve as a price hedge for our customers at times of high energy prices.

To address the perceived risk of Xcel's preferred plan in the Petition, they included the addition of approximately 1,700 MW of firm dispatchable, load-supporting resources. In Strategist these units are modeled as natural gas combustion turbine (CT) units as a placeholder. The Petition defers these additions until the 2031 to 2034 timeframe, "in anticipation of technological advancements that will improve the functionality and drive down the cost of resources, like storage, that can take the place of traditional gas peaking units." Again, since resources are dispatched centrally by MISO to meet the total demand on the MISO system, neither Xcel nor any other utility on its own can have a need for dispatchable resources to meet the Company's load as claimed in the statements above. Instead, the Department views the issue of having "sufficient dispatchable resources to meet other peaks" as an issue of the potential need to hedge the exposure of ratepayers to Spot Market LMP risk.

Depending upon the degree to which the Commission determines to rely upon the ability of non-dispatchable resources to mitigate risk, the issue of Spot Market exposure may influence the mix of resources ultimately determined to be necessary to replace resources ordered to be retired as a result of this resource plan. If multiple coal and/or nuclear units retire by 2030, the ability of dispatchable units to hedge against market prices (while creating a fuel price risk) may or may not be necessary. The Department agrees with Xcel that no determination is necessary at this time because deferring the issue to the next IRP would still leave Xcel with sufficient time to acquire any dispatchable, peaking resources determined to be needed to hedge any identified risks in the early 2030s. In summary, the Department did not make any adjustments to the CEM based upon this spot market analysis.

Finally, the Department notes that Xcel, in evaluating potential plans, included a metric that added Spot Market imports with Spot Market exports to determine an overall Spot Market exposure. Such a metric confuses the differing risks associated with a position of being a net exporter or net importer in the Spot Market. The risks associated with Spot Market imports are generally the opposite of the risks associated with Spot Market exports. For example, an upward spike in Spot Market prices causes an increase in overall costs for a utility that is a net importer (during the price spike) but a decrease in overall costs for a utility that is a net exporter. It is not clear to the Department that adding the two risks creates an appropriate evaluation metric. Instead, since the risk are opposite, the Department would subtract the two to determine the net risk exposure of the various plans.

G. ASSESSMENT OF MISO IMPACTS

1. Introduction

In preparation for our CEM analysis the Department reviewed information regarding the current status of MISO's generation interconnection queue (GIQ). One potential issue regarding Xcel's preferred plan is the degree to which the plan can be implemented given that generation projects of any size must move through MISO's GIQ before they can come on-line. Distributed generation (DG) and load management projects can bypass the MISO GIQ. Thus, the GIQ cannot eliminate a preferred plan, but can limit the alternatives available to meet the preferred plan.[36] Both the issue of MISO GIQ status and the potential impact on generation units are explored below.

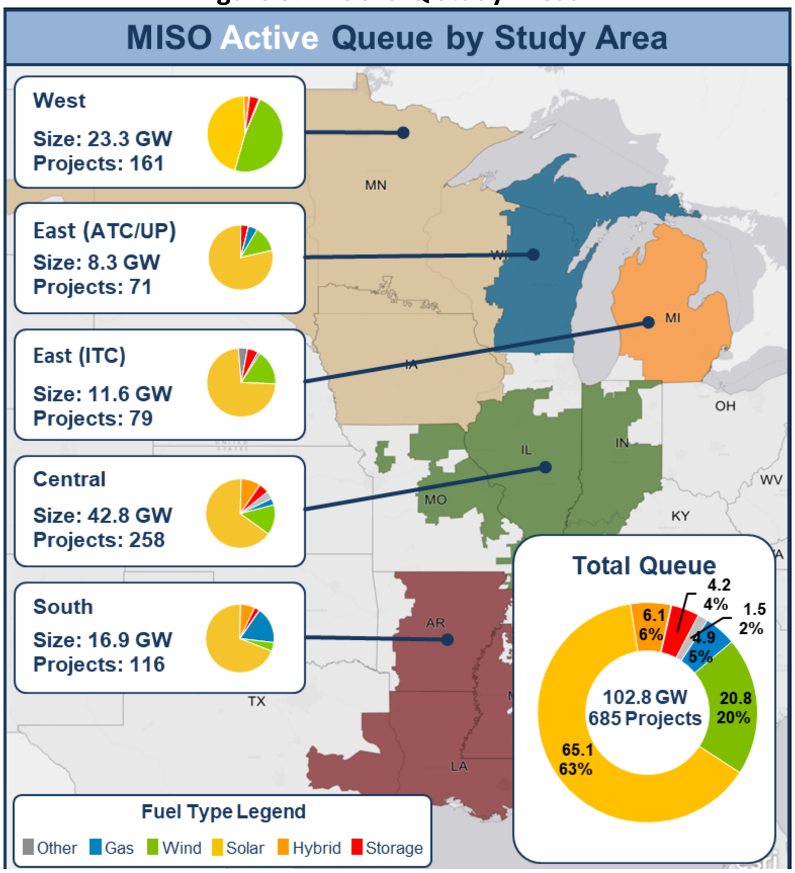
[36] For example, a 500 MW solar unit may have to be installed as separate projects too small to require studying in the GIQ process.

2. Status of MISO's GIQ

a. Background

The MISO GIQ is divided into several study areas. A picture of the GIQ study areas is provided in Figure 3 below. Figure 3 shows that Minnesota is in the West Study Area. Thus, all subsequent data in this section focuses on the West Study Area. Also note that Figure 3 shows that, as of December 1, 2020, a total of 102.8 GW in MISO as a whole and 23.3 GW for the West Study Area in the GIQ. For purposes of context, the MISO system peak demand would be approximately 125 GW. The GIQ's West Study Area appears to be similar to the MISO North region reported in MISO's *Daily Regional Forecast and Actual Load* report. For the years 2015 to 2019 the MISO North region's annual peak demand varied from 24.9 GW and 26.2 GW. Thus, the generation in the GIQ represents a sizable fraction of existing load for both MISO and the West Study Area.

Figure 3: MISO GIQ Study Areas[37]



Based upon this data and other factors MISO has concluded that many interconnection requests in the GIQ will never be built. In response, MISO has recently implemented GIQ reforms, such as increased site control requirements. The reforms are targeted at reducing the number of non-buildable projects in the GIQ. The degree of success realized by MISO's reforms will be determined in the future as the changes are implemented and market participants react to the changes.

b. Delay Issues

In March 2020 the Department obtained data from MISO's website regarding the initially announced and actual start dates for each Definitive Planning Phases (DPP) group that was currently underway and for the most recently completed DPP group. The data was updated again in January 2021. In obtaining this data the Department focused on the MISO West Study Area and did not go further back than April 2017. Therefore, the "initially announced" dates for some DPP groups are likely not far enough in the past. However, the data

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[37] Taken from the *Informational Forum* presentation available on MISO's website, dated December, 2020: https://cdn.misoenergy.org/202012%20Informational%20Forum%20Presentation505281.pdf

obtained is sufficient to illustrate the timing issues encountered by projects in MISO's GIQ process. This data on DPP start dates illustrates the delays encountered by MISO in getting a DPP group started.

The Department also obtained the estimated final date to execute[38] a generation interconnection agreement (GIA) when each DPP group started and the actual final date (or most recent estimate) for executing a GIA. This data on final date to execute a GIA illustrates the delays encountered by MISO in getting a DPP group from the start to the end; in other words, the delay in processing the group. The two sets of data are summarized below in Table 8.

Table 8: MISO West Study Area Group Start and End Dates

West Study Area Groups	DPP Start			GIA Executed			Total Delay
	First Estimate Announced	Actual	Delay Days	Estimate at DPP Start	Actual	Delay Days	
DPP-16-FEB	27-Jan-17	27-Jan-17	-	16-Jun-18	29-Mar-19	286	286
DPP-16-AUG	16-Jun-17	12-Sep-17	88	21-Feb-19	01-Mar-20	374	462
DPP-17-FEB	03-Nov-17	15-Oct-18	346	02-Mar-20	16-Mar-20	14	360
DPP-17-AUG	23-Mar-18	12-Jun-19	446	05-Nov-20	18-Nov-21†	378	824
DPP-18-APR	10-Aug-18	09-Sep-19	395	28-Jan-21	29-Nov-21†	305	700

† Indicates the current estimate for the date.

Table 8 shows that the recent study DPP groups in the West Study Area have all encountered substantial delays. The minimum delay encountered, for DPP-2016-FEB, is nine months. The maximum delay, for DPP-17-AUG, is about two years. Clearly the reforms implemented by MISO will require a dramatic impact to reduce the delays in processing the West Study Area GIQ to a reasonable level.[39]

According to the schedules obtained by the Department, the actual DPP process was supposed to take a total of approximately 510 days (~17 months). Again, MISO has been working to substantially reduce the time required for the DPP process. Nonetheless, the Department used this data to estimate the lead time to get through MISO GIQ. Considering the minimum overall delay of 9 months results in an estimate of at least two years to get through the MISO GIQ process. Considering the maximum overall delay of two years results in an estimate of about 3.5 years to get through the MISO GIQ process.

Assuming one or two years are needed for final permitting and construction of a project indicates that it would be wise to assume that no new supply units are available in a CEM for the first five years unless it is reasonable to assume that new projects:

- can be acquired in a manner that avoids the MISO GIQ process; or
- currently in the GIQ (or recently completed the GIQ without a buyer) can be obtained at a reasonable cost.

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[38] Executing a GIA is the final step in MISO's GIQ process.

[39] The Department notes that the initially announced start date for the DPP-2019-Cycle 1 group was December 20, 2019 and the current estimated start is May 5, 2020, a delay of 137 days. The initially announced start date for the DPP-2020-Cycle 1 group was December 3, 2020 and the current estimated start is January 6, 2021, a delay of only 34 days.

The transmission costs recently incurred by projects in the GIQ are discussed in the next section. Ultimately, the Department did not limit availability of new expansion units in the early years because they were rarely selected by Strategist and there is no reason at this time to limit resource planning based on MISO's GIQ since there are other potential paths to obtain projects. In the later years of this IRP the delays are not as important because there will be sufficient time to take the steps necessary to construct a new project.

c. Cost Issues

Table 9 below shows the capacity studied and the resulting costs from the published studies for all three DPP phases for the three most recently completed DPP groups in the West Study Area. While DPP1 results from the next group in the West area study (DPP-17-Aug) were available when the analysis was performed, they are not comparable to the data shown here due to changes in what is studied in DPP1.[40] DPP2 results for DPP-17-Aug became available later and showed costs, both maximum and average, four to six times the levels in DPP-16-FEB and DPP-16-AUG.

Table 9: MISO West Study Group Results

	MW			Average $,000 / MW			Maximum $,000 / MW		
Study Group	**DPP1**	**DPP2**	**DPP3**	**DPP1**	**DPP2**	**DPP3**	**DPP1**	**DPP2**	**DPP3**
DPP-16-FEB	5,690	4,871	4,686	$471	$147	$65	$1,164	$246	$159
DPP-16-AUG	5,618	2,550	2,302	$609	$130	$117	$1,923	$461	$134
DPP-17-FEB	3,421	1,394	245	$988	$1,511	$1,122	$2,089	$4,265	$1,211

To provide context for the cost numbers in Table 9, the U.S. Energy Information Administration's (EIA) *Assumptions to AEO2020* publication shows an estimated overnight cost to construct a wind project of about $1.3 million per MW. Note that of the approximately 14.7 GW covered by the three groups' DPP1 study, about 13.8 GW or 94 percent were wind.

Table 9 shows that the DPP-16-Feb group was largely successful in obtaining interconnection at a reasonable cost; 82 percent of the capacity studied in DPP1 was still in active for DPP3 and the maximum cost for a project turned out to be $159,000 per MW or a 12 percent increase using EIA's overnight wind cost. However, the second group in Table 9, DPP-16-AUG, encountered significant transmission cost issues and was less successful; only 41 percent of the capacity studied in DPP1 was still in active for DPP3 but the maximum cost for a project was similar, about $380,000 per MW or a 29 percent increase using EIA's overnight wind cost.[41] Finally, the third group in Table 9, DPP-17-FEB, largely failed; apparently due to transmission cost issues. Only seven percent of the capacity studied in DPP1 (two projects) was still in active for DPP3 and the maximum cost for a project soared to $1,211,000 per MW.[42]

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[40] The changes are part of MISO's efforts to speed up the DPP studies.

[41] This cost was for two projects sharing a point of interconnection just southeast of Bismarck, North Dakota. Excluding these two projects the maximum cost falls to $141,000 per MW, which is similar to the prior group.

[42] The Department understands that these two projects did not finish the MISO GIQ process.

From the data in Table 9 it appears that the affordability upper limit for a project is around $150,000 per MW for transmission costs, at least for wind projects. Further, the West Study Area appears to be out of affordable transmission interconnection capability. Since Xcel's preferred plan involves obtaining interconnection for substantial amounts of new capacity, it is not clear that the plan is achievable within the MISO GIQ construct. Furthermore, no amount of GIQ timing reforms can change the lack of transmission; it can only deliver the message that transmission is not available sooner. Therefore, it would appear that either substantial new transmission needs to be built or Xcel will be limited to pursuing projects that avoid the MISO GIQ.

3. Status of MISO Congestion

DG and load management may be able to avoid the transmission cost and GIQ delay issues discussed above. However, if lack of a study means a DG project avoids a finding that it contributes to congestion costs or avoids a finding that the DG actually requires new transmission, then other new projects that are studied will have to pick up the DG project's transmission costs and existing projects will incur the DG project's congestion consequences. For example, depending upon transmission topology, energy generated by a DG solar project may cause curtailment of a central station wind project, resulting in no net increase in renewable energy generation. In other words, Minnesota generally is part of an energy exporting region and has experienced significant limits on the amount of power that can be exported. While the concerns about curtailment generally involve wind resources, the fact is that all of the generation and load combined on the Minnesota side of the constraint contributes to the resulting congestion in Minnesota.

The Department reviewed two sources of data regarding congestion. The first was Xcel's curtailment data in the Company's *Annual Report* in Docket No. E999/AA-20-171; Part H, Section 5, Schedule 1 of the *Annual Report* contains a summary of wind production and curtailment payments. Figure 4 below shows the 12-month rolling average curtailment as a percentage of total wind output.

Figure 4: 12-month Rolling Average Wind Curtailment

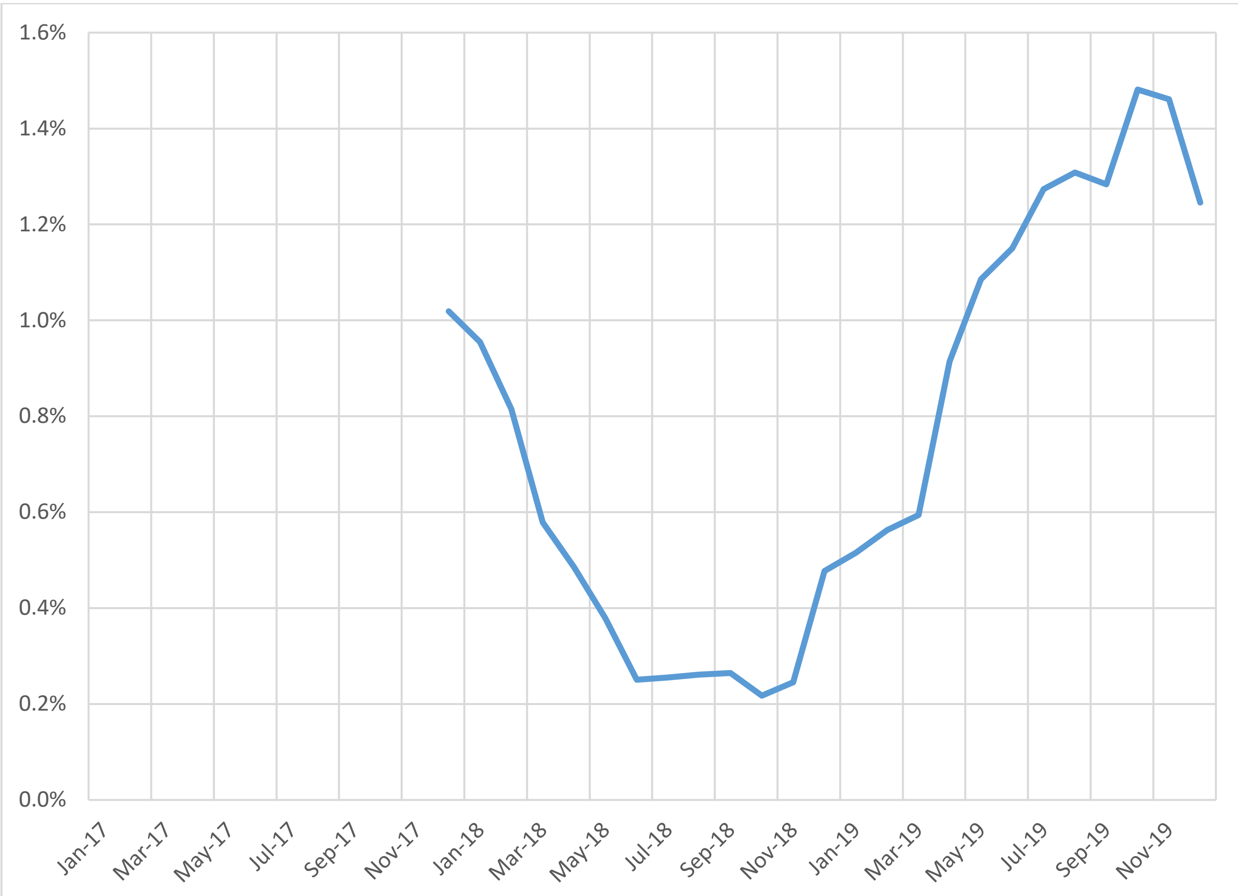

Figure 4 shows that the degree of curtailment, while still small, was consistently higher in 2019 than in prior years, leading to a continual increase in the rolling average. Thus, in 2019 there is some evidence that curtailment could become a significant issue in the future.

The second source of data regarding transmission congestion and the resulting curtailment was the marginal cost of congestion (MCC) component of the LMP. Figure 5 below shows the 365-day rolling average Real-time MCC for various hubs in MISO.

Figure 5: 365-day Rolling Average Real-time MCC

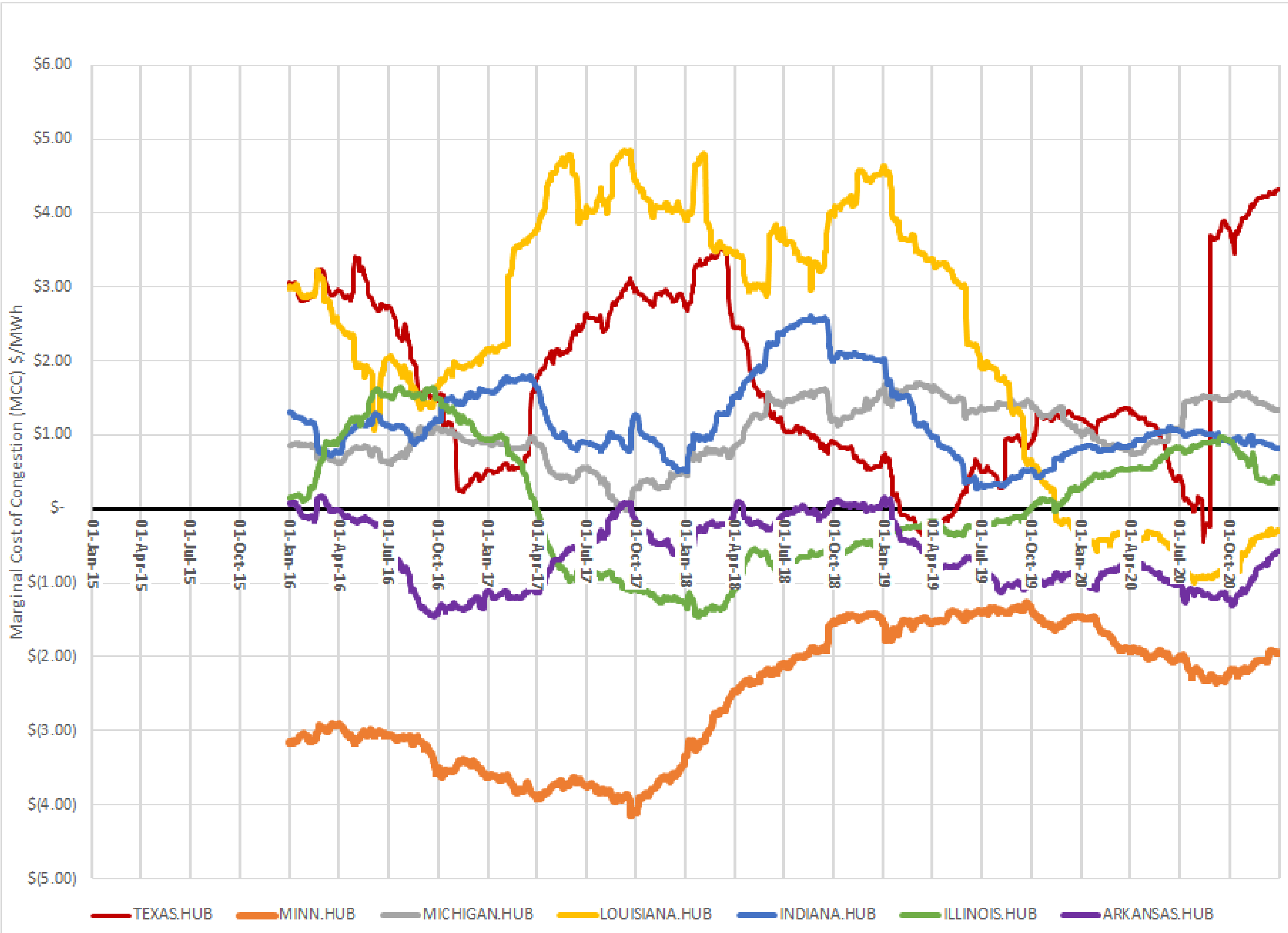

Figure 5 shows that throughout 2016 and 2017 the rolling average MCC was between $-3.00 and $-4.00 at the Minnesota hub. However, throughout 2018 the rolling average MCC moved to around $-1.50 and stayed at that level in 2019—indicating less congestion. The data for 2020 show the MCC moving back to around $-2.00 to $-2.25, indicating congestion is returning. The MCC data is consistent with the curtailment data in that both show the transmission system performance improving throughout 2018 but that improvement halted in 2019. Both sets of data point to a conclusion that additional transmission is likely to be needed if increases in curtailment in the next few years are to be avoided.

4. Recommendations Regarding MISO

The Department notes that under Minnesota Statutes § 216B.2425 all utilities that own or operate electric transmission facilities in Minnesota must file a report by November 1st of each odd numbered year on the status of the transmission system. In the *2019 Biennial Transmission Projects Report* filed by the Minnesota Transmission Owners (Docket No. E999/M-19-205) the Commission required additional information be provided on transmission improvements that may be needed to meet utility clean energy goals and resource plan requirements, and to identify any gaps that may exist. Therefore, the Commission is addressing any potential transmission shortfalls in the biennial transmission planning process.

Based upon the review in this section, it is unlikely that significant amounts of new resources can be added by Xcel in the near future unless the resources can be obtained outside of the MISO GIQ. In addition, the data indicates that a transmission cost cap of about $150,000 per MW currently exists. However, the data also show that there is little interconnection capacity with costs below the cap. Therefore, the Department concludes that either the transmission cost cap will increase, the cost of major transmission upgrades that increase interconnection capacity will be distributed beyond the GIQ (for example, as Market Efficiency Projects (MEP) or Multi-Value Projects (MVP)), or generation projects will not get built via the GIQ. Ultimately, the Department determined to leave Xcel's transmission costs for generic units in place as a compromise solution. Xcel's cost is above the $150,000 per MW cap but not reflective of the average cost per MW for the most recent study group in DPP1 and DPP2.

H. ASSESSMENT OF SHERCO CC UNIT

Minnesota Session Laws 2017, Regular Session, codified the following regarding the Sherco CC unit into statute, which states:

> Section 1. NATURAL GAS COMBINED CYCLE ELECTRIC GENERATION PLANT.
> (a) Notwithstanding Minnesota Statutes, section 216B.243 and Minnesota Statutes, chapter 216E, a public utility may, at its sole discretion, construct, own, and operate a natural gas combined cycle electric generation plant as the utility proposed to the Public Utilities Commission in docket number E-002/RP-15-21, or as revised by the utility and approved by the Public Utilities Commission in the latest resource plan filed after the effective date of this section, provided that the plant is located on property in Sherburne County, Minnesota, already owned by the public utility, and will be constructed after January 1, 2018.
>
> (b) Reasonable and prudently incurred costs and investments by a public utility under this section may be recovered pursuant to the provisions of Minnesota Statutes, section 216B.16.
>
> (c) No less than 20 months prior to the start of construction, a public utility intending to construct a plant under this section shall file with the commission an evaluation of the utility's forecasted costs prepared by an independent evaluator and may ask the commission to establish a sliding scale rate of return mechanism for this capital investment to provide an incentive for the utility to complete the project at or under the forecasted costs.

First, the Department interprets Section 1 (a) of the Sherco CC Statute as allowing Xcel to bypass the certificate of need (CN) process under Minnesota Statutes § 216B.243 for the generating unit and any associated transmission facilities.[43] In resource planning terms, this means that it is appropriate to treat the Sherco CC unit as an approved project in this proceeding. In CEM terms, that means the Sherco CC unit is locked into the Company's generation portfolio as of the expected in-service date. Notwithstanding this understanding, the

[43] Note that the Statutory bypass is limited to the generating unit proposal in Docket No. E002/RP-15-21 or that proposal as revised by Xcel (and approved by the Commission) in this proceeding. Xcel has not proposed or requested approval of a revision in this proceeding.

Department recognizes that hypothetical scenarios involving the Sherco CC unit can have resource planning value by providing information regarding, for example, the consequences of the Sherco CC unit being of a different size and/or timing or not being constructed at all.[44] The Department has performed such hypothetical scenarios on existing or committed units in past IRPs. In any event, unless stated otherwise the Department's CEM scenarios treat the Sherco CC unit the same as Xcel—as a "locked-in" addition to the supply mix in 2027.

Second, the Department notes that the Sherco CC Statute exempts a natural gas combined cycle electric generation plant from the certificate of need requirements of Minnesota Statutes § 216B.243 and site requirements of Minnesota Statutes § 216E. "Transmission lines directly associated with the plant that are necessary to interconnect the plant to the transmission system" are part of the definition of a large energy facility (see Minnesota Statutes § 216B.2421 subd. 2 and thus are considered as part of the generating unit. This means the interconnection transmission also is exempt from the CN/site permit requirements. However, natural gas pipelines are not bundled into the definition of the generating facility.[45] Thus, the Department concludes that, if Xcel intends to build a "pipeline for transporting natural or synthetic gas at pressures in excess of 200 pounds per square inch with more than 50 miles of its length in Minnesota," a CN and site permit would be required for the natural gas pipeline.

Third, the Department interprets Section 1 (b) of the Sherco CC Statute as generally maintaining the Commission's standard authority regarding rate recovery. This implies that the Company's investment in the Sherco CC unit is not risk free. The risk is that Xcel can only recover "reasonable and prudently incurred costs and investments." This immediately raises the question "when is a determination regarding reasonable and prudently incurred costs made?" Standard Commission practice is for such a determination to be made when Xcel requests recovery of the costs. This request would be made in a rate case following the Sherco CC unit being placed in-service. In this IRP proceeding since Xcel:

- has not made a cost recovery request;
- has not attempted to demonstrate the reasonableness and prudence of any Sherco CC-related costs; and
- has not even provided the Company's final cost estimates (see the Sherco CC Statute's Section 1 (c));

the Department recommends the Commission not make a determination regarding reasonable and prudently incurred costs in this proceeding. Since Xcel has not requested approval of a revision of the Sherco CC unit included in the last IRP, the Department also recommends the Commission not approve any revision to the Sherco CC unit included in E002/RP-15-21.

Fourth, the Department interprets Section 1 (c) of the Sherco CC Statute as creating a special, one-time process for addressing the Company's final, pre-construction cost estimates for the Sherco CC unit. The Sherco CC Statute specifically mentions establishing a sliding scale rate of return mechanism. It is likely that other issues related to the Sherco CC unit's costs will be raised by parties to that proceeding. In any event, until the Company's final, pre-construction cost estimates are available, definitive conclusions regarding the Sherco CC unit cannot be drawn.

[44] As discussed further below, the Department ran a Strategist Scenario without the Sherco CC unit to better analyze why the unit had a high capacity factor. See Attachment 3 for a summary of these modeling outputs.
[45] See Minnesota Statutes § 216B.2421 subd. 2 (1).

I. COMPARISON OF STRATEGIST AND ENCOMPASS

1. Introduction

Both Strategist and EnCompass are CEMs. CEMs simulate long term generation needs, given assumptions about future electricity demand and energy requirements, fuel prices, cost of various expansion alternatives, policy considerations, and so forth. In general, a CEM is best used for studies that involve:

- long terms (15+ years);
- questions involving an entire generation system;
- evaluating multiple resource acquisition decisions; and
- a lower level of detail for the production cost simulation.

A CEM should not be used for studies that require:

- a short term;
- a high level of operational detail; and
- decisions that require significant consideration of engineering or other, non-economic, factors.

2. Strategist Overview

For Xcel's IRP, there are three main Strategist modules that are of importance. First, there is the load forecast adjustment (LFA) module. The LFA module contains inputs for energy requirements, demand requirements, and a load shape for a typical week each month. This data is for both the load forecast and energy efficiency programs. The LFA uses these inputs to determine an hourly load shape that allows the energy and demand requirement inputs to be met.[46] Once the LFA determines the system load shape net of energy efficiency, the loads are transferred to the next step, the Generation and Fuel (GAF) module.

The GAF contains numerous inputs for the generating units. In Strategist, generating units are split into two broad categories; non-dispatchable units are referred to as transactions and dispatchable units are referred to as thermal units. Dispatch of transactions happens first. Simply put, transactions are processed as adjustments to the LFA's load curve. Transactions have a defined hourly output and are dispatched regardless of cost.

In the GAF, dispatch of thermal units happens second and is simulated through the use of blocks and a load duration curve. A thermal unit can have several blocks if desired, each with its own heat rate and so forth. The load curve, net of energy efficiency and transactions, is converted into a load duration curve[47] for this step in the process. If any thermal units are labeled as "must run" their minimum blocks are dispatched first—subtracted from the load duration curve. Then, the remaining thermal unit blocks are dispatched in economic order to meet the remaining load. Note that while Strategist can ensure that a minimum amount of spinning reserve is maintained, that generally is as detailed as the GAF gets in treatment of ancillary services.

[46] Note that, under Xcel's inputs, DG is considered as part of the supply module (the GAF) and not the LFA.
[47] A load duration curve sorts the load from highest to lowest MW (by magnitude) rather than chronologically.

The final step occurs in the Proview (PRV) module and is the analysis of expansion units. In each year of the study all combinations of the available alternatives that are allowed by the user are considered. Each unique combination of expansion units is considered a "state".[48] If a state is not feasible[49], it is discarded by Strategist. If a state is feasible, it is saved. In a year, each feasible state from the prior year is considered, one at a time, as a starting point or "origin state". Each origin state can generate additional states to be used as the basis for determining feasible states in the current year. For each origin state, all possible combinations of the origin state and the available expansion units are considered. The optimal plan for the run is determined by ranking the states retained at the end of the last year of the CEM run based upon their cost.

3. EnCompass Overview

As with Strategist, EnCompass starts with a forecast of energy and demand requirements, along with load shapes. While Strategist requires the use of a typical week each month, EnCompass is flexible in allowing the user to define the time frame to be used. For example, an EnCompass run could be done based upon 8,760 hours per year, a typical week each month (2,016 hours per year), or another number of hours per year.

Unlike Strategist, EnCompass does not use blocks and load duration curves. Instead, EnCompass determines a supply curve—stacking the generation in cost order—and dispatches the units chronologically, considering various limits specified in the inputs.

As with Strategist, the final step in Encompass' analytical process is determining the least cost expansion units. In EnCompass the problem of which units to add is first solved by allowing the model to add fractions of units; in essence creating a perfect plan. EnCompass then searches for the best way to round up or down any fractional units added in the perfect plan. The search stops when a solution found that adds only whole units and is within a range of the cost of the perfect plan.

As discussed above, Strategist contains an explicit limit on the number of potential plans that can be considered. While EnCompass does not have such an explicit limit, nonetheless, it does have limits. Specifically, when submitting a scenario to be run, EnCompass calculates the problem size. If the size is too large, a warning is issued by EnCompass with suggestions on how to reduce the problem. For example, a full hourly simulation over 10 years of 50 resources with commitment constraints requires 24 x 365 x 10 x 50 x 8 variables (about 35 million, much too large to solve). Thus, EnCompass faces the same "too much data and analysis" problem as Strategist. A key decision for either an EnCompass or Strategist modeler is how to constrain the size of the problem being analyzed.

One ability EnCompass has that Strategist lacks is the ability to perform Monte Carlo simulations. Monte Carlo analysis analyzes the impact of uncertainty in the inputs. To do this, EnCompass allows the creation of a distribution for an input. Essentially, this creates a pool of potential values for the input. A Monte Carlo

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[48] Strategist has a maximum number of states that can be tracked; here 2,500. The user has several different inputs that limit availability of expansion units and thus can control the number of states. If too many feasible states are created, the states are all ranked based on cost to date and the most expensive states are discarded until the 2,500 state limit is reached.

[49] A state is not feasible if it does not meet all the requirements set by the user. The requirements generally involve meeting reliability requirements, but can involve other considerations such as emission caps, renewable energy requirements, and so forth.

simulation is run numerous times, each time drawing an input out of the pool. The result is a range of potential outcomes. This enables a better analysis of the risk presented by the input.

4. Model Comparison

One difference that immediately stands out is that Strategist cannot use 8,760 hours in a year, even if that level of detail were desired. Instead, Strategist uses a typical week each month. Further, Strategist is not dispatched chronologically, instead it uses load duration curves. Thus, EnCompass has greater flexibility and potentially greater accuracy in dealing with time and issues that are related to time such as unit dispatch. While the Department recognizes this benefit, it must be kept in mind that speculation regarding hourly dispatch 15 years in the future is highly uncertain. The noise inherent in determining the inputs likely drowns out the signal. Further, the dispatch routine likely will be simplified in that actual dispatch in MISO is done for all hours with all load and all units while in IRPs only a portion of the total market units/values will be input and all hours will not be studied for a full 15 years plus end effects run.

When analyzing reliability, both models allow the reliability criteria used by MISO and the Commission to be implemented. The Department is not aware of a significant difference in the two models' ability to deal with reliability (required reserve ratio) considerations.

When analyzing environmental impact, both models allow the Commission approved CO_2 internal cost. In addition, both models have the flexibility necessary to run the Commission required contingencies using combinations of the high, low, and no values. The Department is not aware of a significant difference in the two models' ability to deal with CO_2 internal cost considerations.

When analyzing risk, EnCompass has the capability to be run in the same manner as Strategist. That is, running the model time after time varying an input or set of inputs to determine how sensitive the expansion plan is to various input changes. However, EnCompass' Monte Carlo routine allows an improvement in the risk analysis, assuming that 1) the routine can be set up appropriately and 2) a Monte Carlo run can be completed within a reasonable time.

When considering the modeler rather than the model, the Department, Xcel, and other intervenors have over a decade of experience running Strategist but, at least for the Department and Xcel, no experience (prior to this docket) running EnCompass. The parties' experience with Strategist is an important factor. It does little good for a model, such as EnCompass, to have superior risk analysis abilities, for example, if the modelers either lack the experience needed to use the risk analysis routine or lack the knowledge to appropriately understand what the outputs from the risk analysis indicate. Put another way, Strategist might be said to have capabilities equal to 100 points on a modeling scale, while EnCompass might be said to have 200 points. However, if one modeler can use half of Strategist's capabilities (for a net of 50 points) while another modeler only ten percent of EnCompass's capabilities (for a net of 20 points), then, everything else equal, the Strategist modeling is likely to be much more informative in the short term even if Strategist has greater limitations.

5. Conclusion Regarding Models

Considering the above discussion, for this proceeding the Department decided to use Strategist as its main CEM since the Department can extract far more useful information out of Strategist than out of EnCompass. In addition, the Department has far greater ability to detect and remedy problems in Strategist than EnCompass. Considering the wide range of issues the Commission has required to be addressed in this IRP, the Department's greater knowledge of Strategist is a critical advantage. This means the Department can better assess impacts and outcomes in light of the four primary objectives. It also means the Department can more reliably determine what a preferred plan should be and therefore what is in the public interest. As the Department and other parties become more familiar with EnCompass this tradeoff will lose its importance. However, for now the importance of the greater knowledge of Strategist than EnCompass is clear; using the Department's and Xcel's expertise and experience with Strategist is the prudent thing to do and in the public interest. EnCompass will be used to provide supplemental analysis of certain topics where the Department determined that the additional analysis would be of interest.

J. STRATEGIST MODELING

1. Introduction

For this IRP, the Department used Strategist to review Xcel's modeling efforts. The general process followed by the Department when reviewing Strategist modeling is as follows:

1. obtained from the applicant a base case file, and the commands necessary to recreate the various scenarios explored by the Company;
2. re-ran the applicant's base case file to make sure the outputs match and that the Department is working with the correct file;
3. reviewed the base case's inputs and outputs for reasonableness;
4. created a new base case, which includes any changes deemed necessary to the Company's base case;
5. ran scenarios of interest on the new base case to explore various risks and alternative futures;
6. assessed the results of the scenarios and established a new preferred case; and
7. ran scenarios of interest on the new preferred case to test the robustness of the preferred case.

The Department's overall goal in reviewing a utility's modeling efforts is to determine if the Company's proposed plan results in a reliable, low cost, low impact system that manages risk, and to recommend modifications if needed. Figure 6 below illustrates how the four overall goals were implemented in the Department's Strategist analysis.

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Figure 6: Minnesota Decision Criteria and Modeling

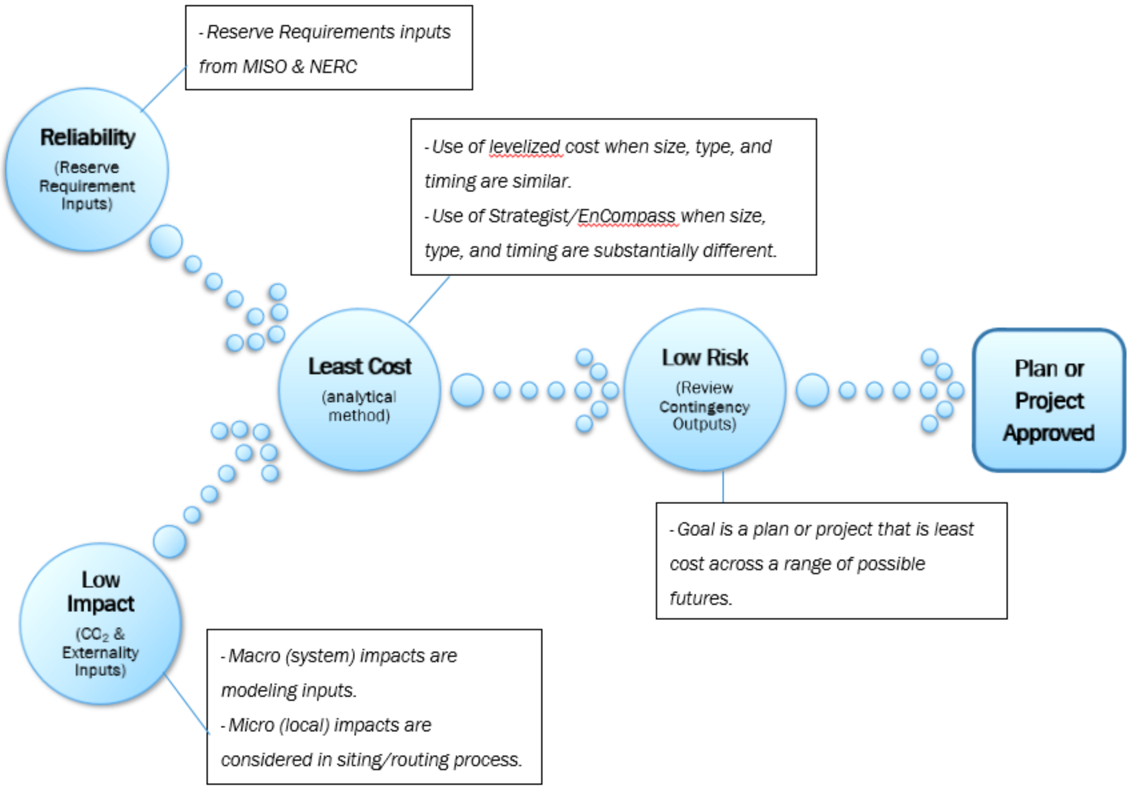

Figure 6 shows that, when evaluating modeling results, the present value of societal costs (PVSC) outputs already include the Commission's reliability and environmental impact criteria. Since Strategist's function is to minimize cost, that is also included in the modeling results. Thus, when evaluating modeling outputs the Department's focus is on understanding why the model is producing the results, the risks inherent in the results, and how the plan contributes to other State goals not reflected in the modeling inputs, such as greenhouse gas reduction goals.

2. Matching Xcel's Results

The first step in the Department's Strategist modeling was to obtain from Xcel the Company's reference case and the commands necessary to re-create the contingencies and scenarios explored by the Company in the Supplement. The Department re-ran the reference case provided by Xcel through Strategist. The Department's outputs matched the results included in the file provided by Xcel. The Department also re-ran the contingencies provided by Xcel through Strategist for the reference case only.[50] Again, the Department's outputs matched the results included in the files provided by Xcel. Finally, the Department re-ran the scenarios provided by Xcel

[50] Xcel's contingencies are labeled A to G, I to M, P, Q, S, and U; see Tables X-7 and X-9 of the Supplement's Attachment A.

through Strategist under base case conditions.[51] Again, the Department's outputs matched the results included in the files provided by Xcel. Finally, the Department compared the outputs in the files provided by Xcel to the information presented in the Supplement. The Strategist outputs matched the information in the Supplement. These results confirmed that Department was working with the inputs that created Xcel's outputs as reported in the Supplement and that modeling could proceed.

The Department noted four items from the file verification process. First, Xcel ran Strategist for the years 2018 to 2045 and included some years with Strategist's end effects routine as well. However, Xcel then reported in the Supplement the costs for the years 2020 to 2045 only. In addition, Strategist discounts costs, for present value purposes, to the model's base year (here 2018) while Xcel reported costs discounted to a different year, 2020. Thus, Xcel reported information differently from what the Company actually ran in Strategist. Due to the mismatch between the Strategist run results and the results reported in the Supplement it is possible that one scenario is lower cost in Strategist but a different scenario is reported as lower cost in the Supplement. The Department did not explore this issue further due to the low likelihood of encountering issues.

Second, Xcel used a mixture of optimizing and re-dispatching in the various runs. Xcel had Strategist optimize the base case and the following contingencies:

- D—low load;
- E—high load
- P—combination of low load, low gas costs, and low resource costs;
- Q—combination of high load, high gas costs, and high resource costs;
- S—no CO_2 MISO prices; and
- U—hourly CO_2 MISO prices.

Meanwhile, Xcel did not have Strategist optimize the following contingencies. Instead, the system resulting from the base case optimization was re-dispatched using the new inputs:

- A—PVRR;
- B—low gas costs;
- C—high gas costs;
- F—low resource costs;
- G—high resource costs;
- I—low externalities in all years;
- J—low externalities and low CO_2 regulatory costs;
- K—mid externalities and mid CO_2 regulatory costs;
- L—high externalities in all years;
- M—no CO_2 externalities;

[51] Xcel's scenarios are labeled 1 to 15; see Tables X-7 and X-9 of the Supplement's Attachment A.

Third, Xcel's Strategist build can retain no more than 2,500 expansion plans (referred to as "states" in Strategist) at the end of any one year. However, when re-running Xcel's scenarios (1 to 15) the Department found that twice Xcel's Strategist inputs resulted in over two million potential states and every scenario (except number 13) exceeded 250,000 potential states in at least one year—that is 100 times the model's capability. When Strategist has more states than it can save in any one year it stacks the states in cost order and discards the states that exceed the model's limit. The result is that a plan that could be least cost at the end of the analysis was discarded by Strategist. The fewer the number of plans discarded and the later in the run the discarding occurs the less likely a least cost plan was artificially discarded. Overall, to the extent possible, it is better for the modeler to decide what plans to discard by controlling the model inputs than to have Strategist artificially discard plans.[52]

Fourth, optimizing the base case in Xcel's 15 scenarios took, on average, a whole day for a single scenario. This is largely due to the number of potential plans Xcel required Strategist to evaluate. Thus, an early objective of the Department's analysis was to speed up the model run time so that the resource plan analysis could be completed in a reasonable time.

3. Review of Xcel's Results

After completing the file verification process, the Department briefly reviewed Xcel's Strategist outputs as reported in the Supplement. The PVSC results for the base case in each scenario are shown in the Supplement's Figure 2-8. The present value of revenue requirements (PVRR) results for the base case in each scenario are shown in the Supplement's Figure 2-9. Similar values for contingencies are shown in the Supplement's Tables X-1 through Table X-12. For ease of reference, Table 10 summarizes the baseload unit retirement dates.

Table 10: Baseload Unit Retirement Dates[53]

	Early	Normal	Extended
King	December 2028	December 2037	N/A
Sherco 3	December 2029	December 2034	N/A
Monticello	September 2026	September 2030	September 2040
Prairie Island 1	September 2024	August 2033	August 2043
Prairie Island 2	September 2025	October 2034	October 2044

[52] For example, by removing alternatives that perform the same function as another alternative such as removing batteries as duplicating the functions of a CT unit.
[53] Retirement is reported based upon the last month of energy production in Strategist scenarios.

Two results stood out in review of Xcel's PVRR/PVSC results. First is the importance of externality values and CO_2 regulatory costs for a decision regarding the coal units and the second is setting a priority between Prairie Island and Monticello for a nuclear license extension.

a. Coal Unit Results

Focusing on Figure 2-8 (Baseload Scenario PVSC Deltas), in each scenario retiring the coal units early—Scenarios 2 (Early King), 3 (Early Sherco), and 4 (Early Coal) versus the Scenario 1 (Reference Case)—all showed net benefits (reduced PVSC compared to the Reference Case) in both Strategist and EnCompass. If it is assumed that a decision is made to retire all of the nuclear units early (Scenario 7 Early Nuclear), retiring the two coal plants as well (Scenario 8 Early Baseload) again shows an improvement, a reduction in PVSC—in Xcel's Strategist results PVSC goes from $692 million increase for Scenario 7 to a $445 million increase for Scenario 8. Similarly, if it is assumed that a decision is made to extend the nuclear units (Scenario 15 Extend Nuclear) retiring the coal units as an additional decision (Scenario 12 Early Coal, Extend Nuclear) shows a further reduction in PVSC. In summary, no matter how the decision is viewed there is a PVSC benefit to early coal retirement. Applying the same analysis to Figure 2-9 (Baseload Scenario PVRR Deltas), in each case[54] the Strategist and EnCompass analysis demonstrated that retiring the coal units early increases PVRR.

In summary, early retirement of the coal units is cost effective in Xcel's base case modeling.

When reviewing the impact of Xcel's contingencies in Strategist[55] early coal unit retirement was generally cost effective except in Contingency A (PVRR), Contingency G (High Resource Cost), Contingency J (Low Externality, Low Regulatory), and Contingency M (No Regulatory or Externality Costs). Occasionally other contingencies would show one early retirement scheme to be not cost effective.

When reviewing the impact of contingencies run in EnCompass,[56] early coal unit retirement was generally cost effective except in Contingency A (PVRR), Contingency M (No Regulatory or Externality Costs), and Contingency S (No Carbon Adder for Sales). Occasionally other contingencies would show one early retirement scheme to be not cost effective.

In summary, early retirement of the coal units is cost effective in Xcel's contingency modeling except when low or no CO_2 internal cost and/or externalities are applied. Thus, use of externalities is important in explaining Xcel's results.

b. Nuclear Unit Results

A comparison of results regarding Prairie Island and Monticello in Figure 2-8 (PVSC results) indicates that the two models do not always agree. In Strategist's results:

- Scenario 15 (Extend Nuclear) has a slightly lower PVSC than Scenario 14 (Extend PI); and
- Scenario 12 (Early Coal, Extend Nuclear) has a lower PVSC than Scenario 11 (Early Coal, Extend Prairie Island).

[54] Scenarios 2, 3, and 4 versus Scenario 1; Scenario 7 versus Scenario 8; and Scenario 15 versus Scenario 12.
[55] See Table X-7 through Table X-10.
[56] See Table X-1 through Table X-4.

Thus, in Strategist, adding Monticello's retirement to that of Prairie Island reduces PVSC. However, in EnCompass the results are reversed:

- Scenario 15 (Extend Nuclear) has a higher PVSC than Scenario 14 (Extend PI); and
- Scenario 12 (Early Coal, Extend Nuclear) has a higher PVSC than Scenario 11 (Early Coal, Extend Prairie Island).

The Department interprets these results to indicate that EnCompass is picking up dispatch-related problems with retaining too much (must run) nuclear capacity on Xcel's system. Xcel's results indicate that the most important decision facing the Commission is the retirement date for Monticello.

Focusing on Figure 2-9 (PVRR results), in both models:

- Scenario 15 (Extend Nuclear) has a higher PVRR than Scenario 14 (Extend PI);
- Scenario 12 (Early Coal, Extend Nuclear) has a higher PVRR than Scenario 11 (Early Coal, Extend Prairie Island).

Again, adding extension of Monticello's license life to an extension of Prairie Island is not cost effective.

When reviewing the impact of contingencies in Strategist[57] comparing Scenario 15 to Scenario 14 (adding Extend Monticello to Extend Prairie Island) shows that the additional extension of Monticello is only cost effective when something is done to raise the level of avoided costs present in the base case: Contingency C (High Gas/Coal/Markets), Contingency E (High Load), Contingency G (High Resource Cost), and Contingency U (Hourly Carbon, Retail Load Shape).

However, comparing Scenario 12 to Scenario 11 (adding Extend Monticello to Extend Prairie Island when retiring coal units early) the additional extension of Monticello is cost effective in approximately half of the contingencies.

When reviewing the impact of contingencies run in EnCompass[58] comparing Scenario 15 to Scenario 14 and Scenario 12 to Scenario 11 adding Extend Monticello to Extend Prairie Island once again is only cost effective when something is done to raise avoided costs [for both comparisons (15 vs. 14 and 12 vs 11): Contingencies C (High Gas/Coal/Markets), E (High Load), and G (High Resource Cost); for one comparison: Contingencies D (Low Load), S (No Carbon Adder for Sales), and V (Optimize with Externality in model)].

Overall, Xcel's analysis in both CEMs shows that adding a Monticello extension to a Prairie Island extension is a high-risk plan.

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[57] See Table X-7 (Strategist Net Present Value Results for Baseload Scenarios PVSC and PVRR, and Sensitivities B-I) and Table X-9 (Strategist Net Present Value Results for Baseload Sensitivities J-U).

[58] See Table X-1 (EnCompass Net Present Value Results for Baseload Scenarios PVSC and PVRR, and Sensitivities B-I) and Table X-3 (EnCompass Net Present Value Results for Baseload Scenario Sensitivities J-V).

4. Department Changes to Xcel's Reference Case

a. List of Changes

The Department made the following changes to Xcel's reference case file to establish a new base case:

- Used the Commission's mid-point externality and CO_2 internal cost values:[59]
  - the Department has always used the mid-point in the base case because it does not weight the analysis towards one extreme or the other.
- Reduced the forecast by approximately 10 percent:
  - see the previously discussed forecast analysis for an explanation;
  - this adjustment impacts the Xcel's base energy/demand forecast and past energy efficiency inputs.
  - this adjustment does not impact:
    - demand response (which is outside the forecast process);
    - electric vehicles (a special forecast also outside of the standard forecast process); and
    - future energy efficiency (which was deemed an alternative, not a forecast process adjustment).
- Changed end effects modeling:
  - see the end effects discussion below.
- Increased fixed costs for Xcel's nuclear units:
  - see nuclear cost discussion below.
- Removed battery and distributed commercial solar expansion units:
  - the units perform the same function as other expansion units available to Strategist, lead to excessive states, and slow run times.[60]
- Added Deuel Harvest wind project:
  - the project was approved in Docket No. E002/M-19-268 after Xcel's cutoff date for changes to modeling inputs.
- Added Elk Creek solar project:
  - the project was approved in Docket No. E002/M-19-568 after Xcel's cutoff date.
- Added Mower County wind project:
  - the project was approved in Docket No. E002/PA-19-553 after Xcel's cutoff date.
- Changed CT and CC expansion unit monthly fuel cost patterns[61]:
  - Xcel's monthly fuel cost patterns for the expansion units were very different from the pattern of existing units and substantially changed the overall fuel cost.
- Changed emissions for certain units:
  - Blue Lake unit 1 pollutant emissions were outside the range of similar units, Blue Lake unit 2 emissions were used instead; and
  - Wheaton units had the lowest CO_2 emission per MWh of any fossil fuel unit, the average of the Inver Hills units was used instead.

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[59] This is Xcel's Contingency K.
[60] The purpose of an IRP is to determine the size, type, and timing of resource additions, not the winning technology. For example, any technology that can act as a capacity resource (namely energy storage and load management) could meet the need. A CT is merely the simplest, easiest understood proxy unit.
[61] The monthly fuel cost pattern is multiplied by the annual fuel cost to get the actual fuel cost used each month.

- Changed capacity market price:
    - Reduced to 25 percent of cost of new entry, see previous discussion of MISO capacity markets.
- Eliminated Xcel's spinning reserve capacity requirement:
    - Xcel's capacity requirement was removed because there is no need to assume Xcel has to solve MISO's ancillary services issues.
- Removed an input attributing CO_2 emissions to MISO spot market energy transactions:
    - it was simpler to for the Department to calculate all spot market CO_2 emissions outside Strategist.[62]
- Locked-in optimization runs:
    - Xcel runs some contingencies as an optimization and some as re-dispatching a pre-existing system, the Department re-optimizes all contingencies.
- Numerous adjustments to expansion unit availability:
    - The tradeoff was to speed up run times (fewer units) while having excess expansion units (more units) of each type available each year after the base case was optimized.[63]
    - Ultimately CC units were removed as an alternative as a CC unit was never selected in about 2,000 draft model runs and the Department did not pursue in detail why the CC unit was not selected.

b. End Effects Discussion

The purpose of including "end effects" in a CEM is to avoid a bias against adding energy intensive units late in the planning period. In past dockets the Department has typically modeled end effects using Strategists' end effects routine. Essentially, this routine repeats the last year of the model run several times. The cost of the optimized years (the planning period) plus the cost of the end effects period equal the cost of the study period, which is reported in comments. In this case, using such a routine was not possible because the standard end effects routine assumes that units available in the last year of the planning period (say 2034) are available or are replaced by a similar unit for the duration of the end effects period. The point of this IRP, in part, is to study shutting down King at the end of 2028 versus shutting down at the end of 2037; assuming that King is replaced in 2038 by a "similar" unit would defeat the purpose of the analysis.

Xcel modeled end effects by running Strategist through the year 2045 and adding five years of standard end effects. This is a reasonable choice as the model is run as an optimization past the last year of a base load units' life, and then standard end effects are added to get the model to the typical 30-year run. The Department would have taken a similar approach but for significant flaws in the Company's inputs after 2034. In addition, the Company's reporting of costs excludes the end effects period and the first two years of the run (2018 and 2019 are run for technical reasons). This creates a difference between the costs the Company reports in the supplement and the costs Strategist actually used to make decisions.

The flaw in the post-2034 inputs is that the impact of new conservation programs increases until 2034 and then declines through the end of the study period. Total energy savings in the first tier of the new programs[64] has a

[62] Note that the spot market price has CO_2 costs embedded in the price, not attached to emissions. Thus, removing CO_2 emissions does not impact CO_2 costs nor does it impact selection of units for the expansion plan.
[63] For example, having 2 wind units available in 2025 when only 1 is selected in the base case allows Strategist to respond by selecting a second wind unit in 2025 when contingencies are run changing fuel prices, load, and so forth.
[64] Referred to as EE_PROG in the model.

compound annual growth rate (CAGR) of 21.5 percent from 2020 to 2034 but the CAGR for 2034 to 2045 is -10.2 percent. The end result is that 9,460 GWh of energy efficiency impact in 2034 decreases to 2,910 GWh of impact in 2045. It is highly unrealistic to assume that new impacts from the state's conservation programs will essentially disappear beginning 2035.

The impact of the flawed assumptions regarding new energy efficiency is significant. For 2020 to 2034 the CAGR for net energy requirements (net of energy efficiency) is -0.2 percent; the CAGR for demand requirements is -0.4 percent—a slowly declining system requirement. However, for 2034 to 2045 the CAGR (net of energy efficiency) reverses; it is +1.7 percent for energy requirements and +2.3 percent for demand requirements.

The Department determined that the simplest way to rectify Xcel's flawed post-2034 inputs (the end effects years) was to model end effects as close as possible to the end effects routine without actually using it. The Department made the following changes for end effects:

- Froze the forecast of energy requirements, capacity requirements, and energy efficiency impacts at the 2035 level[65];
- Extended the lives of generating units still available in 2035 (except the baseload units) to 2045; and
- Ran Strategist as an optimization through 2045.[66]

The Department did not add the five years of standard end effects modeling that Xcel did because of the small impact the out years should have and the difficulty associated with including the cost of standard end effects in the cost numbers reported in these comments.[67]

c. Nuclear Costs Discussion

Global Energy & Water Consulting, LLC (Global) issued a report on December 23, 2020 that reviewed Xcel's decisions regarding license extension or retirement, the capital and operations & maintenance (O&M) costs, and other issues regarding Prairie Island and Monticello. Based upon Global's report the Department made two adjustments to Xcel's reference case modeling inputs.

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[65] Technically, imitating Strategist's end effects process would entail locking-in 2034 data (repeating 2034 to the end of the run). However, the Department deferred the lock-in date to 2035 to align the lock-in with the Sherco unit 3 retirement date. This was done to get a better reading on that retirement decision without creating a significant bias in the other decisions.

[66] When attempting to adjust Xcel's EnCompass data base for the Department's Strategist changes, errors in the Department's end effects adjustments were noted. On the supply side, retirement of the Bayfront 5 and 6 units should have been extended from 2035 to 2045 but was not. This omits about 200 GWh and 20 MW (accredited) annually. On the demand side, the inputs for the electric vehicle forecast, level one demand response and new energy efficiency programs were frozen at the 2034 levels when they should have been frozen at the 2035 levels. Also, the base energy forecast was frozen at a level that was too high. Overall, the energy forecast was frozen at about 1,500 GWh above the intended level and the demand forecast about 150 MW above the intended level. The net impact is to over-forecast demand by about two percent and energy by about four percent. Given the lack of time to re-run all 36 scenarios, the desire to avoid further time extensions in other proceedings, and the over-forecasting result the Department elected to not pursue corrections to the end effects adjustments in Strategist.

[67] The Department was unable to determine a reasonable method to automate the inclusion of end effects costs, so they would have to be added by hand.

The Department's first adjustment was to escalate Xcel's O&M cost inputs. Global's report noted that Xcel has little ability to influence portions of the nuclear plant's O&M costs. Further, Xcel's forecasted O&M inflation costs (growing about 0.25 percent above inflation) is far below the level achieved by the Company historically any lengthy time period going back to the mid-1990s. While the Department agrees with Global that the Company's O&M costs assumptions are "aggressive but attainable" the modeling risk resulting from the inputs is one-sided—similar to Xcel's energy and demand forecasting discussed above. Therefore, to remedy the asymmetric nature of the risks, the Department included an additional one percent annual escalation (CAGR) in O&M costs in the base case changes. This leaves the Department's modeled O&M inflation rate lower than the best level achieved by the Company in the past for a long duration—the escalation in real dollars resulting from the Department's changes is about half the best long-term escalation achieved by the Company. Thus, the Department's inputs assume Xcel will be able to manage O&M costs very well for the foreseeable future.

The Department's second adjustment was to increase Xcel's capital cost inputs. Global's report indicated that the cost of contingencies built into capital cost estimates appear to be under forecast particularly for capital items in outlying years. Global further explains that:

> a contingency is applied during the planning stage to help provide a boundary of what a particular project will cost. The contingency is not a firm cost that must be incurred. It is to be used as a planning and budgeting tool … it does not mean that the Xcel budget is wrong or understated. It simply means there is greater risks associated with these project costs.

Different contingency percentages as applied at different points in the planning and budgeting process. However, Global states that "Not until a project is determined to be necessary and its schedule for deployment is it possible to determine a level of contingency less than 50%." To reflect this planning and budgeting risk directly in the modeling inputs, the Department increased Xcel's nuclear capital cost estimates by 10 percent as part of the base case changes. **[TRADE SECRET DATA HAS BEEN EXCISED]**

5. Scenarios and Contingencies Analyzed by Department

For the baseload retirement study, the Department ran scenarios covering all possible combinations of shutdowns:

- King early and normal;
- Sherco unit 3 early and normal;
- Monticello early, normal, and extended; and
- Prairie Island early, normal, and extended.[68]

This results in 36 scenarios (2x2x3x3=36). The number of scenarios analyzed was made possible due to the significantly decreased model run times resulting from the Department's changes to Xcel's reference case.

In addition to the base case, each scenario was run through 23 contingencies, each varying a single input:[69]

[68] The specific dates are shown in Table 10.
[69] The Department found Xcel's analysis of multiple changes within one contingency to be interesting—this is similar to how MISO does analysis in the MTEP process. But MISO uses only three or four futures which vary a large number of inputs. Here, the length of the individual runs, the large number of scenarios, the difficulty in determining what was causing

- high, middle, low, and no externalities/CO_2 internal costs (seven contingencies);[70]
- high and low solar prices;
- high and low wind prices;
- high and low natural gas prices;
- high and low energy/demand forecast;
- high and low coal fixed costs;
- high and low nuclear fixed costs;
- high and low spot market prices;
- low spot market transmission link limit; and
- no spot market available.

The scenarios and contingencies were analyzed with Xcel's generic 750 MW wind, 500 MW solar, and 374 MW CT units available to determine the approximate size, type, and timing of resource needs.

6. Modeling Results

A summary of the Department's Strategist modeling outputs is provided in Attachment 1. Additional annual capacity and energy data is provided in Attachment 4 and Attachment 5. The Department began reviewing the modeling outputs by sorting the 36 scenarios by PVSC under base case conditions. This sorting is shown in Table 11 below. The goal of this review was to determine if some retirement options performed very well or very poorly, to reduce the number of plans that had to be reviewed to a manageable number.

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changes in outputs when there are several moving parts, and the difficulty in determining what changes to combine meant the Department did not mimic this approach. Also, note that changes in natural gas prices and CO_2 internal costs are reflected in the spot market price to maintain the runs internal consistency.

[70] For example, one contingency will use high externality values instead of the middle values. Another contingency will use high externality values instead of the mid-point, but then switch the high CO_2 internal cost in 2025. Note that since the no externality value and no CO_2 internal cost inputs will be the same ($0 in every case), the results are the same for these two continencies. However, a separate run was performed to ease programming requirements in spreadsheets used to analyze the outputs.

Table 11a: Retirement Scenarios Ranked (top half)

Plan Rank	King Retirement	Sherco 3 Retirement	Monticello Retirement	Prairie Isl. Retirement	Scenario Number
1	Early	Early	Early	Extend	**134**
2	Norm	Early	Early	Extend	**122**
3	Early	Norm	Early	Extend	**126**
4	Early	Early	Norm	Extend	**130**
5	Norm	Early	Norm	Extend	**116**
6	Early	Norm	Norm	Extend	**111**
7	Early	Early	Early	Early	**133**
8	Early	Early	Early	Norm	**131**
9	Norm	Norm	Early	Extend	**119**
10	Early	Early	Extend	Extend	**136**
11	Norm	Early	Early	Early	**121**
12	Early	Early	Norm	Early	**129**
13	Norm	Early	Early	Norm	**113**
14	Early	Norm	Early	Early	**125**
15	Early	Early	Norm	Norm	**112**
16	Early	Norm	Early	Norm	**108**
17	Norm	Early	Norm	Early	**115**
18	Norm	Norm	Norm	Extend	**107**

Amongst the top half of the scenarios, extending the life of Prairie Island is the best performing retirement option; being included in the top six scenarios and in eight of the top 10 scenarios. Early retirement of King also performs strongly, being included in seven of the top 10 scenarios. The same holds for early retirement of Sherco unit 3. Note that the top performing plan involves early retirement of both coal units and Monticello.

As pointed out by Xcel, and agreed to by Global, the Commission does not have to make a final determination regarding Prairie Island in this proceeding. There is time for another round of resource planning before a final decision is necessary. Therefore, assuming an extended life at Prairie Island is not an option at this time or a different decision is made in the future (e.g., either the normal or early retirement dates are ordered), the top two plans that do not include an extended life at Prairie Island (ranks number seven and eight) still involve early retirement of both coal units and Monticello.

Table 11b: Retirement Scenarios Ranked (bottom half)

Plan Rank	King Retirement	Sherco 3 Retirement	Monticello Retirement	Prairie Isl. Retirement	Scenario Number
19	Early	Norm	Norm	Early	110
20	Early	Norm	Extend	Extend	128
21	Norm	Early	Extend	Extend	124
22	Norm	Early	Norm	Norm	103
23	Norm	Norm	Early	Early	117
24	Early	Norm	Norm	Norm	102
25	Norm	Norm	Norm	Early	106
26	Norm	Norm	Early	Norm	104
27	Early	Early	Extend	Norm	132
28	Early	Early	Extend	Early	135
29	Norm	Early	Extend	Early	123
30	Norm	Norm	Norm	Norm	101
31	Early	Norm	Extend	Early	127
32	Norm	Early	Extend	Norm	114
33	Early	Norm	Extend	Norm	109
34	Norm	Norm	Extend	Extend	120
35	Norm	Norm	Extend	Early	118
36	Norm	Norm	Extend	Norm	105

Among the bottom half of the scenarios, extending the life of Monticello is clearly the worst performing retirement option, being included in the bottom six scenarios and in nine of the bottom 10 scenarios. Normal retirement of the coal units also performed poorly, six of the lowest eight ranked scenarios involved the normal retirement date for King; the same was true for Sherco unit 3.

In summary, the result of this step was that early retirement of King, Sherco unit 3, and Monticello clearly stood out. The assumption of a life extension for Prairie Island was also made since it was least cost, knowing that it would be studied again in the next IRP and the ultimate choice did not impact the decision regarding King, Sherco unit 3, and Monticello in this proceeding.

The second step was to evaluate the risks associated with the top ranked scenario (scenario 134). To do this the Department reviewed how Scenario 134 performed in the various contingencies. The result was that this plan was ranked first or second for every contingency except those involving:

- low externality and CO_2 internal costs
  - ranked 4th out of 36 scenarios if only low externality costs are used, 9th if low externalities with a switch to CO_2 internal costs is made;
- no externality and CO_2 internal costs;
  - ranked 13th;
- low natural gas prices;
  - ranked 11th; and
- high nuclear costs;
  - ranked 4th.

Considering the strong performance in most other contingencies, the Department did not consider the results of the low externality/CO_2 cost contingencies to be an over-riding consideration. Also, while the performance in the no externality/CO_2 cost contingencies was mediocre, the Department's and Commission's past practice is to use these contingencies as a standard of comparison and not necessarily a key part of the decision-making. Further, since the nuclear cost risks identified by Global were directly reflected in the modeling inputs the high nuclear cost contingency was of low importance. Finally, the mediocre performance in the low natural gas price contingency was somewhat concerning but, considering the performance in the other contingencies, it was not enough to trigger a change in preferred plan.

The third step was to review the types of new units added and the timing of the additions. In Scenario 134, no expansion units were selected in the 2020 to 2024 period in any contingency, so that data is omitted from Table 12 below. Also, Table 12 shows that, in vast majority of contingencies, the only units added in the late 2020s is a single, 500 MW solar unit (typically in 2029). This means that Scenario 134 has the advantage of shutting down uneconomic units at this time while allowing another round of resource planning before a commitment is made to the size, type, and timing of the replacement technologies.

Under the assumption that the inclusion of an extension at Prairie Island in the preferred plan might prove problematic, the Department also reviewed the results of Scenario 131, which includes the same retirement dates as Scenario 134 except for the Prairie Island units retiring at the normal dates. The results were similar; the addition in the 2020s was a single solar unit, usually in 2029. It was only in Scenario 133—which includes the same retirement dates as Scenario 134 except for Prairie Island retiring early—that additional units are added in the second half of the 2020s. Strategist typically added five solar units (2,500 MW) and one CT unit in the late 2020s when an early Prairie Island retirement is assumed.

Other observations of interest using the contingency run results are possible. First, considering the planning period (2020 to 2034) and setting aside the end effects period for now (2035 to 2045), the expansion plan is not impacted significantly by use of the high externality values in place of the middle values. Also, switching to CO_2 internal costs in 2025 does not significantly change the expansion plan. Using the low externality values does have an impact, but not as much as the Department initially expected, it only removes two solar units. Only completely removing externalities has a significant impact—cutting solar units in half and replacing some of the lost capacity with CT units to meet reliability requirements.

Second, the MW limit on interaction with the Spot Market is important. When the level of access is cut in half the base case addition of 11 solar units in the early 2030s are reduced to only 6 units with lost capacity replaced by two additional CT (capacity) units. If Spot Market access is eliminated solar additions are further reduced to only two units, replaced by a total of four CT units. This demonstrates the importance of access to the Spot Market as a balancing tool for the large amounts of must run generation on Xcel's system. However, the benefits that tool comes with also come with the risks discussed above. Curiously, while the MW limit on Spot Market interaction was important, the level of market prices had only a small impact on the expansion plan; high Spot Market prices converted one solar unit into wind while low prices converted two solar units into a CT unit.

Table 12: Size, Type, and Timing of New Units
(Scenario 134—Early Coal, Early Monticello, Extend Prairie Island)

Contingency	Wind Units 2025-'29	Wind Units 2030-'34	Wind Units 2035-'45	Solar Units 2025-'29	Solar Units 2030-'34	Solar Units 2035-'45	CT Units 2025-'29	CT Units 2030-'34	CT Units 2035-'45
Base Case	-	-	2	1	11	2	-	-	2
Mid Ext., No CO_2 Reg.	-	-	-	1	11	4	-	-	2
High Ext., No CO_2 Reg.	-	-	-	1	11	4	-	-	2
High Ext., Use CO_2 Reg.	-	1	3	1	10	3	-	-	1
Low Ext., No CO_2 Reg.	-	-	-	1	9	3	-	1	2
Low Ext., Use CO_2 Reg.	-	-	-	1	9	3	-	1	2
No Ext., Use CO_2 Reg.	-	-	-	1	6	4	-	2	2
No Ext., No CO_2 Reg.	-	-	-	1	6	4	-	2	2
Low Solar Prices	-	-	2	1	11	4	-	-	1
High Solar Prices	-	1	4	1	3	3	-	3	1
Low Wind Prices	-	3	2	1	6	4	-	1	1
High Wind Prices	-	-	-	1	11	4	-	-	2
Low Forecast	-	-	1	-	10	4	-	-	1
High Forecast	-	-	3	6	7	3	1	3	1
Low Coal Fixed Costs	-	-	2	1	11	2	-	-	2
High Coal Fixed Costs	-	-	2	1	11	2	-	-	2
Low Gas Prices	-	-	-	-	1	4	1	4	2
High Gas Prices	-	3	3	1	8	4	-	-	1
Low Nuke Fixed Costs	-	-	2	1	11	2	-	-	2
High Nuke Fixed Costs	-	-	2	1	11	2	-	-	2
High Spot Market Price	-	1	3	1	10	1	-	-	2
Low Spot Market Price	-	-	-	1	9	3	-	1	2
Low Market Access	-	-	1	1	6	3	-	2	2
No Market Access	-	-	2	1	2	4	-	4	1

Note that wind units are 750 MW nameplate, solar units are 500 MW nameplate, and the CT units are 374 MW nameplate.

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The fourth step was to review the overall system CO_2 emissions for Scenario 134 relative to the emissions of all other scenarios, as shown in Figure 7 below. Figure 7 shows that through 2025, when compared under base case conditions, the Department's preferred plan is at the low end of the range of CO_2 emissions. For the years 2026 to 2029 the preferred plan rises above the low end, largely due to the early retirement of Monticello. For 2030 to 2034 CO_2 emissions are above the low end by a small amount, generally due to the early retirement of Monticello and Spot Market interactions.

Figure 7: Annual System CO_2[71] Emissions

(tons, under base case conditions)

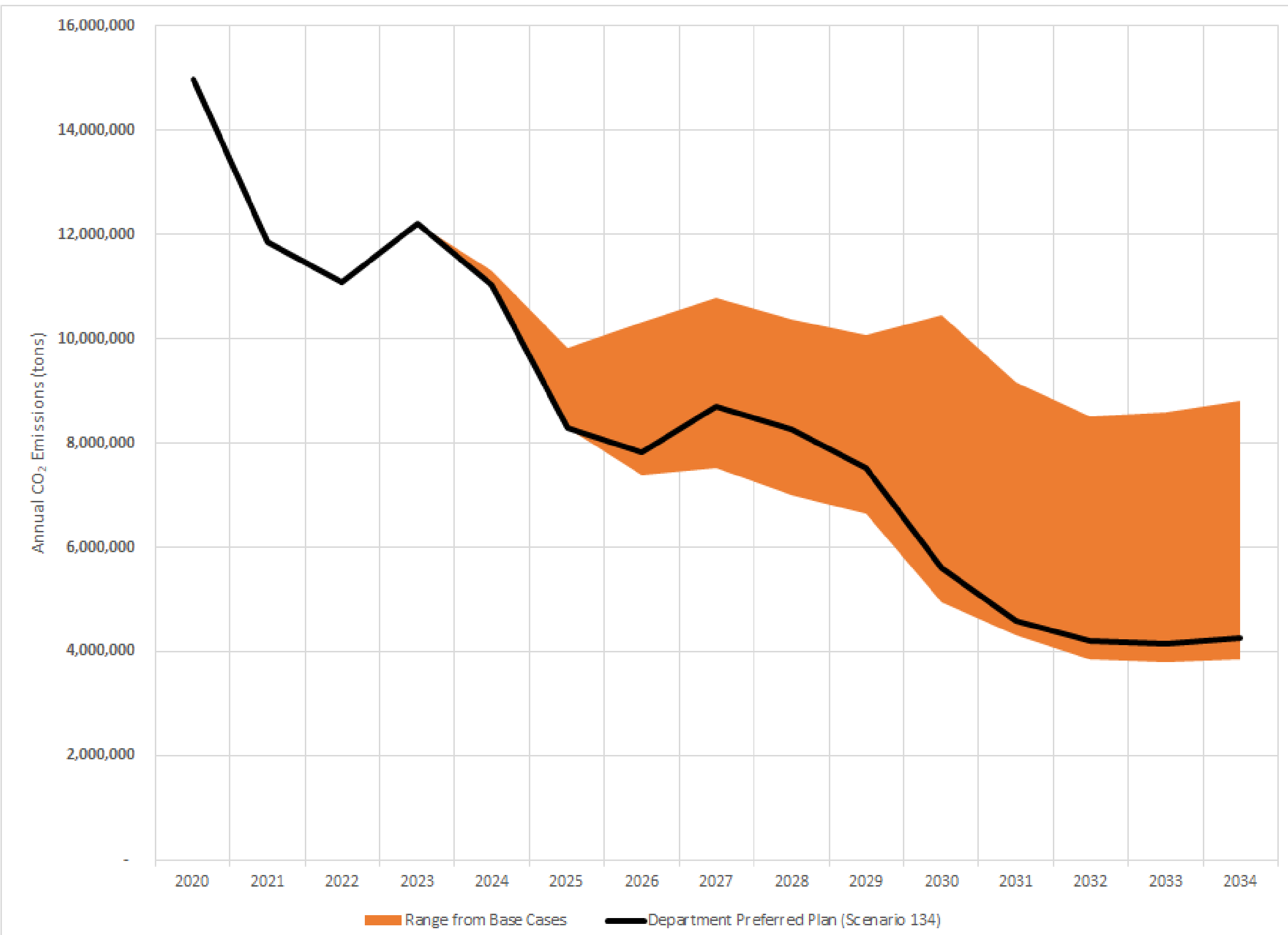
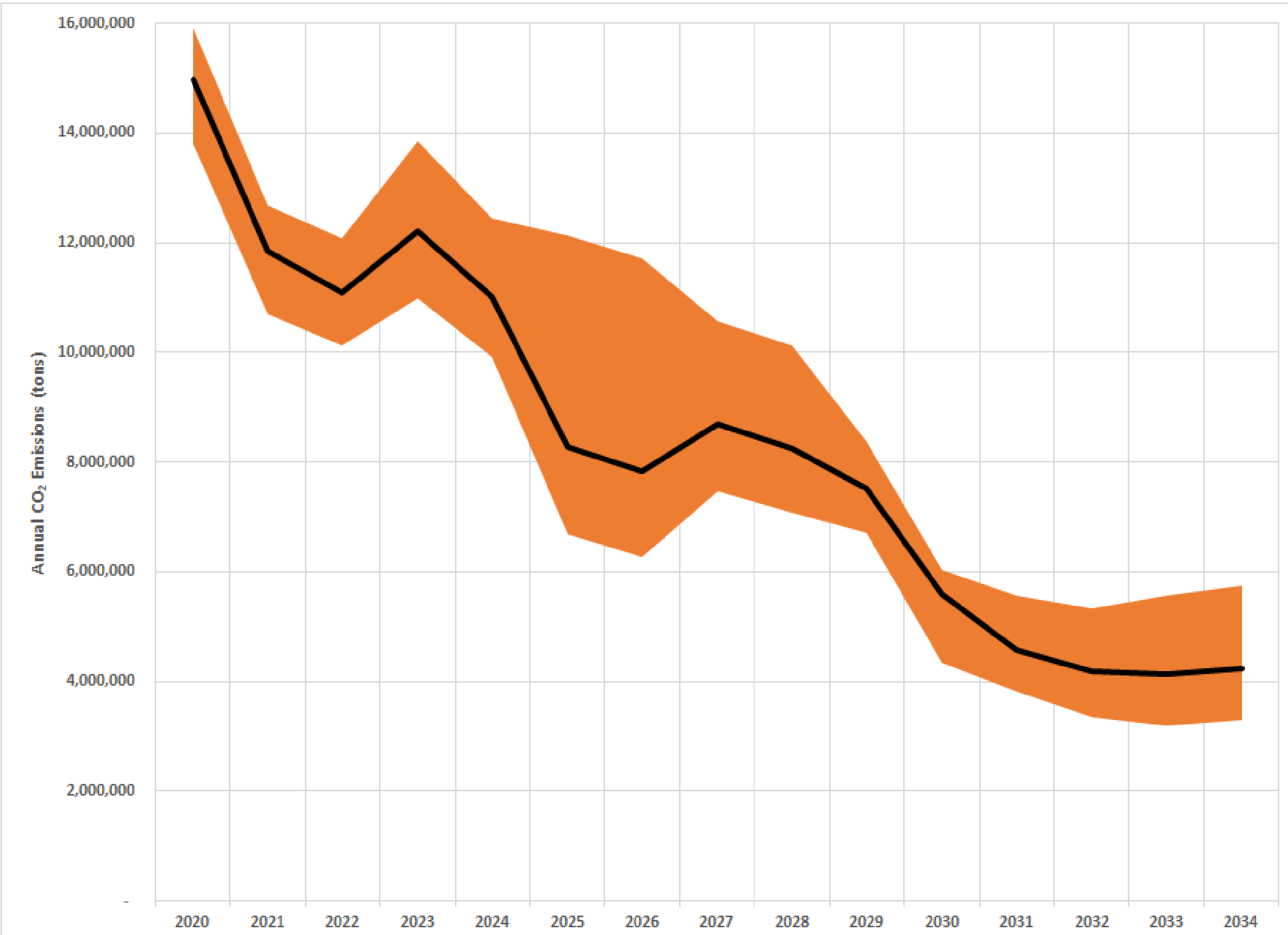


Figure 8 shows the variability in CO_2 emissions of the Department-recommended retirement dates under different assumptions. Figure 8 shows that, except for 2025 to 2027, expected CO_2 emissions are fairly stable, within a band of around two million tons annually.

[71] The Department calculated system CO_2 emissions similar to Xcel. The formula being Xcel's unit emissions, plus emissions from Spot Market purchases—estimated using the forecasted MISO emission rate, minus emissions from Spot Market sales—estimated using Xcel's system average emissions rate.

Figure 8: Scenario 134 Annual System CO_2[72] Emissions (tons, under contingency conditions)



The fifth step was to review the unit capacity factors to see if any potential issues regarding how Strategist was operating could be identified. In general, the Company's peaking units performed as expected. The oil burning CT units never exceeded a 0.5 percent capacity factor. The natural gas CT units also performed as expected, with capacity factors below five percent most years. The only exception was the Company's Black Dog unit 6, which is a relatively new unit. Since the amount of energy produced by the unit in Strategist is relatively small and reflective of the last two years of actual operations, the Department did not investigate further. The baseload units performed to expectations as well. The nuclear units had a sustained, high capacity factor. Sherco unit 3 also sustained a capacity factor above 50 percent. The remaining coal units had a low capacity factor most years, reflecting an economic dispatch designation and relatively low Spot Market price assumptions.

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[72] The Department calculated system CO_2 emissions similar to Xcel. The formula being Xcel's unit emissions, plus emissions from Spot Market purchases—estimated using the forecasted MISO emission rate, minus emissions from Spot Market sales—estimated using Xcel's system average emissions rate.

Some of the Company's intermediate units (Mankato unit 2 and Riverside) showed capacity factors above 50 percent on a sustained basis; the new Sherco CC unit showed capacity factor above 70 percent. In essence, the best CC units are operating as if they were baseload units in Strategist. The Department was concerned that this modeling result might be highly dependent upon the design of the Spot Market. Since the Sherco CC unit showed the highest capacity factor, the Department ran a Strategist scenario (the Department's preferred plan) without the Sherco CC unit to determine where the Sherco CC unit's energy was going. The generation from the version without the Sherco CC unit can be subtracted from the version with the Sherco CC unit to determine the overall impact on Xcel's generation of adding the Sherco CC unit.[73] A summary of the Department's Strategist modeling outputs without the Sherco CC unit is provided in Attachment 3.

For the years 2027 (when the Sherco CC unit comes on-line) to 2034 (end of the planning period) total energy from Xcel's natural gas CC units drops by about 38,800 GWh. The reaction to the decrease in natural gas CC energy can be broken down into the following categories:

- about 51 percent is offset by a decrease in exports to the Spot Market (19,700 GWh);
- about 26 percent is offset by an increase in imports from the Spot Market (10,300 GWh);
- about 17 percent is offset by an increase in solar energy (6,700 GWh); and
- about five percent is offset by an increase in energy from the rest of the units, dominated by the gas CT units (2,100 GWh in all).

Thus, as expected the predominant reaction to removing the Sherco CC unit is to change the Spot Market activity. The decreased exports and increased solar both represent a decrease in overall price risk while the increased imports represent an increase in price risk. The increased energy from all other units represents a change in form of the risk; the transaction changes from buying gas and selling at LMP to buying a variety of fuels (largely gas CT, coal, and nuclear) to meet load. Overall, it appears that removing the Sherco CC unit decreased overall exposure to Spot Market-related risks.

7. Recommendations

The Department recommends the Commission order Xcel to:

- retire the King, Sherco unit 3, and Monticello units on the early dates;
- proceed assuming Prairie Island will undergo a license extension, and re-study the retirement date in the next resource plan;
- acquire solar resources resulting in, approximately, the following total solar capacity:

[73] This is similar to the generation impact analysis in the Department's November 2, 2020 comments in Docket No. E002/M-20-620.

Table 13: Total Solar[74]

Year	Solar MW
2020	990
2021	1,062
2022	1,232
2023	1,298
2024	1,321
2025	1,335
2026	1,348
2027	1,362
2028	1,376
2029	1,889
2030	3,402
2031	5,416
2032	6,429
2033	7,441
2034	7,454

- proceed assuming the Company will not add wind resources during the planning period; and
- proceed assuming the Company will not add capacity resources during the planning period.

K. ENCOMPASS MODELING

1. Introduction

This section has three primary subsections: the Department's Matching Analysis, the Department's New Base, and EnCompass Attachments. Attachment 6 provides a detailed discussion of Xcel's EnCompass database, inputs, process, and related topics. Since Xcel's use of EnCompass is new to Commission proceedings, it may be helpful for parties to read Attachment 6 first.

As described in the Strategist Modeling section above, the Department approached modeling through a series of steps. For EnCompass, the Department attempted to match these steps; however, due the Department's learning curve associated with the software, the Department only was able to partially complete the full Strategist analysis. This Department's progress in EnCompass is shown in the following table:

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[74] Table 13 includes all existing solar, including PPAs, net metering, and solar gardens.

Table 14: Department's Strategist Analysis Steps and Corresponding Progress in EnCompass Analysis to Date

Strategist Step	EnCompass Progress
1. obtained from the applicant a base case file, and the commands necessary to recreate the various scenarios explored by the Company;	Done in part; need to obtain locked in expansion plan datasets for certain scenarios
2. re-ran the applicant's base case file to make sure the outputs match and that the Department is working with the correct file;	Done in part; need to obtain locked in expansion plan datasets for certain scenarios
3. reviewed the base case's inputs and outputs for reasonableness;	Done
4. created a new base case, which includes any changes deemed necessary to the Company's base case;	Mostly done; still assessing whether any further changes to EnCompass new base case are warranted
5. ran scenarios of interest on the new base case to explore various risks and alternative futures;	In progress; outcomes to be presented in Reply Comments
6. assessed the results of the scenarios and established a new preferred case; and	In progress; outcomes to be presented in Reply Comments
7. ran scenarios of interest on the new preferred case to test the robustness of the preferred case.	In progress; outcomes to be presented in Reply Comments

Table 14 shows that the Department's EnCompass modeling is approximately halfway through the series of steps achieved through the Strategist modeling. The Department will continue to follow the Strategist steps with the goal of completing them and presenting outcomes in Reply Comments.

Additionally, in the instant Comments, the Department does not address total costs associated with any plans. This is because prior to determining plan costs, the Department finds it necessary to first validate Xcel's input files (detailed in Section 2, the Department's Matching Analysis), then change certain assumptions to reflect the Department's preferred inputs (detailed in Section 3, the Department's New Base). Finally, the Department is continuing to understand more about how EnCompass and Xcel treat externality costs. From the Department's perspective, plan costs cannot be determined unless these three different things are addressed; the Department will provide total plan costs in Reply Comments.

2. Department's Matching Analysis

Prior to making any changes to the Company's base case, the Department sought to match Xcel's EnCompass modeling results.[75] The primary purpose of this step was to ensure that the Department was using the same files as Xcel. Theoretically, the Department should be able to import Xcel's input files into EnCompass, run the model without making any changes, and produce the same results shown in Xcel's output files. This process is important because it's easy for modelers to use an input file, run the model, obtain an output file, make a slight change to the input file, then save the resulting file. When this happens the inputs in the file did not create the outputs in the file. Put differently, the matching analysis is used as a way to ensure that Xcel's inputs result in a modeling run that produces the output files Xcel generated from its modeling runs and subsequently sent to the Department and other stakeholders. When running Xcel's inputs in EnCompass, if the outputs generated by the Department are different than the outputs Xcel sent to the Department, the Department would be unable to rely on Xcel's inputs and outputs until the source of any discrepancy is determined and corrected. Once the Department is able to produce the same outputs as Xcel using the same inputs that Xcel used, the Department has confidence that the databases are sound and can be used to evaluate Xcel's resource plan.

The first step in this matching process was to import Xcel's input files into EnCompass.[76] The key file to import in this step is Xcel's input file "Final Filed Database_063020." This file "points" to the other listed input files, so once that single file is imported into EnCompass, each of the other input files are also imported. The files are structured in such a way that EnCompass "reads" the files to assemble Xcel's final database.

Once Xcel's database was assembled in EnCompass, the Department ran Scenario 1 without any modifications; in other words, the Department ran Scenario 1 using the file Xcel sent to the Department without making any changes. Once the run was completed, the Department exported the results from the beginning of 2023 through the end of 2045, in alignment with the run parameters submitted by Xcel. The Department chose the following reports to export from EnCompass: Company Annual, Company Capital, and Project Plans.[77]

The Department then compared its Scenario 1 results to Xcel's Scenario 1 results as shown in the "PVSC-PVRR Total" tab of the Company's output file entitled "EO- Base Expansion PVSC PVRR."[78] Specifically, the Department compared the total net present value in 2023 dollars of the Department's versus Xcel's Scenario 1 outputs.

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[75] As described above, this matching process was also performed through the Department's Strategist modeling, and is a common process used by the Department to verify the integrity of modeling data.
[76] EnCompass input and output files were provided to the Department in Department IR 101.
[77] EnCompass's Company Annual report is a high-level look at basic annual figures, such as Company peak and energy use, total generation, purchase and sales information, fuel costs, fixed and variable costs, total operating costs, and externality costs. EnCompass's Company Capital report is a high-level look at annual figures contributing to the utility's revenue requirement, such as operating costs, carrying costs, capital costs, rate of return, and depreciation. The Project Plans report shows project/resource selections for each year of the planning period (for all potential plans), the total plan cost of each potential plan, and the reduced cost of each project/resource selection.
[78] See Xcel's response to DOC IR 101.

As shown in this output file, Xcel's net present value calculation for Scenario 1 comprises three cost components: the EnCompass-generated revenue requirement, the EnCompass-generated externality cost, and the Xcel-calculated externality cost.[79]

After combining the three cost streams, Xcel calculated the net present value of each plan, using 2023 values for expansion plan runs and 2020 values for production cost runs.[80] Initially, it was not clear to the Department why Xcel generated a separate stream of externality costs in addition to those generated by EnCompass. Therefore, the Department requested clarification on this topic during a meeting between the Department and Xcel on January 19, 2021. On February 2, 2021, the Company sent an email to the Department explaining the Xcel-calculated externality cost stream. The Department intends to address this in Reply Comments.

For the Department's purposes of matching EnCompass files, the Xcel-calculated externality values are not relevant. Therefore, the Department removed this cost stream from the equation, then imported its own Scenario 1 outputs into Xcel's workbook.

As background, EnCompass first determines the cost of an ideal expansion plan, adding fractions of units (partial-unit plan). The model then repeatedly tests varying plans that add full units (whole-unit plan). When EnCompass reaches a whole-unit plan whose cost is within a certain fraction of the cost of partial unit plan, the model stops. The fraction is determined by the modeler and is referred to as the Mixed Integer Planning (MIP) stop basis. The basis for the MIP is the "objective function." See Attachment 6 for further discussion of EnCompass' MIP.

The cost most closely aligned with the objective function in EnCompass reports are the sum of the NPV Operating Cost and NPV Carrying Charge Cost from the Company Capital report.[81] Therefore, the Department summed these two costs for both Xcel's Scenario 1 run and the Department's Scenario 1 run. Table 15 shows the results of this comparison; EnCompass direct outputs can be found in Attachment 7.

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[79] Each of these cost components is drawn from another tab in the output file: the Revenue Requirement comes from the "Company Capital" tab, the EnCompass Externality Cost comes from the "Company Annual" tab, and the Xcel Externality Cost comes from the "CSC Calc_exp" tab. The "Company Capital" and "Company Annual" tabs are spreadsheets directly exported from EnCompass.

[80] EnCompass produces both net present value and nominal dollar outputs in the Company Capital report; Xcel's Company Capital cost stream captured the nominal dollar outputs.

[81] In the Company Capital tab, the Net Present Value of a run is shown in the year "0" of a given plan; this value is discounted to the start year of the plan.

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Table 15: Xcel's versus Department's Scenario 1 mixed integer planning assumptions, objective function cost comparison in $2023, and average percent difference

Expansion Plan (2023-2045)	MIP Stop Basis	Operating Cost and Carrying Charge Cost NPV ($000s, 2023)
Scenario 1- Xcel Run	40	$28,499,086
Scenario 1 - Department Match	40	$28,531,223
Delta		$32,137
Average Percent Change		0.11%

Table 15 shows that when the Department ran Scenario 1 exactly as Xcel had submitted it, the Department's operating and carrying charge costs were approximately $32 million greater than Xcel's. However, this is an acceptable level of variation within EnCompass because the percent difference between the costs of Xcel's run and the Department's run is 0.11 percent, which falls within the MIP stop basis value of 40 or 0.40 percent.[82] For the results to be unacceptably different, the percent difference between the two plans would need to be greater than the MIP basis of 0.40 percent. Note that the costs reported in this table are not representative of the total plan costs of Scenario 1; the Operating Cost + Carrying Cost sum is used because it most closely resembles the value of the objective function, which is the basis for the MIP stop gap. In other words, to compare whether two plans have an acceptable level of variation using the MIP stop gap function, the costs to compare are the Operating Cost NPV + Carrying Cost NPV.

The Department then attempted to match Scenario 1-PVSC, the "Production Cost" run of Scenario 1. As explained in Attachment 6, Xcel's production cost runs "lock in" the parent expansion plan, and simply re-run the dispatch within that predetermined set of resources. Therefore, the Scenario 1 run must be complete prior to running the Scenario 1-PVSC run. After the Scenario 1 run was complete, the Department then ran Scenario 1-PVSC with suppressed outputs[83] and used the same comparison methodology as it did for Scenario 1.

The Department's results for Scenario 1-PVSC were not within an acceptable range of the MIP stop basis. Upon further examination, the Department noted that this was because the Department and the Company reached different expansion plan results for Scenario 1. For the MIP stop basis to determine whether two plans fall into an acceptable range, the inputs of those two plans must match exactly. In the case of Scenario 1, Xcel's and the Department's inputs matched because both parties used the same datasets and the same run assumptions. Scenario 1-PVSC, however, uses the expansion plan of Scenario 1 as an input; since the Department and the Company produced slightly different expansion plans from Scenario 1, the Scenario 1-PVSC results could not be compared.[84] The following table shows the total plan cost of Xcel's versus the Department's Scenario 1 results.

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[82] Xcel's expansion plan runs usually have a MIP stop basis value of 40; both the Department's and Xcel's Scenario 1 runs have an MIP value of 40.
[83] Suppressing outputs does not change the analysis, but simply saves space in the database. The Department suppressed "All On-Peak, Daily, and Interval" data associated with the Balancing Authority "NSP."
[84] The Department notes that it is reasonable to come up with slightly different plans (EnCompass versus Strategist). For example, Xcel came up with a slightly different expansion plan. As long as the energy and capacity added is roughly the

Table 16: Xcel's versus Department's Scenario 1 plan cost in $2023 and average percent difference

	Xcel Plan Costs NPV ($000s, 2023)	Department Plan Costs NPV ($000s, 2023)
Scenario 1 Expansion Plan Run	$12,784,358.4	**12,776,957.952**

For the Department to continue its matching analysis of Scenario 1-PVSC, the Department would need to use Xcel's "locked in" expansion plan Scenario 1 results. The Department intends to pursue this analysis in Reply Comments, along with other needed matching runs.

From its matching analysis of Scenario 1, the Department was able to conclude that it was working with the same data that informed Xcel's Scenario 1 expansion plan; however, to validate Xcel's production cost data, more analysis is needed.

After matching Scenario 1, the Department performed its matching analysis on the remaining baseload scenarios (e.g., Scenario 1, Scenario 2, Scenario 3, etc.) and the baseload contingencies (e.g., Scenario 1-A, Scenario 1-B, Scenario 1-C). These results are shown in the following tables; detailed EnCompass outputs can be found in Attachments 7 and 8.

Table 17: Xcel vs. Department baseload scenario expansion plan results ($2023 and percent difference)

Plan	Expansion Plan (2023-2045)	MIP	Operating Cost + Carrying Charges Cost NPV ($000s, 2023)
Scenario 1 (Base)	Xcel	40	$28,499,086
	Dept Match	40	$28,531,223
	Delta		$32,137
	Percent Difference		0.11%
Scenario 2 Early King	Xcel	40	$28,605,346
	Dept Match	40	$28,605,251
	Delta		($96)
	Percent Difference		0.00%
Scenario 3 Early SH3	Xcel	40	$28,544,509
	Dept Match	40	$28,549,251
	Delta		$4,743
	Percent Difference		0.02%

same, differences in type should be expected. For now, the Department understands the difference is largely driven by a difference in the models' dispatch routines.

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Scenario 4 Early Coal	Xcel	40	$28,645,082
	Dept Match	40	$28,599,537
	Delta		($45,545)
	Percent Difference		-0.16%
Scenario 5 Early Monti	Xcel	40	$28,707,694
	Dept Match	40	$28,697,697
	Delta		($9,996)
	Percent Difference		-0.03%
Scenario 6 Early PI	Xcel	40	$29,416,869
	Dept Match	40	$29,458,905
	Delta		$42,036
	Percent Difference		0.14%
Scenario 7 Early Nuclear	Xcel	40	$29,543,505
	Dept Match	40	$29,540,665
	Delta		($2,839)
	Percent Difference		-0.01%
Scenario 8 Early Baseload	Xcel	40	$29,650,556
	Dept Match	45[85]	$29,711,983
	Delta		$61,426
	Percent Difference		0.21%
Scenario 9 Early Coal, Extend Monti	Xcel	40	$28,319,802
	Dept Match	40	$28,237,002
	Delta		$7,201
	Percent Difference		0.03%
Scenario 10 Early King, Extend Monti	Xcel	40	$28,298,720
	Dept Match	40	$28,296,626
	Delta		($2,095)
	Percent Difference		-0.01%
Scenario 11 Early Coal, Extend PI	Xcel	40	$27,901,330
	Dept Match	40	$27,930,431
	Delta		$29,102
	Percent Difference		0.10%
Scenario 12 Early Coal, Extend All Nuclear	Xcel	40	$27,661,844
	Dept Match	40	$27,663,007
	Delta		($1,163)
	Percent Difference		0.00%

[85] The Department was unable to complete the Scenario 8 expansion plan run with Xcel's provided MIP stop basis of 40 but was able to complete the run using a MIP stop basis of 45. The run time for the Scenario 8 expansion plan with a MIP stop basis of 45 was approximately 15 hours, compared to the Department average expansion plan runtime (without Scenarios 8 and 15) of 5.6 hours. It is unclear to the Department at this time how best to compare plans with different MIP values.

Scenario 13 Extend Monti	Xcel	40	$28,193,895
	Dept Match	40	$28,225,361
	Delta		$31,466
	Percent Difference		0.11%
Scenario 14 Extend PI	Xcel	40	$27,751,271
	Dept Match	40	$27,743,821
	Delta		($7,450)
	Percent Difference		-0.03%
Scenario 15 Extend All Nuclear	Xcel	40	$27,521,958
	Dept Match	43[86]	$27,496,665
	Delta		($25,294)
	Percent Difference		-0.09%

Table 18: Xcel vs. Department Scenario 1 contingency expansion plan results ($2023 and percent difference)

Plan	Expansion Plan (2023-2045)	MIP	Operating Cost + Carrying Charges Cost NPV ($000s, 2023)
Scenario 1 (Base)	Xcel	40	$28,499,086
	Dept Match	40	$28,531,223
	Delta		$32,137
	Percent Difference		0.11%
Scenario 1-D (Low Load)	Xcel	50	$29,043,890
	Dept Match	50	$29,071,416
	Delta		$27,526
	Percent Difference		0.09%
Scenario 1-E (High Load)	Xcel	50	$31,526,085
	Dept Match	50	$31,519,627
	Delta		($6,458)
	Percent Difference		-0.02%
Scenario 1-ND Plan	Xcel	40	$27,293,509
	Dept Match	40	$27,286,240

[86] The Department was unable to complete the Scenario 15 expansion plan run with Xcel's provided MIP stop basis of 40 but was able to complete the run using an MIP stop basis of 43. The run time for the Scenario 10 expansion plan with a MIP stop basis of 43 was approximately 35 hours, compared to the Department average expansion plan runtime (without Scenarios 8 and 15) of 5.63 hours. It is unclear to the Department at this time how best to compare plans with different MIP values.

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	Delta		(7,269)
	Percent Difference	-0.03%	-0.03%
Scenario 1- P (High Distributed Solar Adoption Futures: Low Load, Low Gas and Market Prices, Low Resource Cost)	Xcel	50	$27,070,678
	Dept Match	50	$27,006,497
	Delta		(64,181)
	Percent Difference	-0.32%	-0.24%
Scenario 1-Q (High Electrification Futures: High Load, High Gas and Market Prices, Low Resource Cost)	Xcel	50	$27,400,666
	Dept Match	50	$27,528,015
	Delta		$127,350
	Percent Difference		0.46%
Scenario 1- S (No carbon adder for sales)	Xcel	50	$29,991,506
	Dept Match	50	$29,872,062
	Delta		($119,445)
	Percent Difference		-40%
Scenario 1-U (Hourly Carbon Retail Load)	Xcel	50	$28,342,146
	Dept Match	50	$28,346,085
	Delta		($3,939)
	Percent Difference		0.01%
Scenario 1- V (Externalities in Dispatch)	Xcel	50	$29,092,822
	Dept Match	50	$29,000,801
	Delta		($92,021)
	Percent Difference		-0.32%
Scenario 1- 50 ELCC Solar	Xcel	40	$27,572,164
	Dept Match	40	$27,605,013
	Delta		($32,849)
	Percent Difference		0.12%

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The goal of the matching exercise, again, was to validate Table 19 below which shows the input files provided by Xcel and matched by the Department.

Table 19: Input files and corresponding output files provided to the Department by Xcel, identified by Department verification of file

Xcel's EnCompass Inputs Files	Corresponding Output File	Department Matched Expansion Plan Run	Department Matched Production Cost Run
2019 Renewable Shapes Q	EO – Scenario 9 Options2		
2019 Renewable Shapes	EO – Scenario 9 Options2		
CO2 80x31	EO – Scenario 9 Options2		
DR 2	EO - Scenario 9 Options Sens I; EO - Scenario 9 Options Sens J; EO - Scenario 9 Options Sens K; EO - Scenario 9 Options Sens L; EO - Scenario 9 Options Sens M; EO – Scenario 9 Options2		
Early King	EO – Base Expansion PVSC PVRR	x	
Early Monti	EO – Base Expansion PVSC PVRR	x	
Early PI	EO – Base Expansion PVSC PVRR	x	
Early SH3	EO – Base Expansion PVSC PVRR	x	
EE 3	EO - Scenario 9 Options Sens I; EO - Scenario 9 Options Sens J; EO - Scenario 9 Options Sens K; EO - Scenario 9 Options Sens L; EO - Scenario 9 Options Sens M; EO – Scenario 9 Options2		
Extend Monti	EO – Base Expansion PVSC PVRR	x	
Extend PI	EO – Base Expansion PVSC PVRR	x	
Final Filed Database_063020	n/a		
LBC 2	EO – Base Expansion PVSC PVRR	x	
LBC 3	EO – Base Expansion PVSC PVRR	x	
LBC 4	EO – Base Expansion PVSC PVRR	x	
LBC 5	EO – Base Expansion PVSC PVRR	x	
LBC 6	EO – Base Expansion PVSC PVRR	x	
LBC 7	EO – Base Expansion PVSC PVRR	x	
LBC 8	EO – Base Expansion PVSC PVRR	x	
LBC 9	EO – Base Expansion PVSC PVRR	x	
LBC 10	EO – Base Expansion PVSC PVRR	x	
LBC 11	EO – Base Expansion PVSC PVRR	x	
LBC 12	EO – Base Expansion PVSC PVRR	x	

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LBC 13	EO – Base Expansion PVSC PVRR	x	
LBC 14	EO – Base Expansion PVSC PVRR	x	
LBC 15	EO – Base Expansion PVSC PVRR	x	
ND Plan	EO- ND Plan; EO – Base Expansion PVSC PVRR		
NSP_LoadActuals_2019	EO – Scenario 9 Options2		
NSP_ReferenceCase_2020-05-11AM	EO – Base Expansion PVSC PVRR	x	
Optimize Sherco CC	EO – Scenario 9 Options2		
Optimize Wind Storage	EO – Scenario 9 Options2		
Scenario 9 – Solar Storage	EO – Hybrid; EO - Scenario 9 Options Sens I; EO - Scenario 9 Options Sens J; EO - Scenario 9 Options Sens K; EO - Scenario 9 Options Sens L; EO - Scenario 9 Options Sens M; EO – Scenario 9 Options2		
Scenario 9 – Wind Storage	EO – Hybrid; EO - Scenario 9 Options Sens I; EO - Scenario 9 Options Sens J; EO - Scenario 9 Options Sens K; EO - Scenario 9 Options Sens L; EO - Scenario 9 Options Sens M; EO – Scenario 9 Options2		
Sens A – PVRR	EO – Base Expansion PVSC PVRR		
Sens B – Low Gas, Market	EO – Sens B		
Sens C – High Gas, Market	EO – Sens C		
Sens D – Low Load	EO – Sens D	x	
Sens E – High Load	EO – Sens E	x	
Sens F – Low Resource Cost	EO – Sens F		
Sens G – High Resource Cost	EO – Sens G		
Sens I – Low Externality	EO – Sens I		
Sens J – Low Ext, Low Reg	EO – Sens J		
Sens K – Mid Ext, Mid Reg	EO – Sens K		
Sens L – High Externality	EO -Sens L		
Sens M – No Ext, No Reg	EO – Sens M		
Sens N – Markets Off	Provided 2/2/2021		
Sens R – Mkt Prices Shaped to Net Load	Not provided		
Sens S – no carbon adder for sales	EO – Sens S	x	

Sens T – Hourly Carbon Net Load	Not provided		
Sens U – Hourly Carbon Retail Load	EO – Sens U	x	
Sens V – Externalities in Dispatch	EO – Sens V	x	
SHCC 1x1.01	EO - Scenario 9 Options Sens I; EO - Scenario 9 Options Sens J; EO - Scenario 9 Options Sens K; EO - Scenario 9 Options Sens L; EO - Scenario 9 Options Sens M; EO – Scenario 9 Options2		
SHCC 1x1.02	EO - Scenario 9 Options Sens I; EO - Scenario 9 Options Sens J; EO - Scenario 9 Options Sens K; EO - Scenario 9 Options Sens L; EO - Scenario 9 Options Sens M; EO – Scenario 9 Options2		
SHCC 2x1.02	EO - Scenario 9 Options Sens I; EO - Scenario 9 Options Sens J; EO - Scenario 9 Options Sens K; EO - Scenario 9 Options Sens L; EO - Scenario 9 Options Sens M; EO – Scenario 9 Options2		
SHCC Alternatives	EO – Scenario 9 Options2		
Simplify	EO – Base Expansion PVSC PVRR	x	
Solar Storage Optimize	EO – Scenario 9 Options2		
Solar_ELCC-50PCT	EO – Base Expansion PVSC PVRR; EO – 50 Pct ELCC; EO – Scenario 9 Options2	x	
WindAvailable_2023-2025	EO – Scenario 9 Options2		

The Department was unable to compare any of the remaining production cost baseload scenarios—that is, Scenario 1-PVSC, Scenario 2-PVSC, Scenario 3-PVSC. This was for the same reason described above with Scenario 1: the Department's and Xcel's expansion plan results differed slightly in every expansion plan baseload scenario, meaning that no two production cost baseload scenarios used the same inputs, and thus could not be compared using the MIP stop basis criteria. For the Department to perform its matching analysis on the baseload production cost scenarios, the Department would need to use Xcel's "locked in" expansion plans for each baseload scenario. The Department intends to request these locked in expansion plan datasets from Xcel and will complete its matching review of Xcel's baseload production cost scenarios in Reply Comments.

In addition to the contingencies shown above, Xcel examined many additional contingencies only in Scenario 9 (the Company's preferred plan). The Department did not attempt to match any of the Scenario 9 contingencies, as the Department will need to use locked in expansion plan datasets for both Scenario 9. The Department will provide matching analysis of Scenario 9 contingencies in Reply Comments.

The Department intends to continue its matching analysis in Reply Comments. However, the Department does not intend to match every single scenario and contingency examined by Xcel. This is because the goal is to validate datasets used by Xcel; if a dataset can be validated through a single expansion plan run[87] and a single production cost plan run, no further analysis is needed. The Department reasons that since each scenario or contingency corresponds with a particular input file, if the input file can be validated for a given expansion plan run and production cost run, it is unnecessary to keep validating the same file in other runs. This matching strategy is represented visually by the scenarios highlighted in Attachment 9.

At this time, the Department concludes that the inputs for Xcel's baseload and baseload contingency expansion plan runs can be reasonably relied upon to generate the outputs that Xcel provided. The Department further concludes that more analysis is necessary for Xcel's baseload and baseload contingency production cost runs, as well as the Scenario 9 runs.

3. Department New Base

The next step in the Department's process was to form a new base case using the Department's preferred inputs (referred to in these Comments as either the "New Base" or the "Department's New Base"). A new base case means the Department's preferred version of Scenario 1, but instead of modifying Xcel's Base Case, any further analysis will modify the Department's New Base. For example, the Company assumed high externalities/high regulatory costs in its Base Case, whereas the Department prefers to use mid externalities/mid regulatory costs in the New Base. So, the Department replaced the "high externality/regulatory cost" assumption with the "mid externality/regulatory cost" assumptions. By and large, these changes corresponded the same changes made to form the New Base in Strategist.

At a high level, the Department's changes to the Base Case can be grouped into two broad categories: Commission-approved resources and the Department's New Base Dataset.

a. Commission-approved Resources

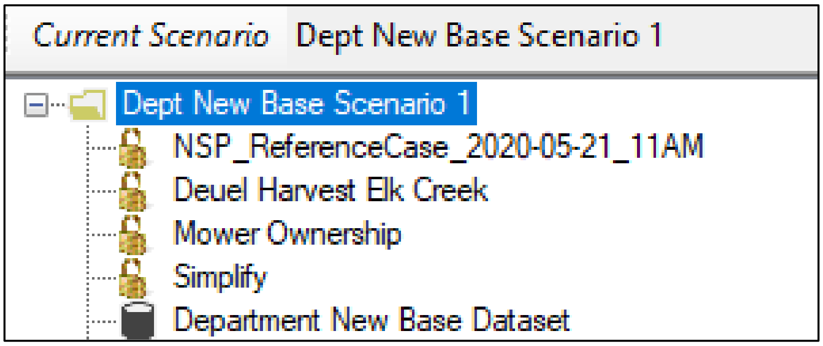
The first step in designing the Department's New Base was to add resources that have been approved by the Commission since the Company's June 30, 2020 Supplement, and thus were not captured in Xcel's Base Case. These are: Deuel Harvest Wind, Elk Creek Solar, and Mower County Wind. Xcel provided two EnCompass-compatible input files to the Department that captured these resources: "Deuel Harvest Elk Creek" and "Mower Ownership." The Department nested these two datasets in Scenario 1 (renamed Dept New Base Scenario 1) under the "NSP_ReferenceCase_2020-05-21_11AM" dataset but before the "Simplify" dataset.

b. Department New Base Dataset

After adding the Deuel Harvest Elk Creek and Mower Ownership datasets, the Department created a new dataset entitled "Department New Base Dataset." The Department left the dataset unlocked and nestled it under the "Simplify" dataset in "Scenario 1," as shown in Figure 9.

[87] If applicable; as submitted by Xcel, not all contingencies are associated with expansion plan runs.

Figure 9: Screenshot of Department's New Base Scenario 1 structure and datasets in EnCompass with Department New Base Dataset Unlocked



The Deparment New Base Dataset contains all subsequent changes made by the Department to form the Department's New Base. This dataset can be uploaded into EnCompass and used to modify any given scenario with the Department's preferred inputs, and will be provided to parties upon request.[88]

i. Mid-Externalities/Mid-Regulatory

The first change the Department made to Department New Base Dataset was to add mid-level externality and regulatory costs, as mentioned in the introduction to this seciton. This was done because Xcel used high-level externality and regulatory costs in its base case, whereas from the Department's perspective, the mid-level externality and regulatory costs are a more reasonable assumption. To implement this change, the Department imported the Company's "Sens K- Mid Ext, Mid Reg" dataset into the Department's New Base Dataset.

ii. NSP Energy and Demand Forecasts

Next, the Department incorporated its preferred NSP energy and demand forecasts. The revised forecasts comprised monthly values (energy in GWh, peak demand in MW) from January 2018 through December 2045. To make this change, the Department first ensured that the correct dataset was being edited (Department New Base Dataset),[89] and copied and pasted the Department's preferred energy and demand data into the "NSP_Monthly_Energy" time series[90] and "NSP_Monthly_Demand" time series, respectively, as shown in Figure 10 below.[91] In EnCompass, as in Strategist, when both the demand and energy of a monthly or annual time series is altered, the hourly dispatch time series is automatically updated to comport with the new values.

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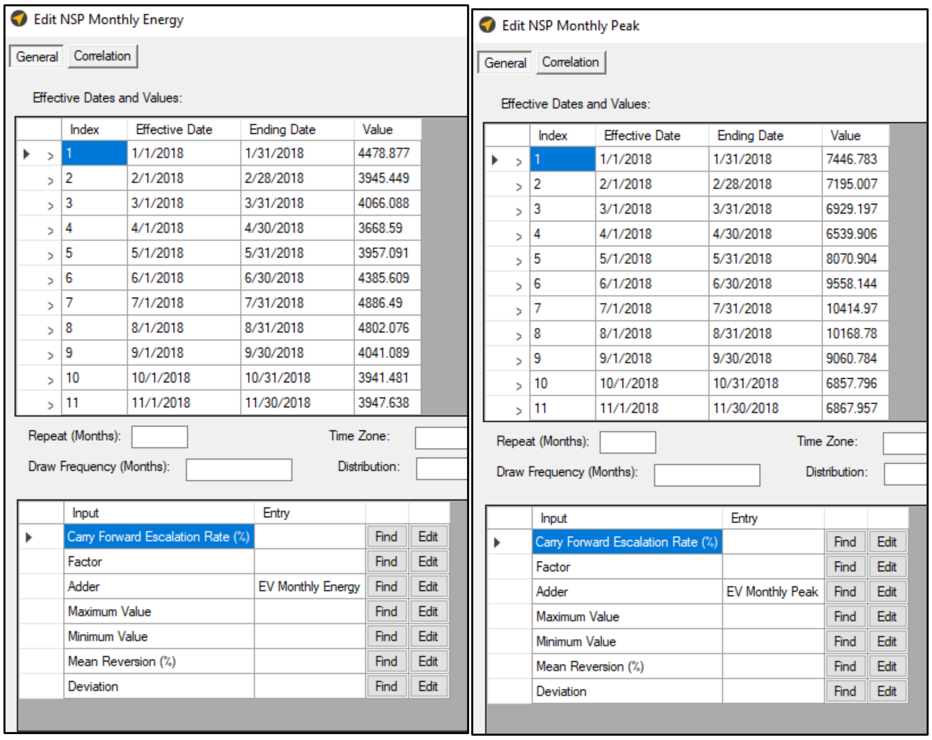
[88] The Deparment's New Base EnCompass dataset must be imported separately from the Deuel Harvest Elk Creek and Mower Ownership datasets, and should be nested in Scenario 1 in the same order as shown in Figure 10 above.
[89] For the remainder of these changes, ensuring that the correct dataset was being edited was the first step taken by the Department.
[90] "Time series" is the term EnCompass uses to describe a specific set or "string" of data, such as the Company's monthly energy forecast over a given time. By contrast, a "dataset" in EnCompass can contain many different sets of data.
[91] Note that EV data is added to both NSP_Monthly_Demand and NSP_Monthly_Peak. The Department's edits to NSP demand and energy forecasts do not change the EV data but do maintain the relationship of the NSP forecast to the EV forecast.

Figure 10: Screenshots of Department edits of NSP_Monthly Energy and NSP_Monthly_Demand in EnCompass with "Greater Than" Symbols Indicating Edited/Saved Data



Index	Effective Date	Ending Date	Value
1	1/1/2018	1/31/2018	4478.877
2	2/1/2018	2/28/2018	3945.449
3	3/1/2018	3/31/2018	4066.088
4	4/1/2018	4/30/2018	3668.59
5	5/1/2018	5/31/2018	3957.091
6	6/1/2018	6/30/2018	4385.609
7	7/1/2018	7/31/2018	4886.49
8	8/1/2018	8/31/2018	4802.076
9	9/1/2018	9/30/2018	4041.089
10	10/1/2018	10/31/2018	3941.481
11	11/1/2018	11/30/2018	3947.638

Input	Entry		
Carry Forward Escalation Rate (%)		Find	Edit
Factor		Find	Edit
Adder	EV Monthly Energy	Find	Edit
Maximum Value		Find	Edit
Minimum Value		Find	Edit
Mean Reversion (%)		Find	Edit
Deviation		Find	Edit

Index	Effective Date	Ending Date	Value
1	1/1/2018	1/31/2018	7446.783
2	2/1/2018	2/28/2018	7195.007
3	3/1/2018	3/31/2018	6929.197
4	4/1/2018	4/30/2018	6539.906
5	5/1/2018	5/31/2018	8070.904
6	6/1/2018	6/30/2018	9558.144
7	7/1/2018	7/31/2018	10414.97
8	8/1/2018	8/31/2018	10168.78
9	9/1/2018	9/30/2018	9060.784
10	10/1/2018	10/31/2018	6857.796
11	11/1/2018	11/30/2018	6867.957

Input	Entry		
Carry Forward Escalation Rate (%)		Find	Edit
Factor		Find	Edit
Adder	EV Monthly Peak	Find	Edit
Maximum Value		Find	Edit
Minimum Value		Find	Edit
Mean Reversion (%)		Find	Edit
Deviation		Find	Edit

iii. Historic Energy Efficiency Forecast

The Department next incorporated its preferred historic energy efficiency demand forecasts into Xcel's FUTDSM_Peak and HISTDSM_Peak time series. The revised historic energy efficiency forecast comprised lower monthly peak demand values from January 2018 through December 2045. This is similar to the change made to the base forecast. To make this change, the Department copied and pasted the Department's preferred demand data into "FUTDSM_Peak" and "HISTDSM_Peak."

In Strategist, but not EnCompass, the Department also changed the monthly energy forecasts associated with FUTDSM and HISTDSM. Rather than using monthly energy data for these resources, EnCompass used hourly dispatch data; these time series are referred to as "FUTDSM_Load_Shape" and "HISTDSM_Load_Shape." These shapes were not changed; as a result, FUTDSM and HISTDSM energy is different between the Strategist and EnCompass models. It is unclear to the Department what, if any, impact this would have on the outcomes of the new base in Strategist versus EnCompass. However, the Department notes that the EnCompass hourly shapes are based at least in part on the Strategist monthly data.[92]

[92] In an email to the Department on January 25, 2021, Norm Richardson from Anchor Power Solutions described the process of converting Strategist monthly energy data to EnCompass hourly shapes data.

iv. End Effects

"End effects" refers to the treatment of load and resources after planning period ends in 2034. As discussed elsewhere, the purpose of end effects is to eliminate a bias against adding energy producing units late in the planning period by allowing the energy value to be realized. If a run was performed using only the planning period (2020 to 2034) it would be difficult for EnCompass to justify adding energy intensive units late in the planning period. Running the model past 2034 allows a better assessment of energy-related benefits.

To account for end effects, modelers will stabilize the last portion of the planning period by freezing the system at a given point in time. In EnCompass, the Department chose to "freeze" the 2035 year. To do this, the Department made the following changes, which were also made in Strategist:

- NSP Energy and Demand Forecasts: The Department built an end effects treatment into the NSP energy and demand forecasts mentioned above by freezing the 2035 year; thus, the monthly data of 2035 is repeated each year from 2036 through the end of 2045 for the NSP_Monthly_Energy time series and NSP_Monthly_Peak time series.
- DSM Demand Forecast: The Department built an end effects treatment into the DSM demand forecasts mentioned above by freezing the 2035 year; thus, the monthly data of 2035 is repeated each year from 2036 through the end of 2045 for the FUTDSM_Peak time series and HISTDSM_Peak time series.
- Distributed Solar Capacity: The Department used Xcel's 2035 monthly values in the "DGSolar_Capacity" and "CSG_Capacity" time series; the 2035 data for each was repeated from 2036-2045.
- Demand Response Capacity: The Department used Xcel's 2035 annual value and repeated it each year from 2036 through 2045 for the following time series: DR_CP_1_Capacity, DR_INT_1_Capacity, DR_SS_1_Capacity, DR_INT_2_Capacity, DR_INT_3_Capacity, DR_SS_2_Capacity, and DR_SS_3_Capacity.
- Direct Load Control: The Department repeated Xcel's 2035 monthly values for INT_DLC_Capacity and the 2035 annual value for Xcel's SS_DLC_Capacity for each year from 2036 through 2045.
- Electric Vehicle Energy and Demand: The Department repeated Xcel's 2035 monthly values for each year from 2036 through 2045 for the "EV_Energy" and "EV_Peak" resources.
- Energy Efficiency Demand: The Department repeated Xcel's 2035 monthly values for each year from 2036 through 2045 for the following values: EE_OTP Peak, EE_MAX Peak, and EE_PROG Peak. Note that similar to HISTDSM and FUTDSM, the Department did not attempt to replace the hourly load shapes of these resources with monthly energy forecasts.
- Non-Baseload Retirements: the Department changed the retirement dates for the following list of resources, including PPAs, which were non-baseload plants set to retire between the beginning of 2035 and the end of 2045. The Department set the retirement date of each of the following resources at 12/31/2045:

  - StNotreDame SolarPV
  - Deuel Harvest
  - Aurora
  - Mankato Energy Center 2
  - CleanEnergy1
  - BorderWinds
  - PleasantValley
  - Angus Anson 3
  - Angus Anson 2

- Elk Creek
- North Star
- Courtenay
- Marshall
- Foxtail
- Crowned Ridge PPA
- LakeBenton2Repower
- Jeffers
- CommWindNorth1
- BlazingStar1
- Blue Lake 8
- Blue Lake 7
- Angus Anson 4
- CrownedRidgeBOT
- Mower Co- Owned
- Blazing Star 2
- Freeborn
- Odell
- Nobles
- Bayfront 5
- Bayfront 6

v. Fuel Prices: Generic Gas Resources

For the Generic CT and Generic CC resources, Xcel developed and used new fuel price data, "Gas.Natural.GenericCT" and "Gas.Natural.GenericCC," respectively. The Department changed Xcel's Generic CT resource to use the fuel price of the Company's Invenergy Cannon Falls CT[93] and changed Xcel's Generic CC resource to use the fuel price of the Company's Black Dog CC.[94] This was done to ensure that the generic resources experienced similar price patterns as other comparable resources.

vi. MISO: Capacity Market Prices

For the MISO capacity market price, Xcel used the maximum Cost of New Entry (CONE) price. The Department adjusted this to reflect the average CONE price by multiplying the "MISO_Capacity_Prices" value ($54.84) by 0.25 to get $13.71. See the capacity market price change discussion in the Strategist section above for further analysis.

vii. MISO: Spinning Reserves Requirement

[93] In EnCompass, the Department performed the following actions: opened CT_H_GR, clicked "Thermal," clicked "Find" under "Delivery Point," selected "Gas.Natural.Cannon Falls."
[94] In EnCompass, the Department performed the following actions: opened CC_H_GR, clicked "Thermal," clicked "Find" under "Delivery Point," selected "Gas.Natural.Blackdog."

Xcel's EnCompass modeling included a spinning reserves requirement for MISO; however, Xcel is under no obligation to meet MISO's spinning reserves requirement. MISO's requirements can be met by any market participant. Therefore, the Department deleted this requirement.[95]

viii. Emissions

The Department found certain emissions rates problematic. The first of these was CO_2 release rates for MISO; Xcel is under no obligation to meet or track MISO CO_2 emissions. Therefore, the Department removed this emissions rate.[96] Additionally, the Department found the CO_2 emissions associated with Wheaton units 1-4 and 6 and Blue Lake unit 1 to be inconsistent with the ages and types of plants. For Wheaton units 1-4 and 6, the Department set the CO_2 emissions to 3360, the average of Inver Hills units 1-6 emissions. For Blue Lake unit 1 emissions, the Department set these to Blue Lake unit 2.

ix. Additional Changes in Strategist

There were several changes made in Strategist but not in EnCompass to create the Department's New Base. One of these, as discussed above, was changes to the energy forecasts of the FUTDSM and HISTDSM resources. Additionally, various technical changes were made in Strategist that did not apply to EnCompass. Further, the Strategist New Base removed certain resources that were never chosen under any circumstances; this was to save on run time.

[95] To do this, the Department performed the following actions: under Demand, edit the Region (the top section), and remove the entries for Operating Reserves and Spinning Required (or set them to 0).
[96] To do this, the Department performed the following actions: under Area, edit the Area Connection with MISO, and remove the entries for CO_2 release rates (or set them to 0):

a) Department New Base Dataset

In developing its new base case in Strategist, the Department made a number of changes to Xcel's base case assumptions. However, not all changes made to form the new base in Strategist were subsequently made to form the new base in EnCompass. The following table shows Xcel's versus the Department's base case assumptions in Strategist and EnCompass.

Table 20: Xcel base case assumptions, Department new base case Strategist assumptions, Department new base case EnCompass assumptions; assumption alignment demarcated by shading

Xcel Base Case Assumption	Department Strategist New Base Case Assumption	Department EnCompass New Base Case Assumption
Did not include Commission-approved resources	Added Commission-approved resources Deuel Harvest Wind, Elk Creek Solar, Mower County Wind (used Xcel datasets)	Added Commission-approved resources Deuel Harvest Wind, Elk Creek Solar, Mower County Wind (used Xcel datasets)
Used high externalities/regulatory costs	Used Xcel's mid externalities/regulatory costs (used Xcel dataset)	Used Xcel's mid externalities/regulatory costs (used Xcel dataset)
Used NSP Energy and Demand Forecasts	Used Department's monthly energy and demand load forecasts instead of Xcel's forecasts with End Effects repeated 2035 monthly data from beginning of 2036 through end of 2045	Used Department's monthly energy and demand load forecasts instead of Xcel's forecasts with End Effects repeated 2035 monthly data from beginning of 2036 through end of 2045
Used Historic Energy Efficiency *Demand* Forecast, No End Effects	Used Department's monthly demand forecast instead of Xcel's for impacts of pre-2020 energy efficiency with End Effects repeated 2035 monthly data from beginning of 2036 through end of 2045	Used Department's monthly demand forecast instead of Xcel's for impacts of pre-2020 energy efficiency with End Effects repeated 2035 monthly data from beginning of 2036 through end of 2045
Used Historic Energy Efficiency *Energy* Forecast (in Strategist, this would be monthly data, and in EnCompass, this would be hourly shapes), no End Effects	Used Department's monthly energy forecast instead of Xcel's for impacts of pre-2020 energy efficiency with End Effects repeated 2035 monthly data from beginning of 2036 through end of 2045	Used Xcel's hourly shapes for energy efficiency energy forecasts, no End Effects
No End Effects for: Distributed Solar Capacity, Electric Vehicle Energy and Demand, Energy Efficiency Demand, Demand Response Capacity	Repeated Xcel's 2035 monthly data from beginning of 2036 through end of 2045 for: Distributed Solar Capacity, Electric Vehicle Energy and Demand, Energy Efficiency Demand, Demand Response Capacity	Repeated Xcel's 2035 monthly data from beginning of 2036 through end of 2045 for: Distributed Solar Capacity, Electric Vehicle Energy and Demand, Energy Efficiency Demand, Demand Response Capacity
No End Effects for: Non-Baseload Retirements	Extended all non-baseload resources set to retire between the beginning of 2035 and the end of	Extended all non-baseload resources set to retire between the beginning of 2035 and the end of

	2045 to retire on December 31, 2045.	2045 to retire on December 31, 2045.
Used aggressive capital and O&M costs for nuclear units	Increased capital cost inputs and O&M cost escalation factor for nuclear units	Used Xcel's capital and O&M cost inputs for nuclear units
Used Generic Resource Fuel Prices for Generic CT and Generic CC units	Changed Xcel's Generic CT price to Xcel's Invenergy Cannon Falls price; changed Xcel's Generic CC price to Xcel's Black Dog price	Changed Xcel's Generic CT price to Xcel's Invenergy Cannon Falls price; changed Xcel's Generic CC price to Xcel's Black Dog price
Set MISO Capacity Market Prices at maximum Cost of New Entry (CONE) price	Changed Xcel's value Cost of New Entry (CONE) from the maximum price to the average price	Changed Xcel's value Cost of New Entry (CONE) from the maximum price to the average price
Included a MISO spinning reserves requirement	Eliminated Xcel's spinning reserve requirement	Eliminated Xcel's spinning reserve requirement
Included an input attributing CO_2 emissions to MISO spot market energy transactions	Removed an input attributing CO_2 emissions to MISO spot market energy transactions	Removed an input attributing CO_2 emissions to MISO spot market energy transactions
Used CO_2 emissions for Blue Lake 1 and Wheaton 1-4 and 6 that were dissimilar to comparable units	Changed CO_2 emissions for Blue Lake 1 and Wheaton 1-4 and 6 to be more similar to comparable units	Changed CO_2 emissions for Blue Lake 1 and Wheaton 1-4 and 6 to be more similar to comparable units
Included all generic Battery, Demand Response, and Combined Cycle Units as potential expansion options	Removed certain unused generic Battery, Distributed Commercial Solar, Demand Response, and Combined Cycle Units to save on model run time	Included all Battery, Demand Response, and Combined Cycle Units as potential options
All production cost runs ran using locked-in expansion plans	Optimized all production cost runs to create new expansion plans	Optimized all production cost runs to create new expansion plans

Moving forward, the Department intends to incorporate the adjusted nuclear costs into the EnCompass new base and attempt to remove unused generic resources, in alignment with its new base development in Strategist.

4. Strategist vs. EnCompass New Base Expansion Plans

Once the Department had designed the EnCompass New Base, the Department then ran Department New Base Scenario 1 as an expansion plan run. The Department left the Scenario 1 solve parameters the same as Xcel's Base Case, with one exception: rather than use a start year of 2023 (as Xcel's Scenario 1 and other expansion plan runs had done), the Department used an EnCompass New Base start year of 2020. This was done to better match Strategist. Additionally, through trial and error, it became clear that some EE/DR resources were being selected in 2020, and the Department wished to show those in results.

Once the EnCompass New Base Scenario 1 run was complete, the Department then compared its results to the Strategist New Base Scenario 1 results. Table 21 shows the total differences between these two plans.

Table 21. Expansion Plan Differences, EnCompass versus Strategist New Base

Expansion Plan Change	**EnCompass New Base**	**Strategist New Base**
Retirements	5	5
Wind Units Added	2	2
Solar Units Added	10	14
EE/DR Resources Added	5	5
Combined Cycle Units Added	1	1
Combustion Turbine Units Added	4	2
Battery Units Added	0	0

The Department notes that EnCompass and Strategist New Base models have the following expansion plan aspects in common: number of retirements, number of wind units added, number of EE/DR units added, number of combined cycle units added, and number of battery units added. The plans differ in the following resources: number of solar units added and number of combustion turbines added. The Department has seen a trade off in expansion plans between solar units and combustion turbines in other proceedings.

One note on the EE/DR resources: these resources appear to be accounted for differently in EnCompass versus in Strategist. As modeled, Strategist only selected three EE/DR resources instead of five. However, this seems to be explained thusly:

- EnCompass selects the following five units in 2020: DR_CP_1, DR_INT_1, DR_SS_1, EE_1, and EE_2.
- Strategist selects the following three units in 2020: EE_1, EE_2, and DR_1 (DR_1 is not a resource found in EnCompass at all). In Strategist, DR_1 was linked to DR_SS_1; separately, DR_SS_1 was bundled with DR_INT_1 and DR_CP_1, so that three units are added by a single Proview unit (DR_1). This means that in total, Strategist adds five units in 2020: EE_1, EE_2, DR_SS_1, DR_INT_1, and DR_CP_1.

Table 22 below shows the full expansion plans with dates for each of the selections.

Table 22: Expansion Plan Selections, Strategist vs. EnCompass New Base Scenario 1, 2020-2045

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
EnCompass Retirements											1			1	1	1			1							
Strategist Retirements											1			1	1	1			1							
EnCompass Solar Added													3	3	2	2										
Strategist Solar Added												2	2	2	3	5										
EnCompass Wind Added															1				1							
Strategist Wind Added																			2							
EnCompass EE/DR Adds	5																									
Strategist EE/DR Adds	3 (5)																									
EnCompass CC Added								1																		
Strategist CC Added								1																		
EnCompass CT Added												1			1	1			1							
Strategist CT Added														1					1							
EnCompass Battery Adds																										
Strategist Battery Adds																										

The five retirements in each New Base Scenario 1 correspond to each of the baseload plant retirements (King, Sherco unit 3, Monticello, and Prairie Island units 1 and 2). Recall that in Scenario 1, each baseload plant retirement proceeds as currently scheduled, and this was not altered in the Department's New Base Scenario 1. The one combined cycle unit addition refers to Sherco CC, which is scheduled to be added in 2027. No battery units were chosen for the duration of the planning period in either New Base Scenario 1.

The three primary differences between the plans are:

- The models select for wind additions on different timetables; while EnCompass adds one wind unit in 2034 and another in 2038, Strategist adds two in 2038
- The models select for solar additions on different timetables, with Strategist selecting for more solar unit additions than EnCompass. While EnCompass adds 10 solar units between 2032 and 2035 with the majority of additions occurring in the first half of that time period, Strategist adds 14 solar units between 2031 and 2035 with the majority of additions occurring in the second half of that time period.
- The models select for combustion turbine (CT) units on different timetables, with EnCompass selecting for more CT unit additions than Strategist. EnCompass adds four units over a more extended timeframe (2031 to 2038), while Strategist adds one CT unit in 2033 and one CT unit in 2038.

Overall, the Department concludes that the EnCompass New Base Scenario 1 expansion plan seems to prefer CT units to solar units, as compared to Strategist. It is unclear to the Department at this time whether this is random or the result of a particular reason such as system dispatch. As noted above, there are a few differences between the design of the Department's new base case in Strategist versus EnCompass, most notably the energy forecast of the HISTDSM and FUTDSM time series. Further, it may be that Strategist and EnCompass treat CT or solar units differently in some way, as was the case for the five EE/DR units added in 2020 under these expansion plans. Finally, it may be that Xcel used different underlying assumptions in its Strategist versus EnCompass data that would explain the difference in preferences between the two programs.

In addition to the intended changes mentioned above, Department will continue to evaluate whether the EnCompass New Base should be further altered in some way to more closely mimic the Strategist New Base; however, if no new information can be found, the Department will continue to move forward with its analysis using this EnCompass New Base.

L. ASSESSMENT OF ENERGY EFFICIENCY RESOURCES

In Docket No. E002/RP-15-21, the Commission established an average annual energy savings goal of 444 GWh for all planning years.[97] In the Supplement, Xcel proposed average annual energy savings goal of 780 GWh. The Department compared the average annual energy savings goals from the two IRPs with Xcel's actual 2015-2019 GWh savings.[98] The Supplement's average annual energy savings do not actually apply to the 2015-2019 period. However, for purposes of comparing the Commission-approved average energy savings goal from the 2015 IRP and the average energy savings goals proposed in the Supplement, the Department assumed the Company's proposed goals were for 2015-2019. Table 23 below compares the average annual energy savings goals from the two IRPs with Xcel's actual 2015-2019 GWh savings.

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[97] *In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan, Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings,* January 11, 2017*,* Order Point 11 at 11.
[98] Although Xcel's 2020 actual GWh achievements are not presently available, they should be available before Reply Comments are due in this filing.

Table 23: Comparing Five Years of Xcel's Actual Energy Savings Achievements With Five Years of Xcel's 2015 IRP Average Annual Energy Savings Goals and Five Years of Xcel's Proposed Annual Energy Savings Goals

	First-year GWh Achievements	2015 IRP Goal (GWh)	Achieved vs. 2025 IRP (GWh)	2019 IRP Goal (GWh)	Achieved vs. 2019 IRP (GWh)
2015	502	440	62	780	(278)
2016	554	440	114	780	(226)
2017	660	440	220	780	(120)
2018	680	440	240	780	(100)
2019	529	440	89	780	(251)
2015-2019	2,926	2,200	726	3,900	(974)

Table 23 shows that Xcel achieved almost 3,000 GWh of first-year energy savings between 2015 and 2019. These first-year energy savings approximate 133 percent of five years of the Xcel average annual energy savings required from Xcel's 2015 IRP, but only 75 percent of five years of Xcel's proposed average annual energy savings goal for the 2019 IRP. [99]

The Department did not conduct a detailed analysis of the Company's proposed level of energy efficiency resources for its 2019 IRP. The Department concluded that Xcel's proposed level of energy efficiency was a reasonable proxy for the decision that would be made within the CIP process and the energy efficiency ultimately achieved by Xcel. Therefore, the Department's analysis treated the Company's proposed energy efficiency achievements as a locked-in resource.

However, the Department did re-run the 36 scenarios assuming the highest level of energy efficiency is achieved to see if higher achievement would impact the Department's overall recommendation. A summary of the Department's Strategist modeling outputs assuming the higher level of energy efficiency is provided in Attachment 2. To be clear, the higher achievement level was not run to be compared with the Company's proposed level of achievement on a cost basis because the Department did not review Xcel's proposed energy efficiency costs for reasonableness. Instead the differing levels of energy efficiency were run to determine if there was a significant impact on the ranking of the scenarios and upon the expansion units selected.

Overall, assuming the higher level of energy efficiency is achieved did not change the top ranked scenario under base case conditions—early coal retirement, early Monticello retirement, and extending Prairie Island was still the least cost plan. In addition, among the top 12 plans early retirement of King and Sherco unit 3 were selected the same number of times. Among the top 12 plans the change was that extending the life of the nuclear units was selected slightly less often.

The expansion plan impact of higher energy efficiency was also minimal. The most common result when comparing the contingencies was that the same number of CT and wind units were added while selecting five

[99] Xcel achieved 2,926 first-year GWh during 2015-2019. This amount equals 133 percent (2,926 GWh/2200 GWh = 133 percent) of five years of the Commission approved 2015 IRP annual energy savings, but only 75 percent of (2,926 GWh/3,900 GWh = 75 percent) of five years of the Company's proposed 2019 IRP average annual energy savings goal.).

(2,500 MW) fewer solar units.[100] Despite largely offsetting solar units, the increased energy efficiency did reduce overall CO_2 emissions during the planning period (2020 to 2034). This overall reduction in CO_2 emissions occurred because the increased energy efficiency reduces CO_2 emissions immediately while the CO_2 impact of fewer solar units is not experienced until the early 2030s.

Given that a Commission decision does not materially impact the supply-side resources selected for the expansion plan, does not impact the Company's least cost retirement plan, and does not impact the proposed expansion plan until later in the planning period, the Department recommends that the Commission take no action regarding the Company's proposed level of energy efficiency resources.

M. ASSESSMENT OF BIDDING PROCESS

1. Current Status

Xcel's current resource acquisition processes were established by the Commission[101] under Minnesota Statutes § 216B.2422 subd. 5, which states:

> **subd. 5. Bidding; exemption from certificate of need proceeding.**
> (a) A utility may select resources to meet its projected energy demand through a bidding process approved or established by the commission. A utility shall use the environmental cost estimates determined under subdivision 3 in evaluating bids submitted in a process established under this subdivision.
>
> (b) Notwithstanding any other provision of this section, if an electric power generating plant, as described in section 216B.2421, subdivision 2, clause (1), is selected in a bidding process approved or established by the commission, a certificate of need proceeding under section 216B.243 is not required.
>
> (c) A certificate of need proceeding is also not required for an electric power generating plant that has been selected in a bidding process approved or established by the commission, or such other selection process approved by the commission, to satisfy, in whole or in part, the wind power mandate of section 216B.2423 or the biomass mandate of section 216B.2424.

Originally, the Commission-approved bidding process was used when Xcel intended to acquire resources over 12 MW and for a duration of longer than five years.[102]

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[100] This result does not mean that energy efficiency is competitive with solar on a cost basis because the Department did not review the Company's energy efficiency cost inputs. It means that, if a higher level of savings is achieved, the impacts on the expansion plan largely involve off-setting solar units.
[101] See the Commission's May 31, 2006 *Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, subd. 5, and Requiring Compliance Filing* in Docket No. E002/RP-04-1752 (2006 Order).
[102] The 12 MW threshold was selected because supply resource additions less than 12 MW would not significantly contribute to future resource needs and because 12 MW was the lowest level for which a certificate approval process was required in the five states Xcel serves. The 5-year threshold was selected because 1) weather varies significantly in a 5-year horizon, 2) short term contracts are can be needed to meet reserve requirements, and 3) short term contracts can be

Note that Xcel's original (all-source) bidding process specifically included an exemption for capacity decisions involving existing generating units such as re-powering existing facilities, recapturing of capacity of existing facilities, capacity enhancements to existing facilities, and retention of the capacity of an existing facility (i.e., plant life extension or PPA extension). Neither the Department's nor Xcel's proposed modifications during the 2004 IRP addressed this exemption. The Commission's May 31, 2006 Order approved the two-track competitive resource acquisition process also did not discuss an exemption. Based upon the lack of discussion of such an exemption by the Department, Xcel, and the Commission's 2006 Order the Department concludes that the exemption for modifications to existing facilities was not carried forward by the Commission to the new, two-track process.

The most recent decision regarding Xcel's resource acquisition process is the Commission's January 11, 2017 *Order Approving Plan With Modifications and Establishing Requirements for Future Resource Plan Filings* (2017 Order) in Docket No. E002/RP-15-21 which stated at point 5:

> Concerning wind and solar resource acquisitions, Xcel:
>
> a. may use the modified Track 2 process for the acquisition of wind resources included in the five-year action plan, and for any additional solar, if needed, through 2021;
> b. shall, if Xcel intends to provide a bid for wind generation, acquire wind resources through the modified Track 2 process.
> c. shall file a contingency plan early in the process (preferably with the filing of the Company's self-build proposal) to address the potential for the bidding process to fail; and
> d. shall, in wind acquisition proceedings, describe how revenues from wind generation sold into the MISO market will be returned to Minnesota ratepayers, and provide an estimate of these revenues.
>
> The proper mix of purchased power and Company-owned resources shall be determined during the resource acquisition process.

The basics of the two-track process were established by the Commission in Docket No. E002/RP-04-1752. Track 1 is a bidding process run by Xcel. Track 1 is used to acquire resources when the Company *is not proposing a project*. Briefly, under Track 1 Xcel issues a Request for Proposals (RFP) to fill the identified need. Xcel then evaluates the bids received and submits resulting contracts for the projects that were selected to the Commission for approval.

Track 2 is a contested case process run by an administrative law judge. Currently, Track 2 is used to acquire resources when the Company *is proposing a non-wind/solar project*. Under Track 2 parties are invited to submit bids to fill all or part of the identified need. The bids are then sent to a contested case process, allowing parties to file testimony, followed by an evidentiary hearing, briefs, an Administrative Law Judge's recommendation, and ultimately a Commission determination.

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signed to reduce energy costs. The latter two reasons can have a short duration between the identification of the need and its realization. See the Department's July 8, 2016 comments in E002/RP-15-21.

Modified Track 2 was established by the 2017 Order and is now used to acquire resources when the Company *is proposing a wind or solar project through 2021*. Under Modified Track 2 parties are invited, via an RFP, to submit bids to fill all or part of the identified need. First, Xcel submits a proposal to the Commission the day before bids are due. Second, Xcel receives RFP bids and evaluates non-Company bids received under the RFP. Third, the Company submits a report evaluating the Company's proposal, the RFPs, and any contracts that were arrived at with winning bidders.

2. Track 1 Details

Xcel's August 28, 2006 *Compliance Filing* in Docket No. E002/RP-04-1752 described the Track 1 process as follows:

> This track will provide an independent auditor's report, use of a standard contract as the starting point in every bidding process and a contingency plan in the event of an unsuccessful bidding process.
>
> The main steps of the RFP process are:
>
> 1. The Commission issues Resource Plan Order
>   - Indicating the size, type, and timing of the resources Xcel Energy needs;
>   - Approving a standard contract to be used by independent power producers for the intermediate, peaking, and wind resources;
>   - Requiring Requests for Proposals ("RFP") for the intermediate, peaking, and wind needs identified in the Order;
>   - Requiring Xcel Energy to use an independent auditor to certify our process for obtaining and evaluating responses to the RFP is unbiased;
>   - Setting the timing for Xcel Energy to file its proposal for each separate resource; and
>   - Potentially setting the timing for completion of the resource acquisition process.
> 2. A targeted RFP for peaking, intermediate or renewable resources is issued (consistent with any timing specified in the Commission Order). The RFP will include the standard contract.
> 3. Bidders file their proposals with Xcel Energy pursuant to the RFP.
> 4. Xcel Energy files the contingency plan on the same date bids are due.
> 5. Xcel Energy makes selections and begins negotiations with the selected vendor.
> 6. Xcel Energy files the Independent Auditor certification, within 20 days of the selections. (Xcel Energy would not file a "selection report" or similar filing but would proceed directly to negotiations.)
> 7. Xcel Energy files for approval of a proposed power purchase agreement with the selected vendor within one year of the RFP issuance or other date specified by the Commission. The power purchase agreement petition must demonstrate that the proposed contract and its cost recovery would be reasonable. Alternatively, the Company files a statement of reasons why the negotiations have not been successfully completed. Under the alternative, the Commission could decide whether to have negotiations continue, to have the contingency plan pursued or consider some other option.

8. If the Commission approves the power purchase agreement the project would proceed to obtain any remaining permits, but a certificate of need would not be required per Minn. Stat. §216B.2422, subd. 5.
9. Upon receipt of all needed permits, the project proceeds with construction.

Other Details
Consistent with the desire to keep the process moving rapidly, the above process would eliminate pre-filing of the RFP with the Commission and interim selection reports that would require comments or otherwise delay the start of negotiation of the PPA This would not prevent the Department of Commerce review of the selections.
A timeline is provided in Appendix A If the process does not produce a petition for approval of a PPA following the one-year period, the Commission can determine whether to allow more time, or direct the Company to move forward with the contingency plan or seek additional information.

Standard Contract Approval
We are submitting a standard contract (Appendix C) for use in acquiring the peaking generating resource identified in the Resource Plan Order. Because this contract is to be approved prior to use, we have provided the standard contract only to the Commission, Department and Office of Attorney General for approval. The RFP will include the approved standard contract and will instruct bidders to specify a monetary value with each exception to the standard contract. Additionally, bidders will be instructed to identify exceptions they believe do not have a monetary value.

Independent Auditor Selection
Xcel Energy has maintained a list of independent auditors for use in the bidding process. We propose to maintain and select from this pool of approved auditors, as we have in the past.

3. Track 2 Details

Xcel's August 28, 2006 *Compliance Filing* in Docket No. E002/RP-04-1752 described the Track 2 process as follows:

> This track will provide a competitive resource acquisition process within the framework of a certificate of need-like process in which alternative proposals to Xcel Energy's preferred option are considered. This process will apply when Xcel Energy proposes to build its own generating facility and for all baseload resource needs.
>
> The main steps of this track are:
> a. The Commission issues a Resource Plan Order
> - Identifying the size, type, and timing of the resource needs;
> - Specifying the date to initiate the competitive process.
>
> b. On the date specified by the Commission, Xcel Energy submits its detailed filing for approval of its preferred resource (such as through a certificate of

need, a filing containing certificate of need quality information for an out-of-state resource, a petition for approval of a power purchase agreement for a baseload resource or combinations of such filings for resources.)

c. On the same date as Xcel Energy's submission described in Step 2, interested competitors (or alternative projects) provide their proposals in similar certificate of need-like detail. (Xcel Energy believes that pursuant to the process outlined in the Department comments adopted by the Order, these proposals are due the same date as Xcel Energy's.)
d. A contested case (certificate of need-like proceeding) is conducted, returning findings and recommendations to the Commission.
e. The Commission considers the developed record and issues its decision.
f. If the Commission selected (or preferred) option is not Xcel Energy's proposal, a four-month period for PPA negotiations is provided. If the Commission selected option is Xcel Energy' proposal, the Commission Order provides the requested (or Commission modified) approval
g. Following the four-month PPA negotiation period (or earlier as applicable) Xcel Energy petitions for approval of the PPA. If the parties are unable to reach a PPA, Xcel Energy shall file an explanation with the Commission and requested next steps (such as moving to another considered alternative proposal or the Company's original proposal.)
h. For an approved PPA, the project would proceed to obtain any remaining permits, but a certificate of need would not be required per Minn. Stat. §216B.2422, subd.5.
i. Upon receipt of all needed permits, the project proceeds with construction.

<u>Other Details</u>
The proposal content should be detailed enough so that the Commission can effectively initiate the contested case proceeding and so that no proposal is advantaged or disadvantaged by the level of information provided. For plants to be built in Minnesota the certificate of need rules would be required (except as noted below for alternative proposals). For out-of-state build options, similar quality data should be provided to allow a thorough and complete record development. For power purchase agreements, the proposal should include the level of detail provided historically in petitions for approval.

Alternative proposals would be granted the following exemptions:

- 7849.0240 subpart 2, part A: socially beneficial uses
- 7849.0250 subpart B: alternatives to the facility
- 7849.0250 subpart C (the portion applying to alternatives)
- 7849.0270: peak demand and annual consumption forecasts
- 7849.0280: system capacity
- 7849.0290: conservation programs
- 7849.0300: consequences of delay
- 7849.0340 (required within 7849.0310): information regarding the alternative of no facility

Alternative providers would be required to submit a list of supplementary data including:

- Developer experience and qualifications;
- Pricing of the proposal, including but not limited to:
  - The term;
  - In-service date;
  - Contract capacity;
  - Capacity payment;
  - Fixed operations and maintenance payment;
  - Variable operations and maintenance payment;
  - Fuel payment;
  - Tax related payments; and other costs;
- Scheduling provisions, including but not limited to:
  - Planned maintenance;
  - Expected minimum load;
  - Ramp rates; and
  - Limitations on operations;
- Discussion of the guaranteed performance factors, such as construction costs, unit completion, availability, and efficiency; and
- Any other key contract terms the provider requires.

4. Modified Track 2 Details

The Company's August 12, 2016 reply comments in Docket No. E002/RP-15-21 at pages 9-10 proposed the following steps for what is now referred to as Modified Track 2:

1. We would issue an RFP for wind project proposals.
2. The day before we receive responses to that RFP, we will submit our self-build project petition. This petition will contain an estimate of final costs for the project and other project details necessary to evaluate our proposal in accordance with the factors identified above.
3. After receiving bids in response to our RFP, we will evaluate the bids and select projects for contract negotiation that are in the best interest of our customers. We will evaluate the bids using a number of factors, such as:
    - Levelized cost;
    - Financial capability;
    - Project schedule;
    - Project design;
    - Project risks;
    - MISO queue position status;
    - Interconnection and network upgrades;
    - Energy production profile;
    - Site control;
    - Project output delivery plan;
    - Expected turbine availability;
    - Pricing options;
    - Project development milestones;

- Exceptions to standard contract terms and conditions; and
- Other relevant factors

Using these criteria, we will select projects that are in the best interest of our customers and will negotiate contracts with each of the developers.

4. We will then make a filing to the Commission that will include the contracts for projects selected from the RFP, as well as a comparison between those projects and our self-build proposal. We will include a ranking and bid data for all bids received in response to the RFP and an analysis of the factors identified above for all projects for which we conduct due diligence. Additionally, we will provide an independent third-party auditor report of our RFP process, which will review our evaluation of proposals and due diligence, as well as our selection of proposals for contract negotiation.

The Commission's 2017 Order approved this proposed process. Note that the Department's September 12, 2016 supplemental comments were concerned about the potential for the bidding process to fail. Therefore, the Department recommended:

> that the Company also file a contingency plan early in the process to address the potential for the bidding process to fail. This contingency plan is intended to ensure that all parties are clear on what to expect through the process. The Department recommends that the contingency plan be filed with the filing of the Company's self-build proposal (step 2 of Xcel's proposed process modifications).

The 2017 Order at point 5c included a requirement for a contingency plan.

5. Other Issues

On April 19, 2019 Xcel issued the Company's *Wind Resource Request For Proposals* (Wind RFP) for wind resources, see Docket No. E002/M-19-268. The Wind RFP stated:

> The Model PPA includes a Right of First Offer ("ROFO") that, subject to specific conditions, may be exercised by the Company. In addition, the Model PPA provides the Company with an option that specifies that the Company can purchase the facility at a specified time or times during the PPA term. The Company is requiring bidders to agree to the ROFO and purchase option as described in the Model PPA.

The Department does not object to the inclusion of a ROFO in PPAs. However, when negotiations occur regarding a ROFO both parties, Xcel and the seller, have an incentive to increase the price as much as possible. In recognition of this fact, basic accounting principles indicate that an asset was already placed in service and continues to operate under a PPA should have the purchase reflected at net book value and that acquisition adjustments should not be reflected in the purchase price. The Department's March 5, 2019 comments in Docket No. IP6949, E002/PA-18-702 clarified this by stating:

> The Department notes that traditionally, utility assets are recorded and recovered using the original cost of the asset and the related accumulated depreciation or resulting net book value of the asset. Acquisition adjustments are on top of the net book value and as a result require a significant finding of benefits to offset or justify this higher acquisition adjustment or premium before rate

> recovery is allowed, especially for utility assets that were already being used for public service (like MEC [Mankato Energy Center]). Use of net book value in rate base is consistent with Federal Energy Regulatory Commission requirements and Minnesota requirements under 216B.16, subd. 6…

Therefore, in order to allow a ROFO provision to be included in PPAs while simultaneously protecting ratepayers in a situation where both sides of the negotiations have an incentive to maximize costs, the Department recommends that the Commission cap any ROFO offer made by Xcel at net book value.

In addition to the ROFO provision, the Department notes that when issuing the RFP Xcel currently has wide latitude regarding what to include and exclude in the RFP process. The Department notes that, when the bidding process is used, the Company should be required to seek proposals for both PPA and build–operate–transfer (BOT) projects. Thus, the Department recommends that the Commission require any RFP issued by Xcel to include the option for both PPA and BOT proposals unless the Company can demonstrate why either a PPA or BOT proposal is not feasible.

Finally, Xcel's Petition at page 77 states "We believe the advancement of our grid, and technology generally, may take the form of less traditional DR, so with this Resource Plan we are requesting the flexibility to evaluate and pursue the required incremental DR through a variety of means and technologies over the coming years." The Department does not object to "flexibility to evaluate and pursue the required incremental DR." However, the Company did not request any particular flexibility that could be evaluated. Therefore, the Department recommends the Commission take no action on this request.

6. Notes on All-source Bidding

The Department notes that some interest in all-source bidding has been expressed in this proceeding. For example, see the agenda of the Commission's July 14, 2020 planning meeting. The Department does not support all-source bidding for several reasons. First, all-source bidding already failed twice in Minnesota.[103] The failure of Xcel's all-source bidding process is what led to the current, two-track bidding process. Second, the current process of conducting an IRP process followed by the two-track bidding process—targeted at acquiring the IRP determined needs—has worked well when the process is followed.

Third, if the IRP is not determining the size, type, and timing of resource needs, then the purpose of the IRP process becomes unclear. For example, the Commission might approve a particular expansion plan in an IRP. The Commission might also determine in that IRP that the Commission-approved plan meets the state's CO_2 goals. However, there is no reason to believe that Commission-approved plan will actually be followed in

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[103] Xcel's first all-source bidding process was initiated in 1999 (Docket No. E002/M-99-888). The final result was that two projects came on-line, an already existing PPA with Manitoba Hydro for 500 MW was extended and a PPA with Navitas Energy, LLC for 51 MW of wind from a new facility was approved by the Commission. Xcel's second all-source bidding process was initiated in 2001 (Docket No. E002/M-01-1618). Xcel's RFP released December 6, 2001 sought up to 1,000 MW with deliveries to begin between 2005 and 2009. On March 11, 2004 Xcel provided its *Status Report on Power Purchase Agreements and Resource Acquisition* (Status Report) indicating that, after two years, Xcel had signed PPAs with two projects and was still negotiating with two more projects. At the time of the Status Report, out of the 1,000 MW Xcel was seeking, Xcel had signed or was still negotiating about 398 MW. Some of the capacity deferred in the 1999 RFP was planned to be acquired in the second all-source bid; the amount deferred from the 1999 RFP was greater than the capacity acquired in the 2001 RFP. Thus, some of the capacity acquisition to be acquired in 1999 still had not been acquired five years and two resource acquisition processes later.

practice since the purpose of all-source bidding is to redo the IRP with actual bids rather than assumed costs. Thus, much of the analysis that currently takes place in the IRP would have to be done in the resource acquisition process.

Fourth, the purpose of all-source bidding is to attract a variety of bids for resources with differing size, type, and timing. For example, CT units, solar units, and wind units. However, CTs, solar, and wind cannot be compared on a levelized cost of energy (LCOE) basis. Thus, all-source bidding will require use of a CEM. If a utility receives only 20 bids, those 20 bids should be input to the CEM for simultaneous analysis (the purpose after all is to ascertain the best plan based on real bids). 20 bids result in 2^{20} combinations, or one million potential plans. That is before generic alternatives are fed in to cover years before and after the bids are available. That is why operating a CEM in an all-source framework is very difficult. To be at all feasible, the bids will have to be placed in pre-determined packages or analyzed sequentially, thus defeating the original purpose of the all-source bidding.

7. Department Recommendation

First, the Department recommends that the Commission determine that the Commission-approved bidding process applies in all instances where Xcel intends to acquire 100 MW of capacity for a duration longer than five years. This will ensure that the bidding process is limited to instances of significant potential investment and will not interfere in the Company's short-term operations.

Second, the Department recommends that the Commission approve the Track 1 bidding process, as outlined above, for resource acquisitions in which Xcel decides to not bid and that the Commission approve the Modified Track 2 bidding process, as outlined above, for resource acquisitions in which Xcel decides to bid. Both processes have proven successful in recent dockets[104] (when followed correctly) and provide significant ratepayer protections and thus warrant permanent approval.

In a recent bidding proceeding;[105] the Department identified issues regarding how well the independent auditor performed and whether Xcel provided the correct modeling files. For the independent auditor, while there is a potential incentive problem the Department is hopeful the issues were a one-time occurrence. In addition, the alternative approach—an independent evaluator—also has potential issues. As for the modeling files, that is beyond the scope of a competitive bidding process and it is not clear how a bidding process could solve Xcel's inability to identify and provide the correct data.

Third, in the Petition at page 21 Xcel requested flexibility in the size and timing (but not type) of resource acquisition. Xcel's response to Citizens Utility Board of Minnesota IR No. 24 clarifies that, when Xcel requested flexibility in resource acquisition, the Company:

> means that the magnitude and timing of procurement for any particular resource, or resources in aggregate, may not precisely match the amounts modeled in our Preferred Plan. This reflects an understanding that the market conditions we observe in a given year may not precisely match our modeling assumptions, and thus the capacity and pricing available in the market at the time we issue a solicitation may mean it would be more beneficial to ratepayers to move procurement timelines up or back accordingly."

[104] For example, see Docket Nos. E002/M-17-777 and E002/M-19-268.
[105] See Docket Nos. E002/M-20-620.

The Department agrees with Xcel that flexibility in the size and timing of resource acquisition is warranted. However, since this fact has long been recognized by the Commission, no specific language appears to be warranted. The Department expects all utilities to be aware of current market conditions and to prudently adapt to those conditions rather than blindly pursue a path pre-determined months or years before. As stated on page seven of the Department's May 1, 2017 Comments in Docket No. E002/M-16-777:

> Overall, a well-developed IRP provides the analytical basis for determinations in subsequent proceedings. In the past, when a utility's proposed resource acquisition has been consistent with the IRP analysis and subsequent Commission decision, no further resource-planning type analysis has been needed.[2] In other instances, when facts regarding the specific resources proposed by the utility have fallen outside of the analysis and Commission decision in the IRP, further resource-planning type analysis using the updated facts has been warranted. In essence, resource acquisition typically conforms with the Commission's most recent IRP order unless facts in the resource acquisition proceeding dictate that the action plan should change.[3] This approach appears to be consistent with the Commission's order in a recent resource acquisition proceeding:
> … while a resource plan is intended to plot a utility's course for the next 15 years, it is based on facts known as of a specific point in time. As more facts become known, circumstances change and utilities must adapt – even in the absence of a new resource plan order.[4]
>
> 2 Examples include Docket Nos. IP6838/CN-10-80 and E002/M-11-713 (Prairie Rose Wind); Docket No. E015/M-13-907 (Bison 4); and Docket Nos. E017/M-09-883 and E017/M-09-1484
> 3 A recent example is Xcel's acquisition of 750 MW of wind generation in Dockets E002/M-13-603 and E002/M-13-716. In this case Xcel's 2010 IRP called for the addition of 200 MW of wind. However, Xcel subsequently found the cost of wind generation was below the cost evaluated in the IRP. Additional analysis with updated costs was performed by Xcel and the DOC.
> 4 See the Commission's December 13, 2013 *Order Approving Acquisitions with Conditions* in Docket Nos. E002/M-13-603 and E002/M-13-716.

Fourth, the Department notes that while Xcel used a combustion turbine as a proxy for a peaking resource the Company made it clear throughout this proceeding that the Company is neutral as to the actual technology that would be acquired to fill any future needs for peaking resources.[106] The Department agrees with Xcel on this approach. Thus, the Department recommends that the Commission require that any RFP documents for peaking resources issued by Xcel be technology neutral.

Finally, the Department recommends that the Commission cap any ROFO offer made by Xcel at net book value and require any RFP to include the option for both PPAs and BOTs unless the Company can demonstrate why either a PPA or BOT proposal is not feasible.

[106] For example, on page 106 of the Petition Xcel states that the Company inserted "CT additions as a proxy placeholder…we expect the need will be met by a combination of firm dispatchable resource options. These may include battery storage, pumped hydro, DR, natural gas, and/or others."

N. ASSESSMENT OF VARIOUS POLICIES

1. 50 Percent and 75 Percent Renewables/DSM

Minnesota Statutes §216B.2422, subd. 2 (c) states:

> As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources.

To analyze the Department's preferred plan under this consideration, the Department added the total energy production between 2020 and 2034 (the planning period) from generic, new wind and solar units, new energy efficiency programs, distributed solar units[107], the generic CT units, and the Sherco CC unit.[108] Note that the committed but not on-line in 2020 Sherco CC unit was included but energy from committed but not on-in 2020 line solar and/or wind units (such as Dakota Range III and Elk Creek) were not included in the analysis. Furthermore, the generic CT units are merely a placeholder. The specific technology may or may not be natural gas fueled. That will be determined in the future. For purposes of this analysis it is assumed that the CT units are ultimately selected to fill the peaking need.

The result of this analysis is summarized in Table 24 below. The Department's preferred plan consists of 75 percent of new energy coming from renewable and energy efficiency when optimized. Therefore, no further analysis was performed for this criterion.

Table 24: Department Preferred Plan (Percent Renewables/DSM)

Category	GWh	Percent
Utility-Scale Solar	45,311.84	24%
Distributed Solar	11,269.67	6%
Utility Energy Efficiency	83,302.42	45%
CT/CC units	45,777.95	25%
TOTAL	185,661.87	100%

The Department performed the same analysis using Strategist outputs from Xcel's Scenario 9. The result of this analysis is summarized in Table 25 below. Xcel's preferred plan consists of 81 percent of new energy coming from renewable and energy efficiency when optimized.[109] Therefore, no further analysis was performed for this criterion.

[107] These are the units "NM_1-20" representing net metering solar and "SES_CSG" representing community solar gardens. For these units the level of production in 2019 was removed from each years' production to arrive at the total new renewable energy that year.
[108] Note that the percent renewables and DSM would rise if the end effects years (2035 to 2045) were included.
[109] Again, the percent renewables and DSM would rise if the end effects years (2035 to 2045) were included.

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Table 25: Xcel's Preferred Plan (Percent Renewables/DSM)

Category	GWh	Percent
Utility-Scale Wind and Solar	82,205.62	38%
Distributed Solar	11,269.67	5%
Utility Energy Efficiency	83,302.42	38%
CT/CC units	42,242.15	19%
TOTAL	219,019.86	100%

In summary, the preferred plan of both the Department and Xcel meet this criterion.

2. Renewable Energy Standard

a. Background

Minnesota Statutes § 216B.1691, subd. 2 (b) establishes the renewable energy standard (RES) that Xcel:

> Must generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies by the end of the year indicated
>
> - 2010 15 percent
> - 2012 18 percent
> - 2016 25 percent
> - 2020 30 percent
>
> Of the 30 percent in 2020, at least 25 percent must be generated by solar energy or wind energy conversion systems and the remaining five percent by other eligible energy technology. Of the 25 percent that must be generated by wind or solar, no more than one percent may be solar generated and the remaining 24 percent or greater must be wind generated.

An eligible energy technology is defined by Minnesota Statutes § 216B.1691, subd. 1 as an energy technology that:

> Generates electricity from the following energy sources:
> (1) solar;
> (2) wind;
> (3) hydroelectric with a capacity of less than 100 megawatts;
> (4) hydrogen, provided that after January 1, 2010, the hydrogen must be generated from the resources listed in this clause; or
> (5) biomass, which includes without limitation, landfill gas, an anaerobic digester system, and an energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel.

Minnesota Statutes § 216B.1691 subd. 2f requires that, in addition to the RES obligation, a publicly owned utility obtain at least 1.5 percent of its Minnesota retail sales from solar energy by the end of 2020. For Xcel, of that 1.5 percent, at least ten percent must be from solar facilities of 40 kW or less. The SES statute excludes certain retail sales to iron mining, paper and wood products manufacturers from the calculation of the SES requirement.

b. Renewable Energy Standard Compliance

The Department reviews historical compliance with the RES statute in a biennual report to the legislature. The most recent report was filed May 30, 2019 in Docket No. E999/M-18-78. This report concluded that "all of the utilities subject to the Minnesota RES have demonstrated compliance with the 2017 RES requirements." The Department also reviews compliance with the RES statute in the annual periodic reporting docket (most recently, Docket No. E999/PR-20-12).

Regarding future compliance the Department notes that the Company's preferred plan results in annual renewable energy production equal to between 35 percent and 80 percent of system-wide sales.[110] The overall RES Statute requirement is 30 percent; thus, the Company's proposed plan will result in compliance with the overall required renewable percentage. The Department did not investigate compliance with the various RES sub-categories; Xcel's compliance will be reviewed in other proceedings. The Department's proposed plan results in annual renewable energy production equal to between 35 percent and 76 percent of system-wide energy sales. Therefore, the Department's proposed plan will result in compliance with the overall required renewable percentage. .

c. Solar Energy Standard Compliance

The Department reviews compliance with the SES statute in a biennial report to the legislature. The most recent report was filed May 30, 2019 in Docket No. E999/M-18-78. This report did not make a conclusion regarding SES compliance since the first year for compliance is 2020.

Regarding future compliance the Department notes that the Company's proposed plan results in annual solar energy production equal to between one percent and 29 percent of system-wide sales—excluding distributed solar. The overall SES statute requirement is 1.5 percent; thus, compliance in the early years may depend on a variety of factors such as actual energy sales, actual energy production, treatment of distributed solar, banking of solar credits, and so on. However, after the early-2020s the Company's proposed plan will result in compliance with the overall SES percentage as annual solar generation greatly exceeds 1.5 percent. The Department's proposed plan results in annual solar energy production equal to between one percent and 33 percent of system-wide sales. Therefore, the Department's proposed plan also will result in compliance with the overall SES percentage after the mid-2020s. As with the RES, the Department did not investigate compliance with the various SES sub-categories; Xcel's compliance will be reviewed in other proceedings.

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[110] Data taken from the Strategist outputs associated with Xcel's Scenario 9, base case conditions.

3. Minnesota Greenhouse Gas Emissions Reduction Goal

Minnesota Statutes § 216H.02, subd. 1 states that:

> It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050. The levels shall be reviewed based on the climate change action plan study.

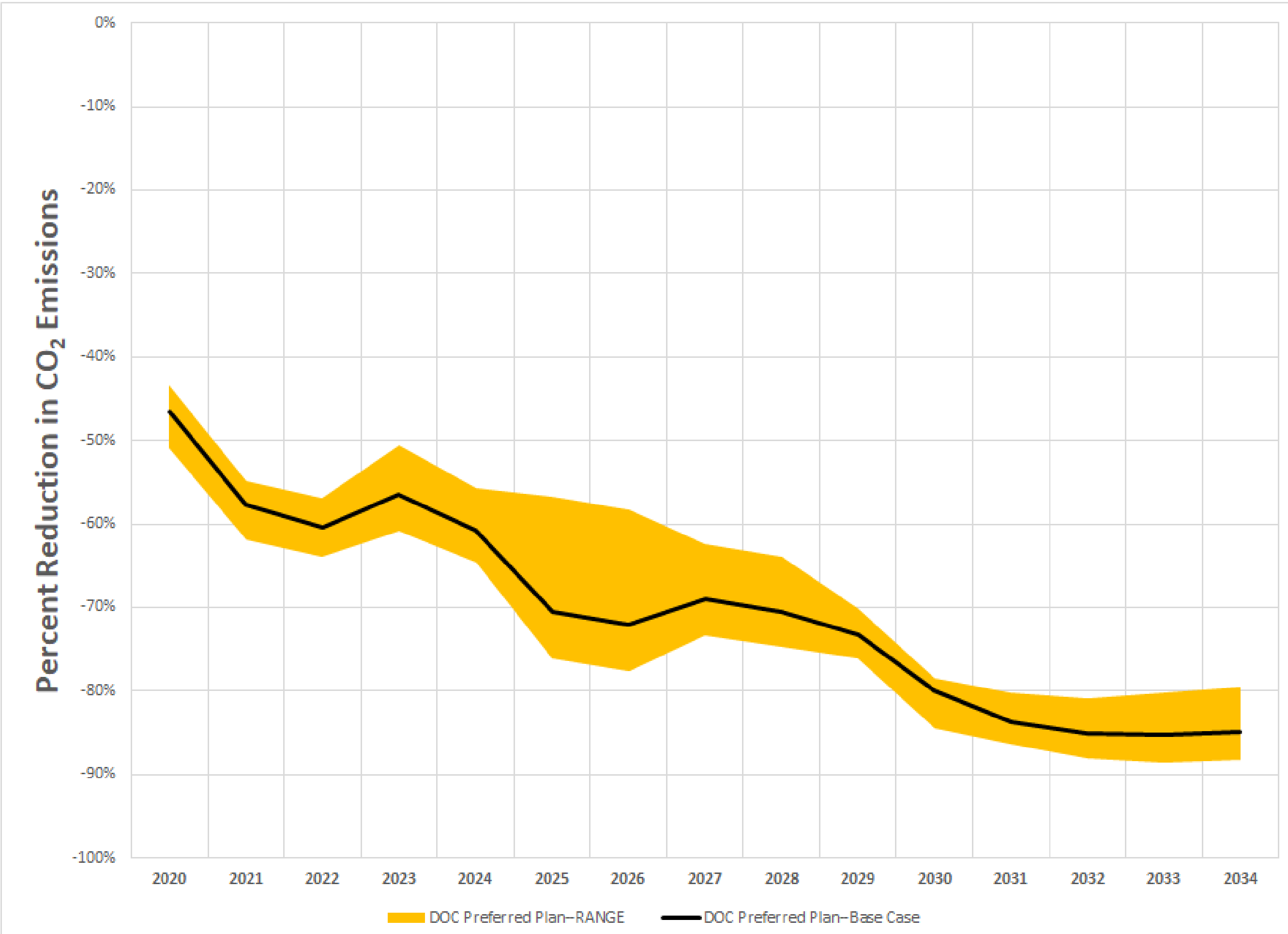
Xcel's reply to CEO IR No. 7 explained how Xcel calculated emissions:

> Note that the total provided for each year represents CO_2 from electricity serving our customers. We include CO_2 from short-term MISO market purchases, but exclude CO_2 attributable to short-term sales into the MISO market, since this energy is sold to others for resale to their end-use customers; including it in our reporting would result in double-counting if the purchasers account for it in their reporting. It would also overstate the total CO_2 our customers are responsible for, if we were to include CO_2 from MISO market purchases but not deduct CO_2 from MISO market sales.

The Department agrees with Xcel's logic that including imports but excluding exports would result in double-counting if the purchasers account for CO_2 emissions in their reporting. Therefore, for purposes of this docket the Department calculated CO_2 emissions in a manner similar to Xcel—the total provided for each year represents CO_2 from electricity serving customers. The Department's data includes an addition for CO_2 from Spot Market purchases and a subtraction for CO_2 for Spot Market sales.[111] Xcel's response to CEO IR No. 7 stated that Xcel's emissions were 28,055,690 tons in 2005, calculated to be consistent with the import/export treatment. Figure 11 shows CO_2 emissions from the Department's preferred plan calculated using the import/export adjustment method. Figure 11 shows that the Department's preferred plan should meet the state's 2050 emissions reduction goal by the early 2030s.

[111] These Spot Market emissions adjustments are done using an average emission factor. It would be better to use marginal emissions, but that data is not available.

Figure 11: Greenhouse Gas Reduction
(Reduction in tons attributable to Xcel customers)



III. DEPARTMENT RECOMMENDATIONS

Regarding forecasting, the Department recommends that the Commission order Xcel to file and use a forecast from an independent consultant in any future regulatory proceedings. Additionally, the use of an independently derived forecast should continue until such time as Xcel can demonstrate in a separate proceeding that the Company has identified the source(s) of the bias in Company prepared forecasts and has identified, explained, and taken steps that can reasonably be expected to address the identified issues.

Regarding the proposed Sherco CC unit, the Department recommends the Commission not make a determination regarding reasonable and prudently incurred costs in this proceeding. Since Xcel has not requested approval of a revision of the Sherco CC unit included in the last IRP, the Department also recommends the Commission not approve any revision to the Sherco CC unit included in E002/RP-15-21.

Regarding the baseload study, the Department recommends the Commission order Xcel to:

- retire King, Sherco unit 3, and Monticello on the early dates;
- proceed assuming Prairie Island will undergo a license extension, and re-study the retirement date in the next resource plan;
- acquire solar resources as specified in Table 13 above;
- proceed assuming the Company will not add wind resources during the planning period; and
- proceed assuming the Company will not add capacity resources during the planning period.

Regarding energy efficiency, the Department recommends that the Commission take no action regarding the Company's proposed level of energy efficiency resources.

Regarding resource acquisition, the Department recommends that the Commission:

- approve the Track 1 bidding process, as outlined above, for resource acquisitions in which Xcel determines to not bid;
- approve the Modified Track 2 bidding process, as outlined above, for resource acquisitions in which Xcel determines to bid;
- require that any RFP documents for peaking resources issued by Xcel be technology neutral;
- cap any ROFO offer made by Xcel at net book value;
- require any RFP issued by Xcel to include the option for both PPAs and BOTs unless the Company can demonstrate why either a PPA or BOT proposal is not feasible; and
- take no action on the request for "flexibility to evaluate and pursue the required incremental DR."

/ar

Docket No. E002/RP- 19-368

Attachment 1

Select Strategist Outputs--Standard Assumptions

Select Strategist Outputs--Standard Assumptions

Scenario 101 KINN_SHEN_MONN_PRAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,365	194,765	-	-	-	-	-	9	-	-	1	195,896
Mid Externalities, No CO_2 Internal Cost	$ 40,785	232,616	-	-	-	-	-	9	-	-	1	179,028
High Externalities, No CO_2 Internal Cost	$ 44,957	215,813	-	-	1	-	-	11	-	-	-	212,447
High Externalities, Use CO_2 Internal Cost	$ 39,269	175,595	-	-	2	-	-	10	-	-	-	255,577
Low Externalities, No CO_2 Internal Cost	$ 36,495	238,000	-	-	-	-	-	9	-	-	1	168,772
Low Externalities, Use CO_2 Internal Cost	$ 35,050	225,309	-	-	-	-	-	9	-	-	1	161,491
No Externalities, Use CO_2 Internal Cost	$ 33,818	238,690	-	-	-	-	-	7	-	-	2	168,409
No Externalities, No CO_2 Internal Cost	$ 33,818	238,690	-	-	-	-	-	7	-	-	2	168,409
Low Solar Price	$ 36,785	203,095	-	-	-	-	-	9	-	-	1	166,125
High Solar Price	$ 37,806	192,332	-	-	2	-	-	5	-	-	2	224,156
Low Wind Price	$ 36,869	171,286	-	-	5	-	-	7	-	-	-	281,070
High Wind Price	$ 37,375	205,009	-	-	-	-	-	9	-	-	1	162,222
Low Forecast	$ 36,387	186,973	-	-	-	-	-	10	-	-	-	205,980
High Forecast	$ 40,103	213,725	-	-	-	-	2	11	-	-	4	149,793
Low Coal Cost	$ 37,291	194,765	-	-	-	-	-	9	-	-	1	195,896
High Coal Cost	$ 37,439	194,765	-	-	-	-	-	9	-	-	1	195,896
Low Gas Price	$ 36,779	211,570	-	-	-	-	-	1	-	-	5	(70,575)
High Gas Price	$ 37,397	169,207	-	-	4	-	-	8	-	-	-	304,937
Low Nuke Cost	$ 36,873	194,765	-	-	-	-	-	9	-	-	1	195,896
High Nuke Cost	$ 37,858	194,765	-	-	-	-	-	9	-	-	1	195,896
High Market Price	$ 37,221	196,386	-	-	1	-	-	11	-	-	-	316,074
Low Market Price	$ 37,162	193,897	-	-	-	-	-	9	-	-	1	50,797
Low Market Capacity	$ 37,424	205,957	-	-	-	-	-	9	-	-	1	93,549
No Market	$ 37,748	201,927	-	-	-	-	-	5	-	-	3	-

Department Attachment 1
Select Strategist Outputs--Standard Assumptions

Scenario 102 KINE_SHEN_MONN_P RAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,242	203,801	-	-	-	-	-	12	-	-	1	154,084
Mid Externalities, No CO_2 Internal Cost	$ 40,154	214,704	-	-	-	-	-	12	-	-	1	171,949
High Externalities, No CO_2 Internal Cost	$ 44,013	211,948	-	-	-	-	-	12	-	-	1	177,011
High Externalities, Use CO_2 Internal Cost	$ 39,124	172,186	-	-	2	-	-	11	-	-	1	260,251
Low Externalities, No CO_2 Internal Cost	$ 36,219	221,364	-	-	-	-	-	10	-	-	2	159,301
Low Externalities, Use CO_2 Internal Cost	$ 34,978	214,872	-	-	-	-	-	10	-	-	2	156,678
No Externalities, Use CO_2 Internal Cost	$ 33,775	222,972	-	-	-	-	-	8	-	-	3	157,956
No Externalities, No CO_2 Internal Cost	$ 33,775	222,972	-	-	-	-	-	8	-	-	3	157,956
Low Solar Price	$ 36,585	195,766	-	-	-	-	-	12	-	-	1	170,859
High Solar Price	$ 37,731	184,798	-	-	2	-	-	6	-	-	3	237,882
Low Wind Price	$ 36,759	167,272	-	-	4	-	-	7	-	-	2	283,763
High Wind Price	$ 37,242	203,801	-	-	-	-	-	12	-	-	1	154,084
Low Forecast	$ 36,261	180,972	-	-	-	-	-	11	-	-	1	214,049
High Forecast	$ 40,038	201,192	-	-	-	-	5	9	-	-	5	165,753
Low Coal Cost	$ 37,190	203,801	-	-	-	-	-	12	-	-	1	154,084
High Coal Cost	$ 37,293	203,801	-	-	-	-	-	12	-	-	1	154,084
Low Gas Price	$ 36,694	213,653	-	-	-	-	-	2	-	-	6	(76,938)
High Gas Price	$ 37,261	169,630	-	-	4	-	-	11	-	-	-	290,766
Low Nuke Cost	$ 36,749	203,801	-	-	-	-	-	12	-	-	1	154,084
High Nuke Cost	$ 37,734	203,801	-	-	-	-	-	12	-	-	1	154,084
High Market Price	$ 37,094	194,066	-	-	1	-	-	9	-	-	2	302,776
Low Market Price	$ 37,044	190,623	-	-	-	-	-	10	-	-	2	56,009
Low Market Capacity	$ 37,331	199,305	-	-	-	-	-	8	-	-	3	98,526
No Market	$ 37,672	195,334	-	-	-	-	-	6	-	-	4	-

Select Strategist Outputs--Standard Assumptions

Scenario 103 KINN_SHEE_MONN_P RAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,228	183,995	-	-	-	-	-	13	-	-	1	192,019
Mid Externalities, No CO_2 Internal Cost	$ 40,244	217,601	-	-	-	-	-	13	-	-	1	171,241
High Externalities, No CO_2 Internal Cost	$ 44,072	201,815	-	-	1	-	-	14	-	-	-	204,102
High Externalities, Use CO_2 Internal Cost	$ 39,049	167,349	-	-	2	-	-	11	-	-	1	252,588
Low Externalities, No CO_2 Internal Cost	$ 36,327	223,754	-	-	-	-	-	10	-	-	2	160,418
Low Externalities, Use CO_2 Internal Cost	$ 35,092	212,078	-	-	-	-	-	10	-	-	2	153,457
No Externalities, Use CO_2 Internal Cost	$ 33,903	224,901	-	-	-	-	-	10	-	-	2	159,871
No Externalities, No CO_2 Internal Cost	$ 33,903	224,901	-	-	-	-	-	10	-	-	2	159,871
Low Solar Price	$ 36,581	192,325	-	-	-	-	-	13	-	-	1	162,248
High Solar Price	$ 37,708	186,521	-	-	1	-	-	5	-	-	4	207,629
Low Wind Price	$ 36,738	162,366	-	-	5	-	-	6	-	-	2	279,084
High Wind Price	$ 37,235	199,891	-	-	-	-	-	10	-	-	2	146,580
Low Forecast	$ 36,248	179,222	-	-	-	-	-	11	-	-	1	199,714
High Forecast	$ 40,003	205,789	-	-	-	-	2	12	-	-	5	141,360
Low Coal Cost	$ 37,162	183,995	-	-	-	-	-	13	-	-	1	192,019
High Coal Cost	$ 37,294	183,995	-	-	-	-	-	13	-	-	1	192,019
Low Gas Price	$ 36,646	203,564	-	-	-	-	-	2	-	-	6	(75,072)
High Gas Price	$ 37,220	158,415	-	-	4	-	-	11	-	-	-	301,098
Low Nuke Cost	$ 36,735	183,995	-	-	-	-	-	13	-	-	1	192,019
High Nuke Cost	$ 37,721	183,995	-	-	-	-	-	13	-	-	1	192,019
High Market Price	$ 37,088	186,428	-	-	1	-	-	12	-	-	1	310,237
Low Market Price	$ 37,028	184,806	-	-	-	-	-	10	-	-	2	48,503
Low Market Capacity	$ 37,311	198,006	-	-	-	-	-	8	-	-	3	88,480
No Market	$ 37,638	194,790	-	-	-	-	-	6	-	-	4	-

Select Strategist Outputs--Standard Assumptions

Scenario 104 KINN_SHEN_MONE_P RAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,261	199,616	-	-	-	-	-	9	-	-	1	179,430
Mid Externalities, No CO_2 Internal Cost	$ 40,653	238,309	-	-	-	-	-	9	-	-	1	163,796
High Externalities, No CO_2 Internal Cost	$ 44,874	221,505	-	-	1	-	-	11	-	-	-	197,215
High Externalities, Use CO_2 Internal Cost	$ 39,230	180,309	-	-	2	-	-	10	-	-	-	239,159
Low Externalities, No CO_2 Internal Cost	$ 36,313	243,692	-	-	-	-	-	9	-	-	1	153,540
Low Externalities, Use CO_2 Internal Cost	$ 34,873	230,750	-	-	-	-	-	9	-	-	1	145,725
No Externalities, Use CO_2 Internal Cost	$ 33,606	244,382	-	-	-	-	-	7	-	-	2	153,177
No Externalities, No CO_2 Internal Cost	$ 33,606	244,382	-	-	-	-	-	7	-	-	2	153,177
Low Solar Price	$ 36,681	207,946	-	-	-	-	-	9	-	-	1	149,659
High Solar Price	$ 37,701	197,183	-	-	2	-	-	5	-	-	2	207,690
Low Wind Price	$ 36,764	176,136	-	-	5	-	-	7	-	-	-	264,602
High Wind Price	$ 37,270	209,860	-	-	-	-	-	9	-	-	1	145,755
Low Forecast	$ 36,275	191,658	-	-	-	-	-	10	-	-	-	190,191
High Forecast	$ 40,127	217,902	-	-	-	-	4	9	-	1	3	137,728
Low Coal Cost	$ 37,187	199,616	-	-	-	-	-	9	-	-	1	179,430
High Coal Cost	$ 37,335	199,616	-	-	-	-	-	9	-	-	1	179,430
Low Gas Price	$ 36,544	217,303	-	-	-	-	-	1	-	-	5	(91,041)
High Gas Price	$ 37,372	174,220	-	-	4	-	-	8	-	-	-	288,904
Low Nuke Cost	$ 36,823	199,616	-	-	-	-	-	9	-	-	1	179,430
High Nuke Cost	$ 37,699	199,616	-	-	-	-	-	9	-	-	1	179,430
High Market Price	$ 37,157	201,666	-	-	1	-	-	11	-	-	-	302,322
Low Market Price	$ 37,013	198,948	-	-	-	-	-	9	-	-	1	31,522
Low Market Capacity	$ 37,269	210,477	-	-	-	-	-	9	-	-	1	84,278
No Market	$ 37,519	205,752	-	-	-	-	-	5	-	-	3	-

Select Strategist Outputs--Standard Assumptions

Scenario 105 KINN_SHEN_MONX_PRAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,534	187,014	-	-	-	-	-	7	-	-	-	215,203
Mid Externalities, No CO_2 Internal Cost	$ 40,984	221,262	-	-	-	-	-	7	-	-	-	204,068
High Externalities, No CO_2 Internal Cost	$ 45,169	218,712	-	-	-	-	-	7	-	-	-	208,194
High Externalities, Use CO_2 Internal Cost	$ 39,397	172,376	-	-	1	-	-	6	-	-	-	268,204
Low Externalities, No CO_2 Internal Cost	$ 36,756	225,298	-	-	-	-	-	7	-	-	-	196,259
Low Externalities, Use CO_2 Internal Cost	$ 35,301	214,577	-	-	-	-	-	7	-	-	-	188,425
No Externalities, Use CO_2 Internal Cost	$ 34,106	228,131	-	-	-	-	-	5	-	-	1	195,173
No Externalities, No CO_2 Internal Cost	$ 34,106	228,131	-	-	-	-	-	5	-	-	1	195,173
Low Solar Price	$ 37,026	191,442	-	-	-	-	-	7	-	-	-	194,295
High Solar Price	$ 37,910	187,128	-	-	2	-	-	3	-	-	1	239,610
Low Wind Price	$ 37,166	171,908	-	-	2	-	-	3	-	-	1	286,660
High Wind Price	$ 37,544	194,518	-	-	-	-	-	7	-	-	-	189,940
Low Forecast	$ 36,583	180,261	-	-	-	-	-	6	-	-	-	228,731
High Forecast	$ 40,215	202,866	-	-	-	-	2	9	-	-	3	175,269
Low Coal Cost	$ 37,460	187,014	-	-	-	-	-	7	-	-	-	215,203
High Coal Cost	$ 37,608	187,014	-	-	-	-	-	7	-	-	-	215,203
Low Gas Price	$ 37,167	196,900	-	-	-	-	-	1	-	-	3	(38,530)
High Gas Price	$ 37,517	173,411	-	-	1	-	-	6	-	-	-	300,543
Low Nuke Cost	$ 36,927	187,014	-	-	-	-	-	7	-	-	-	215,203
High Nuke Cost	$ 38,141	187,014	-	-	-	-	-	7	-	-	-	215,203
High Market Price	$ 37,344	196,233	-	-	-	-	-	7	-	-	-	310,348
Low Market Price	$ 37,394	182,570	-	-	-	-	-	7	-	-	-	80,078
Low Market Capacity	$ 37,592	196,593	-	-	-	-	-	5	-	-	1	110,190
No Market	$ 37,932	191,992	-	-	-	-	-	3	-	-	2	-

Select Strategist Outputs--Standard Assumptions

Scenario 106 KINN_SHEN_MONN_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,251	208,238	-	-	-	-	1	11	-	-	-	146,180
Mid Externalities, No CO_2 Internal Cost	$ 40,491	247,392	-	-	-	-	1	11	-	-	-	132,037
High Externalities, No CO_2 Internal Cost	$ 44,791	245,451	-	-	-	-	1	11	-	-	-	135,939
High Externalities, Use CO_2 Internal Cost	$ 39,332	187,645	-	-	3	-	1	8	-	-	-	213,089
Low Externalities, No CO_2 Internal Cost	$ 36,152	252,775	-	-	-	-	1	11	-	-	-	121,781
Low Externalities, Use CO_2 Internal Cost	$ 34,760	241,866	-	-	-	-	1	9	-	-	1	112,767
No Externalities, Use CO_2 Internal Cost	$ 33,434	255,525	-	-	-	-	1	9	-	-	1	121,557
No Externalities, No CO_2 Internal Cost	$ 33,434	255,525	-	-	-	-	1	9	-	-	1	121,557
Low Solar Price	$ 36,539	216,568	-	-	-	-	1	11	-	-	-	116,409
High Solar Price	$ 37,816	206,512	-	-	2	-	1	5	-	-	2	178,269
Low Wind Price	$ 36,707	178,686	-	1	4	-	-	8	-	-	-	250,625
High Wind Price	$ 37,260	218,482	-	-	-	-	1	11	-	-	-	112,505
Low Forecast	$ 36,236	203,846	-	-	-	-	-	10	-	-	-	151,593
High Forecast	$ 40,247	228,595	-	-	-	-	6	9	-	1	2	104,943
Low Coal Cost	$ 37,177	208,238	-	-	-	-	1	11	-	-	-	146,180
High Coal Cost	$ 37,325	208,238	-	-	-	-	1	11	-	-	-	146,180
Low Gas Price	$ 36,301	233,416	-	-	-	-	1	2	-	-	4	(132,937)
High Gas Price	$ 37,487	181,867	-	-	4	-	1	8	-	-	-	263,111
Low Nuke Cost	$ 36,952	208,238	-	-	-	-	1	11	-	-	-	146,180
High Nuke Cost	$ 37,551	208,238	-	-	-	-	1	11	-	-	-	146,180
High Market Price	$ 37,233	211,704	-	-	1	-	1	10	-	-	-	271,466
Low Market Price	$ 36,923	209,631	-	-	-	-	1	11	-	-	-	(2,170)
Low Market Capacity	$ 37,263	221,002	-	-	-	-	1	9	-	-	1	59,681
No Market	$ 37,462	221,178	-	-	-	-	1	4	-	-	3	-

Select Strategist Outputs--Standard Assumptions

Scenario 107 KINN_SHEN_MONN_PRAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,160	184,088	-	-	-	-	-	5	-	-	-	218,709
Mid Externalities, No CO_2 Internal Cost	$ 40,664	214,336	-	-	-	-	-	5	-	-	-	224,897
High Externalities, No CO_2 Internal Cost	$ 44,890	214,336	-	-	-	-	-	5	-	-	-	224,897
High Externalities, Use CO_2 Internal Cost	$ 38,998	169,069	-	-	2	-	-	3	-	-	-	273,587
Low Externalities, No CO_2 Internal Cost	$ 36,437	214,336	-	-	-	-	-	5	-	-	-	224,897
Low Externalities, Use CO_2 Internal Cost	$ 34,971	204,247	-	-	-	-	-	5	-	-	-	214,390
No Externalities, Use CO_2 Internal Cost	$ 33,797	219,163	-	-	-	-	-	5	-	-	-	220,966
No Externalities, No CO_2 Internal Cost	$ 33,797	219,163	-	-	-	-	-	5	-	-	-	220,966
Low Solar Price	$ 36,708	183,654	-	-	-	-	-	5	-	-	-	219,567
High Solar Price	$ 37,519	177,245	-	-	2	-	-	3	-	-	-	272,465
Low Wind Price	$ 36,791	165,429	-	-	2	-	-	3	-	-	-	302,109
High Wind Price	$ 37,165	186,438	-	-	-	-	-	5	-	-	-	210,253
Low Forecast	$ 36,225	177,562	-	-	-	-	-	3	-	-	-	238,580
High Forecast	$ 39,857	200,512	-	-	-	-	2	10	-	-	1	179,699
Low Coal Cost	$ 37,086	184,088	-	-	-	-	-	5	-	-	-	218,709
High Coal Cost	$ 37,234	184,088	-	-	-	-	-	5	-	-	-	218,709
Low Gas Price	$ 36,895	189,461	-	-	-	-	-	1	-	-	2	(34,817)
High Gas Price	$ 37,050	167,480	-	-	2	-	-	3	-	-	-	316,011
Low Nuke Cost	$ 36,529	184,088	-	-	-	-	-	5	-	-	-	218,709
High Nuke Cost	$ 37,790	184,088	-	-	-	-	-	5	-	-	-	218,709
High Market Price	$ 36,946	190,397	-	-	1	-	-	4	-	-	-	330,924
Low Market Price	$ 37,060	169,141	-	-	-	-	-	5	-	-	-	112,851
Low Market Capacity	$ 37,193	187,737	-	-	-	-	-	5	-	-	-	126,436
No Market	$ 37,458	191,348	-	-	-	-	-	3	-	-	1	-

Select Strategist Outputs--Standard Assumptions

Scenario 108 KINE_SHEN_MONE_P RAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,146	208,356	-	-	-	-	1	11	-	-	1	138,511
Mid Externalities, No CO_2 Internal Cost	$ 40,024	219,851	-	-	-	-	1	11	-	-	1	157,175
High Externalities, No CO_2 Internal Cost	$ 43,925	217,095	-	-	-	-	1	11	-	-	1	162,237
High Externalities, Use CO_2 Internal Cost	$ 39,090	176,644	-	-	2	-	1	10	-	-	1	244,784
Low Externalities, No CO_2 Internal Cost	$ 36,047	226,511	-	-	-	-	1	9	-	-	2	144,527
Low Externalities, Use CO_2 Internal Cost	$ 34,813	219,875	-	-	-	-	1	9	-	-	2	141,639
No Externalities, Use CO_2 Internal Cost	$ 33,579	228,119	-	-	-	-	1	7	-	-	3	143,182
No Externalities, No CO_2 Internal Cost	$ 33,579	228,119	-	-	-	-	1	7	-	-	3	143,182
Low Solar Price	$ 36,483	200,320	-	-	-	-	1	11	-	-	1	155,287
High Solar Price	$ 37,640	189,352	-	-	2	-	1	5	-	-	3	222,307
Low Wind Price	$ 36,663	171,827	-	-	4	-	1	6	-	-	2	268,189
High Wind Price	$ 37,146	208,356	-	-	-	-	1	11	-	-	1	138,511
Low Forecast	$ 36,153	185,620	-	-	-	-	-	11	-	-	1	198,166
High Forecast	$ 40,064	206,982	-	-	-	-	6	8	-	1	4	153,187
Low Coal Cost	$ 37,095	208,356	-	-	-	-	1	11	-	-	1	138,511
High Coal Cost	$ 37,197	208,356	-	-	-	-	1	11	-	-	1	138,511
Low Gas Price	$ 36,474	219,040	-	-	-	-	1	1	-	-	6	(96,228)
High Gas Price	$ 37,239	174,296	-	-	4	-	1	10	-	-	-	275,505
Low Nuke Cost	$ 36,708	208,356	-	-	-	-	1	11	-	-	1	138,511
High Nuke Cost	$ 37,583	208,356	-	-	-	-	1	11	-	-	1	138,511
High Market Price	$ 37,036	198,959	-	-	1	-	1	8	-	-	2	289,673
Low Market Price	$ 36,907	195,392	-	-	-	-	1	9	-	-	2	37,813
Low Market Capacity	$ 37,185	203,551	-	-	-	-	1	7	-	-	3	89,772
No Market	$ 37,457	198,918	-	-	-	-	1	5	-	-	4	-

Select Strategist Outputs--Standard Assumptions

Scenario 109 KINE_SHEN_MONX_P RAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,393	185,283	-	-	-	-	-	8	-	-	1	212,531
Mid Externalities, No CO_2 Internal Cost	$ 40,397	206,448	-	-	-	-	-	8	-	-	1	197,599
High Externalities, No CO_2 Internal Cost	$ 44,229	192,910	-	-	1	-	-	10	-	-	-	229,370
High Externalities, Use CO_2 Internal Cost	$ 39,225	167,668	-	-	2	-	-	9	-	-	-	275,759
Low Externalities, No CO_2 Internal Cost	$ 36,469	211,803	-	-	-	-	-	8	-	-	1	186,774
Low Externalities, Use CO_2 Internal Cost	$ 35,202	205,344	-	-	-	-	-	8	-	-	1	184,205
No Externalities, Use CO_2 Internal Cost	$ 34,035	212,327	-	-	-	-	-	6	-	-	2	186,279
No Externalities, No CO_2 Internal Cost	$ 34,035	212,327	-	-	-	-	-	6	-	-	2	186,279
Low Solar Price	$ 36,866	188,861	-	-	-	-	-	8	-	-	1	194,379
High Solar Price	$ 37,789	183,625	-	-	2	-	-	2	-	-	3	239,365
Low Wind Price	$ 36,979	163,679	-	-	3	-	-	6	-	-	1	295,251
High Wind Price	$ 37,400	195,501	-	-	-	-	-	8	-	-	1	180,621
Low Forecast	$ 36,421	174,888	-	-	-	-	-	9	-	-	-	228,535
High Forecast	$ 40,145	201,042	-	-	-	-	5	7	-	-	4	170,495
Low Coal Cost	$ 37,342	185,283	-	-	-	-	-	8	-	-	1	212,531
High Coal Cost	$ 37,444	185,283	-	-	-	-	-	8	-	-	1	212,531
Low Gas Price	$ 37,054	194,649	-	-	-	-	-	2	-	-	4	(32,398)
High Gas Price	$ 37,290	162,488	-	-	3	-	-	8	-	-	-	311,261
Low Nuke Cost	$ 36,785	185,283	-	-	-	-	-	8	-	-	1	212,531
High Nuke Cost	$ 38,000	185,283	-	-	-	-	-	8	-	-	1	212,531
High Market Price	$ 37,204	186,452	-	-	1	-	-	7	-	-	1	325,360
Low Market Price	$ 37,256	179,976	-	-	-	-	-	8	-	-	1	83,743
Low Market Capacity	$ 37,468	192,320	-	-	-	-	-	6	-	-	2	109,873
No Market	$ 37,826	190,086	-	-	-	-	-	4	-	-	3	-

Select Strategist Outputs--Standard Assumptions

Scenario 110 KINE_SHEN_MONN_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,185	219,229	-	-	-	-	3	10	-	-	1	103,804
Mid Externalities, No CO_2 Internal Cost	$ 39,944	231,318	-	-	-	-	3	10	-	-	1	124,241
High Externalities, No CO_2 Internal Cost	$ 43,879	214,652	-	-	1	-	3	11	-	-	-	163,641
High Externalities, Use CO_2 Internal Cost	$ 39,218	186,673	-	-	2	-	3	10	-	-	-	200,203
Low Externalities, No CO_2 Internal Cost	$ 35,929	236,730	-	-	-	-	3	10	-	-	1	112,645
Low Externalities, Use CO_2 Internal Cost	$ 34,732	231,556	-	-	-	-	3	8	-	-	2	107,589
No Externalities, Use CO_2 Internal Cost	$ 33,437	238,852	-	-	-	-	3	8	-	-	2	110,505
No Externalities, No CO_2 Internal Cost	$ 33,437	238,852	-	-	-	-	3	8	-	-	2	110,505
Low Solar Price	$ 36,444	197,512	-	-	1	-	3	11	-	-	-	155,100
High Solar Price	$ 37,782	198,615	-	-	2	-	3	2	-	-	4	194,618
Low Wind Price	$ 36,645	178,010	-	2	2	-	2	5	-	-	2	247,007
High Wind Price	$ 37,185	219,229	-	-	-	-	3	10	-	-	1	103,804
Low Forecast	$ 36,142	194,107	-	-	-	-	2	11	-	-	-	163,673
High Forecast	$ 40,192	217,558	-	-	-	-	8	8	-	1	3	119,947
Low Coal Cost	$ 37,134	219,229	-	-	-	-	3	10	-	-	1	103,804
High Coal Cost	$ 37,236	219,229	-	-	-	-	3	10	-	-	1	103,804
Low Gas Price	$ 36,254	236,295	-	-	-	-	-	4	-	2	3	(142,052)
High Gas Price	$ 37,379	181,524	-	-	4	-	3	7	-	-	1	252,056
Low Nuke Cost	$ 36,886	219,229	-	-	-	-	3	10	-	-	1	103,804
High Nuke Cost	$ 37,484	219,229	-	-	-	-	3	10	-	-	1	103,804
High Market Price	$ 37,151	203,466	-	-	2	-	3	10	-	-	-	268,258
Low Market Price	$ 36,856	206,715	-	-	-	-	3	10	-	-	1	2,260
Low Market Capacity	$ 37,208	214,799	-	-	-	-	3	6	-	-	3	64,988
No Market	$ 37,427	209,646	-	-	-	-	3	4	-	-	4	-

Department Attachment 1

Select Strategist Outputs--Standard Assumptions

Scenario 111 KINE_SHEN_MONN_P RAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,013	177,204	-	-	-	-	-	8	-	-	-	221,880
Mid Externalities, No CO_2 Internal Cost	$ 40,000	195,634	-	-	-	-	-	8	-	-	-	219,413
High Externalities, No CO_2 Internal Cost	$ 43,836	195,634	-	-	-	-	-	8	-	-	-	219,413
High Externalities, Use CO_2 Internal Cost	$ 38,812	165,695	-	-	1	-	-	7	-	-	-	273,848
Low Externalities, No CO_2 Internal Cost	$ 36,164	195,634	-	-	-	-	-	8	-	-	-	219,413
Low Externalities, Use CO_2 Internal Cost	$ 34,895	193,371	-	-	-	-	-	8	-	-	-	212,927
No Externalities, Use CO_2 Internal Cost	$ 33,754	202,006	-	-	-	-	-	6	-	-	1	214,429
No Externalities, No CO_2 Internal Cost	$ 33,754	202,006	-	-	-	-	-	6	-	-	1	214,429
Low Solar Price	$ 36,472	176,770	-	-	-	-	-	8	-	-	-	222,739
High Solar Price	$ 37,433	175,610	-	-	2	-	-	2	-	-	2	268,910
Low Wind Price	$ 36,662	163,322	-	-	3	-	-	6	-	-	-	297,456
High Wind Price	$ 37,019	179,554	-	-	-	-	-	8	-	-	-	213,425
Low Forecast	$ 36,066	170,360	-	-	-	-	-	6	-	-	-	243,762
High Forecast	$ 39,778	194,621	-	-	-	-	5	8	-	-	2	181,296
Low Coal Cost	$ 36,962	177,204	-	-	-	-	-	8	-	-	-	221,880
High Coal Cost	$ 37,064	177,204	-	-	-	-	-	8	-	-	-	221,880
Low Gas Price	$ 36,807	186,904	-	-	-	-	-	2	-	-	3	(27,489)
High Gas Price	$ 36,854	159,040	-	-	3	-	-	6	-	-	-	321,509
Low Nuke Cost	$ 36,383	177,204	-	-	-	-	-	8	-	-	-	221,880
High Nuke Cost	$ 37,644	177,204	-	-	-	-	-	8	-	-	-	221,880
High Market Price	$ 36,790	182,012	-	-	1	-	-	7	-	-	-	330,425
Low Market Price	$ 36,935	167,517	-	-	-	-	-	8	-	-	-	113,156
Low Market Capacity	$ 37,099	183,506	-	-	-	-	-	6	-	-	1	126,438
No Market	$ 37,371	187,420	-	-	-	-	-	4	-	-	2	-

Select Strategist Outputs--Standard Assumptions

Scenario 112 KINE_SHEE_MONN_P RAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,137	194,638	-	-	-	-	-	12	-	-	3	148,399
Mid Externalities, No CO_2 Internal Cost	$ 39,655	200,483	-	-	-	-	-	14	-	-	2	163,311
High Externalities, No CO_2 Internal Cost	$ 43,148	197,454	-	-	-	-	-	16	-	-	1	168,716
High Externalities, Use CO_2 Internal Cost	$ 38,928	164,106	-	-	2	-	-	12	-	-	2	256,121
Low Externalities, No CO_2 Internal Cost	$ 36,079	207,408	-	-	-	-	-	12	-	-	3	150,305
Low Externalities, Use CO_2 Internal Cost	$ 35,046	202,025	-	-	-	-	-	12	-	-	3	148,521
No Externalities, Use CO_2 Internal Cost	$ 33,888	208,673	-	-	-	-	-	12	-	-	3	148,492
No Externalities, No CO_2 Internal Cost	$ 33,888	208,673	-	-	-	-	-	12	-	-	3	148,492
Low Solar Price	$ 36,421	185,657	-	-	-	-	-	16	-	-	1	166,247
High Solar Price	$ 37,658	192,831	-	-	1	-	-	6	-	-	5	164,770
Low Wind Price	$ 36,647	161,136	-	-	4	-	-	8	-	-	3	274,762
High Wind Price	$ 37,137	194,638	-	-	-	-	-	12	-	-	3	148,399
Low Forecast	$ 36,151	171,043	-	-	-	-	-	14	-	-	1	209,580
High Forecast	$ 39,957	198,191	-	-	-	-	5	10	-	-	6	151,227
Low Coal Cost	$ 37,094	194,638	-	-	-	-	-	12	-	-	3	148,399
High Coal Cost	$ 37,179	194,638	-	-	-	-	-	12	-	-	3	148,399
Low Gas Price	$ 36,575	205,743	-	-	-	-	-	3	-	-	7	(81,510)
High Gas Price	$ 37,112	161,212	-	-	3	-	-	11	-	-	2	282,845
Low Nuke Cost	$ 36,644	194,638	-	-	-	-	-	12	-	-	3	148,399
High Nuke Cost	$ 37,629	194,638	-	-	-	-	-	12	-	-	3	148,399
High Market Price	$ 36,992	183,890	-	-	1	-	-	13	-	-	2	295,061
Low Market Price	$ 36,941	181,997	-	-	-	-	-	12	-	-	3	52,724
Low Market Capacity	$ 37,239	191,233	-	-	-	-	-	9	-	-	4	93,501
No Market	$ 37,578	186,984	-	-	-	-	-	7	-	-	5	-

Department Attachment 1

Select Strategist Outputs--Standard Assumptions

Scenario 113 KINN_SHEE_MONE_P RAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,123	188,736	-	-	-	-	-	13	-	-	1	175,392
Mid Externalities, No CO_2 Internal Cost	$ 40,106	223,133	-	-	-	-	-	13	-	-	1	155,740
High Externalities, No CO_2 Internal Cost	$ 43,981	207,346	-	-	1	-	-	14	-	-	-	188,600
High Externalities, Use CO_2 Internal Cost	$ 39,009	171,984	-	-	2	-	-	11	-	-	1	236,071
Low Externalities, No CO_2 Internal Cost	$ 36,144	229,286	-	-	-	-	-	10	-	-	2	144,917
Low Externalities, Use CO_2 Internal Cost	$ 34,915	217,357	-	-	-	-	-	10	-	-	2	137,406
No Externalities, Use CO_2 Internal Cost	$ 33,692	230,433	-	-	-	-	-	10	-	-	2	144,369
No Externalities, No CO_2 Internal Cost	$ 33,692	230,433	-	-	-	-	-	10	-	-	2	144,369
Low Solar Price	$ 36,476	197,066	-	-	-	-	-	13	-	-	1	145,620
High Solar Price	$ 37,602	191,262	-	-	1	-	-	5	-	-	4	191,001
Low Wind Price	$ 36,632	167,107	-	-	5	-	-	6	-	-	2	262,457
High Wind Price	$ 37,130	204,632	-	-	-	-	-	10	-	-	2	129,952
Low Forecast	$ 36,137	183,814	-	-	-	-	-	11	-	-	1	183,646
High Forecast	$ 40,015	208,928	-	-	-	-	4	10	-	1	4	130,633
Low Coal Cost	$ 37,057	188,736	-	-	-	-	-	13	-	-	1	175,392
High Coal Cost	$ 37,188	188,736	-	-	-	-	-	13	-	-	1	175,392
Low Gas Price	$ 36,410	209,260	-	-	-	-	-	2	-	-	6	(95,484)
High Gas Price	$ 37,193	163,282	-	-	4	-	-	11	-	-	-	284,829
Low Nuke Cost	$ 36,685	188,736	-	-	-	-	-	13	-	-	1	175,392
High Nuke Cost	$ 37,560	188,736	-	-	-	-	-	13	-	-	1	175,392
High Market Price	$ 37,023	191,562	-	-	1	-	-	12	-	-	1	296,225
Low Market Price	$ 36,878	189,807	-	-	-	-	-	10	-	-	2	29,182
Low Market Capacity	$ 37,156	202,443	-	-	-	-	-	8	-	-	3	78,964
No Market	$ 37,412	198,676	-	-	-	-	-	6	-	-	4	-

Select Strategist Outputs--Standard Assumptions

Scenario 114 KINN_SHEE_MONX_P RAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,391	180,557	-	-	-	-	-	8	-	-	1	206,077
Mid Externalities, No CO_2 Internal Cost	$ 40,512	210,940	-	-	-	-	-	8	-	-	1	195,274
High Externalities, No CO_2 Internal Cost	$ 44,299	194,609	-	-	1	-	-	10	-	-	-	230,758
High Externalities, Use CO_2 Internal Cost	$ 39,152	162,803	-	-	2	-	-	9	-	-	-	268,648
Low Externalities, No CO_2 Internal Cost	$ 36,577	214,712	-	-	-	-	-	8	-	-	1	186,912
Low Externalities, Use CO_2 Internal Cost	$ 35,318	202,282	-	-	-	-	-	8	-	-	1	180,604
No Externalities, Use CO_2 Internal Cost	$ 34,164	214,712	-	-	-	-	-	8	-	-	1	186,912
No Externalities, No CO_2 Internal Cost	$ 34,164	214,712	-	-	-	-	-	8	-	-	1	186,912
Low Solar Price	$ 36,872	173,240	-	-	1	-	-	10	-	-	-	217,321
High Solar Price	$ 37,785	180,526	-	-	1	-	-	3	-	-	3	226,289
Low Wind Price	$ 36,959	157,308	-	-	4	-	-	5	-	-	1	293,707
High Wind Price	$ 37,398	190,776	-	-	-	-	-	8	-	-	1	174,167
Low Forecast	$ 36,429	168,475	-	-	1	-	-	8	-	-	-	236,718
High Forecast	$ 40,107	194,945	-	-	-	-	2	10	-	-	4	167,722
Low Coal Cost	$ 37,325	180,557	-	-	-	-	-	8	-	-	1	206,077
High Coal Cost	$ 37,457	180,557	-	-	-	-	-	8	-	-	1	206,077
Low Gas Price	$ 37,008	189,140	-	-	-	-	-	2	-	-	4	(44,468)
High Gas Price	$ 37,270	157,700	-	-	3	-	-	8	-	-	-	306,783
Low Nuke Cost	$ 36,783	180,557	-	-	-	-	-	8	-	-	1	206,077
High Nuke Cost	$ 37,998	180,557	-	-	-	-	-	8	-	-	1	206,077
High Market Price	$ 37,199	181,308	-	-	1	-	-	10	-	-	-	323,679
Low Market Price	$ 37,242	174,182	-	-	-	-	-	8	-	-	1	75,128
Low Market Capacity	$ 37,447	187,780	-	-	-	-	-	6	-	-	2	106,271
No Market	$ 37,777	184,054	-	-	-	-	-	4	-	-	3	-

Select Strategist Outputs--Standard Assumptions

Scenario 115 KINN_SHEE_MONN_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,158	200,205	-	-	-	-	1	12	-	-	1	139,254
Mid Externalities, No CO_2 Internal Cost	$ 40,036	235,461	-	-	-	-	1	12	-	-	1	122,748
High Externalities, No CO_2 Internal Cost	$ 44,007	233,520	-	-	-	-	1	12	-	-	1	126,650
High Externalities, Use CO_2 Internal Cost	$ 39,162	182,601	-	-	2	-	1	10	-	-	1	200,373
Low Externalities, No CO_2 Internal Cost	$ 36,025	242,442	-	-	-	-	1	10	-	-	2	111,141
Low Externalities, Use CO_2 Internal Cost	$ 34,826	229,980	-	-	-	-	1	10	-	-	2	102,921
No Externalities, Use CO_2 Internal Cost	$ 33,537	246,331	-	-	-	-	1	8	-	-	3	105,674
No Externalities, No CO_2 Internal Cost	$ 33,537	246,331	-	-	-	-	1	8	-	-	3	105,674
Low Solar Price	$ 36,419	208,535	-	-	-	-	1	12	-	-	1	109,483
High Solar Price	$ 37,730	200,949	-	-	2	-	1	4	-	-	4	161,943
Low Wind Price	$ 36,620	173,119	-	1	4	-	-	7	-	-	2	244,104
High Wind Price	$ 37,168	210,449	-	-	-	-	1	12	-	-	1	105,579
Low Forecast	$ 36,137	195,462	-	-	-	-	-	11	-	-	1	145,545
High Forecast	$ 40,161	220,431	-	-	-	-	6	10	-	1	3	97,128
Low Coal Cost	$ 37,093	200,205	-	-	-	-	1	12	-	-	1	139,254
High Coal Cost	$ 37,224	200,205	-	-	-	-	1	12	-	-	1	139,254
Low Gas Price	$ 36,206	229,068	-	-	-	-	-	2	-	1	5	(146,048)
High Gas Price	$ 37,387	175,253	-	-	4	-	1	9	-	-	1	252,908
Low Nuke Cost	$ 36,859	200,205	-	-	-	-	1	12	-	-	1	139,254
High Nuke Cost	$ 37,458	200,205	-	-	-	-	1	12	-	-	1	139,254
High Market Price	$ 37,147	203,259	-	-	1	-	1	11	-	-	1	264,523
Low Market Price	$ 36,827	203,466	-	-	-	-	1	10	-	-	2	(10,440)
Low Market Capacity	$ 37,184	214,975	-	-	-	-	1	8	-	-	3	52,745
No Market	$ 37,408	209,646	-	-	1	-	1	5	-	-	4	-

Select Strategist Outputs--Standard Assumptions

Scenario 116 KINN_SHEE_MONN_PRAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,003	173,556	-	-	-	-	-	8	-	-	-	214,698
Mid Externalities, No CO_2 Internal Cost	$ 40,110	199,573	-	-	-	-	-	8	-	-	-	217,181
High Externalities, No CO_2 Internal Cost	$ 43,963	199,573	-	-	-	-	-	8	-	-	-	217,181
High Externalities, Use CO_2 Internal Cost	$ 38,757	162,547	-	-	-	-	-	8	-	-	-	261,420
Low Externalities, No CO_2 Internal Cost	$ 36,256	199,573	-	-	-	-	-	8	-	-	-	217,181
Low Externalities, Use CO_2 Internal Cost	$ 35,003	189,957	-	-	-	-	-	8	-	-	-	207,410
No Externalities, Use CO_2 Internal Cost	$ 33,872	206,243	-	-	-	-	-	6	-	-	1	212,668
No Externalities, No CO_2 Internal Cost	$ 33,872	206,243	-	-	-	-	-	6	-	-	1	212,668
Low Solar Price	$ 36,493	173,122	-	-	-	-	-	8	-	-	-	215,557
High Solar Price	$ 37,418	170,798	-	-	1	-	-	3	-	-	2	261,513
Low Wind Price	$ 36,643	153,334	-	-	4	-	-	5	-	-	-	305,200
High Wind Price	$ 37,008	175,905	-	-	-	-	-	8	-	-	-	206,243
Low Forecast	$ 36,061	167,259	-	-	-	-	-	7	-	-	-	235,404
High Forecast	$ 39,756	192,875	-	-	-	-	2	9	-	-	3	170,816
Low Coal Cost	$ 36,937	173,556	-	-	-	-	-	8	-	-	-	214,698
High Coal Cost	$ 37,069	173,556	-	-	-	-	-	8	-	-	-	214,698
Low Gas Price	$ 36,769	174,839	-	-	-	-	-	2	-	-	3	(18,771)
High Gas Price	$ 36,839	154,737	-	-	3	-	-	6	-	-	-	315,465
Low Nuke Cost	$ 36,372	173,556	-	-	-	-	-	8	-	-	-	214,698
High Nuke Cost	$ 37,633	173,556	-	-	-	-	-	8	-	-	-	214,698
High Market Price	$ 36,790	180,365	-	-	-	-	-	8	-	-	-	322,118
Low Market Price	$ 36,913	159,667	-	-	-	-	-	8	-	-	-	111,465
Low Market Capacity	$ 37,072	178,970	-	-	-	-	-	6	-	-	1	122,224
No Market	$ 37,344	185,476	-	-	-	-	-	2	-	-	3	-

Select Strategist Outputs--Standard Assumptions

Scenario 117 KINN_SHEN_MONE_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,235	218,204	-	-	-	-	2	8	-	1	-	125,593
Mid Externalities, No CO_2 Internal Cost	$ 40,482	257,930	-	-	-	-	2	8	-	1	-	115,234
High Externalities, No CO_2 Internal Cost	$ 44,834	232,730	-	1	-	-	3	8	-	-	-	169,099
High Externalities, Use CO_2 Internal Cost	$ 39,339	186,538	-	1	2	-	3	6	-	-	-	216,633
Low Externalities, No CO_2 Internal Cost	$ 36,038	261,771	-	-	-	-	2	8	-	1	-	106,441
Low Externalities, Use CO_2 Internal Cost	$ 34,644	248,990	-	-	-	-	2	8	-	1	-	96,944
No Externalities, Use CO_2 Internal Cost	$ 33,286	261,771	-	-	-	-	2	8	-	1	-	106,441
No Externalities, No CO_2 Internal Cost	$ 33,286	261,771	-	-	-	-	2	8	-	1	-	106,441
Low Solar Price	$ 36,579	204,767	-	1	-	-	3	8	-	-	-	150,775
High Solar Price	$ 37,780	212,736	-	-	2	-	2	4	-	1	1	162,029
Low Wind Price	$ 36,639	180,637	-	1	4	-	3	5	-	-	-	244,992
High Wind Price	$ 37,240	232,204	-	-	-	-	2	8	-	1	-	82,994
Low Forecast	$ 36,129	208,113	-	-	-	-	2	8	-	-	-	138,321
High Forecast	$ 40,227	237,381	-	-	-	-	6	9	-	3	-	85,529
Low Coal Cost	$ 37,161	218,204	-	-	-	-	2	8	-	1	-	125,593
High Coal Cost	$ 37,309	218,204	-	-	-	-	2	8	-	1	-	125,593
Low Gas Price	$ 36,129	240,122	-	-	-	-	2	1	-	1	3	(148,590)
High Gas Price	$ 37,495	180,498	-	1	3	-	3	6	-	-	-	266,181
Low Nuke Cost	$ 36,996	218,204	-	-	-	-	2	8	-	1	-	125,593
High Nuke Cost	$ 37,474	218,204	-	-	-	-	2	8	-	1	-	125,593
High Market Price	$ 37,252	209,234	-	1	-	-	3	8	-	-	-	276,077
Low Market Price	$ 36,842	218,164	-	-	-	-	2	8	-	1	-	(23,774)
Low Market Capacity	$ 37,205	228,050	-	-	-	-	2	8	-	1	-	48,538
No Market	$ 37,377	227,648	-	-	-	-	2	3	-	1	2	-

Select Strategist Outputs--Standard Assumptions

Scenario 118 KINN_SHEN_MONX_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,492	204,621	-	-	-	-	1	7	-	-	-	159,887
Mid Externalities, No CO_2 Internal Cost	$ 40,852	240,833	-	-	-	-	1	7	-	-	-	155,800
High Externalities, No CO_2 Internal Cost	$ 45,181	222,817	-	-	-	-	1	7	-	-	-	206,431
High Externalities, Use CO_2 Internal Cost	$ 39,522	185,196	-	-	1	-	1	6	-	-	-	222,226
Low Externalities, No CO_2 Internal Cost	$ 36,472	244,605	-	-	-	-	1	7	-	-	-	147,438
Low Externalities, Use CO_2 Internal Cost	$ 35,048	231,245	-	-	-	-	1	7	-	-	-	138,697
No Externalities, Use CO_2 Internal Cost	$ 33,756	244,605	-	-	-	-	1	7	-	-	-	147,438
No Externalities, No CO_2 Internal Cost	$ 33,756	244,605	-	-	-	-	1	7	-	-	-	147,438
Low Solar Price	$ 36,931	209,769	-	-	-	-	1	7	-	-	-	139,324
High Solar Price	$ 37,950	201,882	-	-	1	-	1	6	-	-	-	183,942
Low Wind Price	$ 36,997	176,242	-	1	3	-	-	4	-	-	-	260,623
High Wind Price	$ 37,499	214,840	-	-	-	-	1	7	-	-	-	127,978
Low Forecast	$ 36,485	195,009	-	-	-	-	-	6	-	-	-	182,259
High Forecast	$ 40,429	217,008	-	-	-	-	6	7	-	1	1	131,730
Low Coal Cost	$ 37,418	204,621	-	-	-	-	1	7	-	-	-	159,887
High Coal Cost	$ 37,566	204,621	-	-	-	-	1	7	-	-	-	159,887
Low Gas Price	$ 36,722	214,113	-	-	-	-	1	2	-	-	2	(94,143)
High Gas Price	$ 37,641	184,120	-	-	2	-	1	5	-	-	-	263,748
Low Nuke Cost	$ 37,073	204,621	-	-	-	-	1	7	-	-	-	159,887
High Nuke Cost	$ 37,911	204,621	-	-	-	-	1	7	-	-	-	159,887
High Market Price	$ 37,425	208,464	-	-	-	-	1	7	-	-	-	281,223
Low Market Price	$ 37,208	199,285	-	-	-	-	1	7	-	-	-	22,274
Low Market Capacity	$ 37,452	211,299	-	-	-	-	1	7	-	-	-	77,677
No Market	$ 37,622	210,326	-	-	-	-	1	2	-	-	2	-

Select Strategist Outputs--Standard Assumptions

Scenario 119 KINN_SHEN_MONE_P RAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,051	188,939	-	-	-	-	-	5	-	-	-	202,246
Mid Externalities, No CO_2 Internal Cost	$ 40,528	220,028	-	-	-	-	-	5	-	-	-	209,664
High Externalities, No CO_2 Internal Cost	$ 44,804	220,028	-	-	-	-	-	5	-	-	-	209,664
High Externalities, Use CO_2 Internal Cost	$ 38,954	173,783	-	-	2	-	-	3	-	-	-	257,167
Low Externalities, No CO_2 Internal Cost	$ 36,252	220,028	-	-	-	-	-	5	-	-	-	209,664
Low Externalities, Use CO_2 Internal Cost	$ 34,790	209,689	-	-	-	-	-	5	-	-	-	198,624
No Externalities, Use CO_2 Internal Cost	$ 33,581	224,856	-	-	-	-	-	5	-	-	-	205,733
No Externalities, No CO_2 Internal Cost	$ 33,581	224,856	-	-	-	-	-	5	-	-	-	205,733
Low Solar Price	$ 36,600	188,505	-	-	-	-	-	5	-	-	-	203,105
High Solar Price	$ 37,411	182,097	-	-	2	-	-	3	-	-	-	256,002
Low Wind Price	$ 36,683	170,280	-	-	2	-	-	3	-	-	-	285,647
High Wind Price	$ 37,057	191,289	-	-	-	-	-	5	-	-	-	193,791
Low Forecast	$ 36,110	182,247	-	-	-	-	-	3	-	-	-	222,791
High Forecast	$ 39,878	204,689	-	-	-	-	4	8	-	1	-	167,634
Low Coal Cost	$ 36,977	188,939	-	-	-	-	-	5	-	-	-	202,246
High Coal Cost	$ 37,126	188,939	-	-	-	-	-	5	-	-	-	202,246
Low Gas Price	$ 36,655	195,196	-	-	-	-	-	1	-	-	2	(55,280)
High Gas Price	$ 37,021	172,493	-	-	2	-	-	3	-	-	-	299,977
Low Nuke Cost	$ 36,476	188,939	-	-	-	-	-	5	-	-	-	202,246
High Nuke Cost	$ 37,627	188,939	-	-	-	-	-	5	-	-	-	202,246
High Market Price	$ 36,879	195,678	-	-	1	-	-	4	-	-	-	317,173
Low Market Price	$ 36,907	174,193	-	-	-	-	-	5	-	-	-	93,579
Low Market Capacity	$ 37,034	192,258	-	-	-	-	-	5	-	-	-	117,165
No Market	$ 37,226	195,175	-	-	-	-	-	3	-	-	1	-

Select Strategist Outputs--Standard Assumptions

Scenario 120 KINN_SHEN_MONX_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,400	179,169	-	-	-	-	-	1	-	-	-	241,291
Mid Externalities, No CO_2 Internal Cost	$ 40,985	209,360	-	-	-	-	-	1	-	-	-	246,821
High Externalities, No CO_2 Internal Cost	$ 45,214	206,731	-	-	-	-	-	1	-	-	-	254,444
High Externalities, Use CO_2 Internal Cost	$ 39,202	166,654	-	-	1	-	-	-	-	-	-	286,989
Low Externalities, No CO_2 Internal Cost	$ 36,754	209,360	-	-	-	-	-	1	-	-	-	246,821
Low Externalities, Use CO_2 Internal Cost	$ 35,263	198,347	-	-	-	-	-	1	-	-	-	237,110
No Externalities, Use CO_2 Internal Cost	$ 34,117	211,541	-	-	-	-	-	1	-	-	-	243,604
No Externalities, No CO_2 Internal Cost	$ 34,117	211,541	-	-	-	-	-	1	-	-	-	243,604
Low Solar Price	$ 37,076	178,898	-	-	-	-	-	1	-	-	-	240,525
High Solar Price	$ 37,653	174,243	-	-	1	-	-	-	-	-	-	280,547
Low Wind Price	$ 37,109	167,105	-	-	1	-	-	-	-	-	-	300,868
High Wind Price	$ 37,406	181,519	-	-	-	-	-	1	-	-	-	232,836
Low Forecast	$ 36,490	171,423	-	-	-	-	-	-	-	-	-	268,365
High Forecast	$ 39,998	191,799	-	-	-	-	2	8	-	-	-	208,355
Low Coal Cost	$ 37,326	179,169	-	-	-	-	-	1	-	-	-	241,291
High Coal Cost	$ 37,474	179,169	-	-	-	-	-	1	-	-	-	241,291
Low Gas Price	$ 37,317	172,213	-	-	-	-	-	1	-	-	-	15,648
High Gas Price	$ 37,237	168,351	-	-	1	-	-	-	-	-	-	319,429
Low Nuke Cost	$ 36,661	179,169	-	-	-	-	-	1	-	-	-	241,291
High Nuke Cost	$ 38,139	179,169	-	-	-	-	-	1	-	-	-	241,291
High Market Price	$ 37,151	187,509	-	-	1	-	-	-	-	-	-	340,833
Low Market Price	$ 37,341	162,241	-	-	-	-	-	1	-	-	-	135,961
Low Market Capacity	$ 37,419	179,534	-	-	-	-	-	1	-	-	-	145,721
No Market	$ 37,715	177,959	-	-	-	-	-	1	-	-	-	-

Select Strategist Outputs--Standard Assumptions

Scenario 121 KINN_SHEE_MONE_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,095	205,713	-	-	-	-	2	11	-	1	-	124,270
Mid Externalities, No CO_2 Internal Cost	$ 39,917	240,985	-	-	-	-	2	11	-	1	-	108,700
High Externalities, No CO_2 Internal Cost	$ 43,906	215,722	-	1	-	-	3	11	-	-	-	161,424
High Externalities, Use CO_2 Internal Cost	$ 39,148	181,408	-	1	1	-	3	8	-	-	1	203,443
Low Externalities, No CO_2 Internal Cost	$ 35,886	247,966	-	-	-	-	2	9	-	1	1	97,093
Low Externalities, Use CO_2 Internal Cost	$ 34,703	235,607	-	-	-	-	2	9	-	1	1	88,424
No Externalities, Use CO_2 Internal Cost	$ 33,386	251,855	-	-	-	-	2	7	-	1	2	91,626
No Externalities, No CO_2 Internal Cost	$ 33,386	251,855	-	-	-	-	2	7	-	1	2	91,626
Low Solar Price	$ 36,331	214,043	-	-	-	-	2	11	-	1	-	94,499
High Solar Price	$ 37,690	206,458	-	-	2	-	2	3	-	1	3	146,959
Low Wind Price	$ 36,552	175,001	-	1	4	-	3	4	-	-	2	238,304
High Wind Price	$ 37,104	215,957	-	-	-	-	2	11	-	1	-	90,596
Low Forecast	$ 36,008	196,118	-	-	-	-	2	11	-	-	-	135,806
High Forecast	$ 40,123	227,951	-	-	-	-	6	10	-	3	1	79,536
Low Coal Cost	$ 37,029	205,713	-	-	-	-	2	11	-	1	-	124,270
High Coal Cost	$ 37,161	205,713	-	-	-	-	2	11	-	1	-	124,270
Low Gas Price	$ 36,027	234,804	-	-	-	-	2	-	-	1	5	(158,857)
High Gas Price	$ 37,354	171,192	-	1	3	-	3	9	-	-	-	258,580
Low Nuke Cost	$ 36,856	205,713	-	-	-	-	2	11	-	1	-	124,270
High Nuke Cost	$ 37,333	205,713	-	-	-	-	2	11	-	1	-	124,270
High Market Price	$ 37,124	208,979	-	-	1	-	2	10	-	1	-	251,758
Low Market Price	$ 36,723	209,372	-	-	-	-	2	9	-	1	1	(26,391)
Low Market Capacity	$ 37,113	220,515	-	-	-	-	2	7	-	1	2	42,489
No Market	$ 37,320	215,273	-	-	1	-	2	4	-	1	3	-

Select Strategist Outputs--Standard Assumptions

Scenario 122 KINN_SHEE_MONE_P RAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 36,894	178,298	-	-	-	-	-	8	-	-	-	198,077
Mid Externalities, No CO_2 Internal Cost	$ 39,969	205,101	-	-	-	-	-	8	-	-	-	201,668
High Externalities, No CO_2 Internal Cost	$ 43,869	205,101	-	-	-	-	-	8	-	-	-	201,668
High Externalities, Use CO_2 Internal Cost	$ 38,713	167,182	-	-	-	-	-	8	-	-	-	244,901
Low Externalities, No CO_2 Internal Cost	$ 36,068	205,101	-	-	-	-	-	8	-	-	-	201,668
Low Externalities, Use CO_2 Internal Cost	$ 34,823	195,238	-	-	-	-	-	8	-	-	-	191,351
No Externalities, Use CO_2 Internal Cost	$ 33,657	211,771	-	-	-	-	-	6	-	-	1	197,154
No Externalities, No CO_2 Internal Cost	$ 33,657	211,771	-	-	-	-	-	6	-	-	1	197,154
Low Solar Price	$ 36,385	177,864	-	-	-	-	-	8	-	-	-	198,936
High Solar Price	$ 37,309	175,540	-	-	1	-	-	3	-	-	2	244,892
Low Wind Price	$ 36,534	158,076	-	-	4	-	-	5	-	-	-	288,579
High Wind Price	$ 36,899	180,648	-	-	-	-	-	8	-	-	-	189,622
Low Forecast	$ 35,946	171,851	-	-	-	-	-	7	-	-	-	219,336
High Forecast	$ 39,765	196,014	-	-	-	-	4	7	-	1	2	160,088
Low Coal Cost	$ 36,828	178,298	-	-	-	-	-	8	-	-	-	198,077
High Coal Cost	$ 36,960	178,298	-	-	-	-	-	8	-	-	-	198,077
Low Gas Price	$ 36,529	180,536	-	-	-	-	-	2	-	-	3	(39,179)
High Gas Price	$ 36,809	159,603	-	-	3	-	-	6	-	-	-	299,195
Low Nuke Cost	$ 36,318	178,298	-	-	-	-	-	8	-	-	-	198,077
High Nuke Cost	$ 37,469	178,298	-	-	-	-	-	8	-	-	-	198,077
High Market Price	$ 36,722	185,499	-	-	-	-	-	8	-	-	-	308,106
Low Market Price	$ 36,760	164,668	-	-	-	-	-	8	-	-	-	92,146
Low Market Capacity	$ 36,913	183,408	-	-	-	-	-	6	-	-	1	112,708
No Market	$ 37,115	189,364	-	-	-	-	-	2	-	-	3	-

Select Strategist Outputs--Standard Assumptions

Scenario 123 KINN_SHEE_MONX_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,347	191,039	-	-	-	-	1	10	-	-	-	159,778
Mid Externalities, No CO_2 Internal Cost	$ 40,260	222,930	-	-	-	-	1	10	-	-	-	148,955
High Externalities, No CO_2 Internal Cost	$ 44,168	220,380	-	-	-	-	1	10	-	-	-	153,081
High Externalities, Use CO_2 Internal Cost	$ 39,287	174,532	-	-	2	-	1	8	-	-	-	226,178
Low Externalities, No CO_2 Internal Cost	$ 36,310	226,966	-	-	-	-	1	10	-	-	-	141,146
Low Externalities, Use CO_2 Internal Cost	$ 35,101	218,132	-	-	-	-	1	8	-	-	1	132,023
No Externalities, Use CO_2 Internal Cost	$ 33,852	231,542	-	-	-	-	1	8	-	-	1	139,744
No Externalities, No CO_2 Internal Cost	$ 33,852	231,542	-	-	-	-	1	8	-	-	1	139,744
Low Solar Price	$ 36,674	195,467	-	-	-	-	1	10	-	-	-	138,870
High Solar Price	$ 37,863	193,705	-	-	1	-	1	5	-	-	2	177,955
Low Wind Price	$ 36,874	168,340	-	1	2	-	-	6	-	-	1	257,199
High Wind Price	$ 37,356	198,544	-	-	-	-	1	10	-	-	-	134,515
Low Forecast	$ 36,330	186,076	-	-	-	-	-	9	-	-	-	169,007
High Forecast	$ 40,327	207,936	-	-	-	-	6	8	-	1	2	124,883
Low Coal Cost	$ 37,281	191,039	-	-	-	-	1	10	-	-	-	159,778
High Coal Cost	$ 37,412	191,039	-	-	-	-	1	10	-	-	-	159,778
Low Gas Price	$ 36,608	218,296	-	-	-	-	-	-	-	1	4	(131,471)
High Gas Price	$ 37,435	169,918	-	-	3	-	1	8	-	-	-	265,533
Low Nuke Cost	$ 36,928	191,039	-	-	-	-	1	10	-	-	-	159,778
High Nuke Cost	$ 37,766	191,039	-	-	-	-	1	10	-	-	-	159,778
High Market Price	$ 37,279	200,233	-	-	-	-	1	10	-	-	-	260,361
Low Market Price	$ 37,084	187,986	-	-	-	-	1	10	-	-	-	25,650
Low Market Capacity	$ 37,353	203,816	-	-	-	-	1	6	-	-	2	72,293
No Market	$ 37,547	200,834	-	-	-	-	1	4	-	-	3	-

Select Strategist Outputs--Standard Assumptions

Scenario 124 KINN_SHEE_MONX_P RAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,223	169,326	-	-	-	-	-	4	-	-	-	237,041
Mid Externalities, No CO_2 Internal Cost	$ 40,428	195,552	-	-	-	-	-	4	-	-	-	239,193
High Externalities, No CO_2 Internal Cost	$ 44,286	175,118	-	-	3	-	-	2	-	-	-	310,446
High Externalities, Use CO_2 Internal Cost	$ 38,935	158,058	-	-	1	-	-	3	-	-	-	284,569
Low Externalities, No CO_2 Internal Cost	$ 36,551	195,552	-	-	-	-	-	4	-	-	-	239,193
Low Externalities, Use CO_2 Internal Cost	$ 35,266	184,814	-	-	-	-	-	4	-	-	-	230,092
No Externalities, Use CO_2 Internal Cost	$ 34,164	197,732	-	-	-	-	-	4	-	-	-	235,976
No Externalities, No CO_2 Internal Cost	$ 34,164	197,732	-	-	-	-	-	4	-	-	-	235,976
Low Solar Price	$ 36,855	169,055	-	-	-	-	-	4	-	-	-	236,274
High Solar Price	$ 37,521	164,657	-	-	1	-	-	3	-	-	-	276,674
Low Wind Price	$ 36,897	154,028	-	-	3	-	-	2	-	-	-	305,539
High Wind Price	$ 37,229	171,675	-	-	-	-	-	4	-	-	-	228,586
Low Forecast	$ 36,304	162,894	-	-	-	-	-	2	-	-	-	261,429
High Forecast	$ 39,896	184,217	-	-	-	-	2	7	-	-	2	201,946
Low Coal Cost	$ 37,157	169,326	-	-	-	-	-	4	-	-	-	237,041
High Coal Cost	$ 37,289	169,326	-	-	-	-	-	4	-	-	-	237,041
Low Gas Price	$ 37,165	165,768	-	-	-	-	-	-	-	-	2	3,964
High Gas Price	$ 36,986	154,145	-	-	2	-	-	3	-	-	-	321,141
Low Nuke Cost	$ 36,484	169,326	-	-	-	-	-	4	-	-	-	237,041
High Nuke Cost	$ 37,962	169,326	-	-	-	-	-	4	-	-	-	237,041
High Market Price	$ 36,973	178,567	-	-	-	-	-	4	-	-	-	333,537
Low Market Price	$ 37,171	153,081	-	-	-	-	-	4	-	-	-	133,383
Low Market Capacity	$ 37,256	169,816	-	-	-	-	-	4	-	-	-	142,855
No Market	$ 37,565	168,185	-	-	-	-	-	2	-	-	1	-

Select Strategist Outputs--Standard Assumptions

Scenario 125 KINE_SHEN_MONE_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,127	224,416	-	-	-	-	5	8	-	1	-	89,892
Mid Externalities, No CO_2 Internal Cost	$ 39,833	236,499	-	-	-	-	5	8	-	1	-	110,892
High Externalities, No CO_2 Internal Cost	$ 43,817	236,499	-	-	-	-	5	8	-	1	-	110,892
High Externalities, Use CO_2 Internal Cost	$ 39,233	186,687	-	1	1	-	6	7	-	-	-	200,404
Low Externalities, No CO_2 Internal Cost	$ 35,799	241,910	-	-	-	-	5	8	-	1	-	99,297
Low Externalities, Use CO_2 Internal Cost	$ 34,617	236,791	-	-	-	-	5	6	-	1	1	93,944
No Externalities, Use CO_2 Internal Cost	$ 33,293	245,185	-	-	-	-	3	8	-	2	-	94,457
No Externalities, No CO_2 Internal Cost	$ 33,293	245,185	-	-	-	-	3	8	-	2	-	94,457
Low Solar Price	$ 36,369	219,100	-	-	-	-	5	8	-	1	-	101,593
High Solar Price	$ 37,748	205,504	-	-	2	-	3	2	-	2	2	176,187
Low Wind Price	$ 36,572	179,802	-	2	2	-	5	2	-	-	2	242,056
High Wind Price	$ 37,127	224,416	-	-	-	-	5	8	-	1	-	89,892
Low Forecast	$ 36,038	197,976	-	-	-	-	5	8	-	-	-	151,438
High Forecast	$ 40,155	225,499	-	-	-	-	8	8	-	3	1	102,258
Low Coal Cost	$ 37,075	224,416	-	-	-	-	5	8	-	1	-	89,892
High Coal Cost	$ 37,178	224,416	-	-	-	-	5	8	-	1	-	89,892
Low Gas Price	$ 36,086	241,562	-	-	-	-	3	1	-	2	3	(154,188)
High Gas Price	$ 37,402	181,445	-	1	3	-	6	4	-	-	1	251,957
Low Nuke Cost	$ 36,888	224,416	-	-	-	-	5	8	-	1	-	89,892
High Nuke Cost	$ 37,365	224,416	-	-	-	-	5	8	-	1	-	89,892
High Market Price	$ 37,139	214,490	-	-	1	-	5	7	-	1	-	248,054
Low Market Price	$ 36,760	212,285	-	-	-	-	5	8	-	1	-	(12,674)
Low Market Capacity	$ 37,142	220,015	-	-	-	-	5	4	-	1	2	55,582
No Market	$ 37,340	215,361	-	-	-	-	3	4	-	2	2	-

Select Strategist Outputs--Standard Assumptions

Scenario 126 KINE_SHEN_MONE_P RAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 36,914	181,759	-	-	-	-	1	7	-	-	-	206,308
Mid Externalities, No CO_2 Internal Cost	$ 39,867	200,780	-	-	-	-	1	7	-	-	-	204,636
High Externalities, No CO_2 Internal Cost	$ 43,745	200,780	-	-	-	-	1	7	-	-	-	204,636
High Externalities, Use CO_2 Internal Cost	$ 38,775	170,153	-	-	1	-	1	6	-	-	-	258,382
Low Externalities, No CO_2 Internal Cost	$ 35,989	200,780	-	-	-	-	1	7	-	-	-	204,636
Low Externalities, Use CO_2 Internal Cost	$ 34,727	198,375	-	-	-	-	1	7	-	-	-	197,891
No Externalities, Use CO_2 Internal Cost	$ 33,553	207,152	-	-	-	-	1	5	-	-	1	199,652
No Externalities, No CO_2 Internal Cost	$ 33,553	207,152	-	-	-	-	1	5	-	-	1	199,652
Low Solar Price	$ 36,367	181,325	-	-	-	-	1	7	-	-	-	207,167
High Solar Price	$ 37,339	180,164	-	-	2	-	1	1	-	-	2	253,338
Low Wind Price	$ 36,563	167,877	-	-	3	-	1	5	-	-	-	281,884
High Wind Price	$ 36,919	184,109	-	-	-	-	1	7	-	-	-	197,853
Low Forecast	$ 35,954	175,007	-	-	-	-	-	6	-	-	-	227,879
High Forecast	$ 39,800	200,851	-	-	-	-	6	5	-	1	2	168,299
Low Coal Cost	$ 36,863	181,759	-	-	-	-	1	7	-	-	-	206,308
High Coal Cost	$ 36,965	181,759	-	-	-	-	1	7	-	-	-	206,308
Low Gas Price	$ 36,583	192,293	-	-	-	-	1	1	-	-	3	(46,775)
High Gas Price	$ 36,828	163,703	-	-	3	-	1	5	-	-	-	306,255
Low Nuke Cost	$ 36,338	181,759	-	-	-	-	1	7	-	-	-	206,308
High Nuke Cost	$ 37,489	181,759	-	-	-	-	1	7	-	-	-	206,308
High Market Price	$ 36,728	186,906	-	-	1	-	1	6	-	-	-	317,324
Low Market Price	$ 36,794	172,286	-	-	-	-	1	7	-	-	-	94,961
Low Market Capacity	$ 36,949	187,752	-	-	-	-	1	5	-	-	1	117,684
No Market	$ 37,153	191,005	-	-	-	-	1	3	-	-	2	-

Select Strategist Outputs--Standard Assumptions

Scenario 127 KINE_SHEN_MONX_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,375	197,579	-	-	-	-	3	8	-	-	-	164,531
Mid Externalities, No CO_2 Internal Cost	$ 40,205	219,970	-	-	-	-	3	8	-	-	-	151,943
High Externalities, No CO_2 Internal Cost	$ 44,123	218,593	-	-	-	-	3	8	-	-	-	154,855
High Externalities, Use CO_2 Internal Cost	$ 39,369	179,520	-	-	2	-	3	6	-	-	-	233,133
Low Externalities, No CO_2 Internal Cost	$ 36,227	225,325	-	-	-	-	3	8	-	-	-	141,119
Low Externalities, Use CO_2 Internal Cost	$ 35,007	220,212	-	-	-	-	3	6	-	-	1	137,279
No Externalities, Use CO_2 Internal Cost	$ 33,750	227,529	-	-	-	-	3	6	-	-	1	140,606
No Externalities, No CO_2 Internal Cost	$ 33,750	227,529	-	-	-	-	3	6	-	-	1	140,606
Low Solar Price	$ 36,704	201,157	-	-	-	-	3	8	-	-	-	146,378
High Solar Price	$ 37,890	196,632	-	-	2	-	3	2	-	-	2	195,673
Low Wind Price	$ 36,907	170,970	-	2	2	-	2	3	-	-	1	267,094
High Wind Price	$ 37,382	207,798	-	-	-	-	3	8	-	-	-	132,621
Low Forecast	$ 36,353	191,172	-	-	-	-	2	7	-	-	-	177,331
High Forecast	$ 40,355	215,040	-	-	-	-	8	6	-	1	2	126,362
Low Coal Cost	$ 37,323	197,579	-	-	-	-	3	8	-	-	-	164,531
High Coal Cost	$ 37,426	197,579	-	-	-	-	3	8	-	-	-	164,531
Low Gas Price	$ 36,664	218,678	-	-	-	-	-	2	-	2	2	(107,792)
High Gas Price	$ 37,463	176,455	-	-	2	-	3	6	-	-	-	266,524
Low Nuke Cost	$ 36,956	197,579	-	-	-	-	3	8	-	-	-	164,531
High Nuke Cost	$ 37,794	197,579	-	-	-	-	3	8	-	-	-	164,531
High Market Price	$ 37,301	199,866	-	-	1	-	3	7	-	-	-	283,506
Low Market Price	$ 37,117	194,189	-	-	-	-	3	8	-	-	-	31,806
Low Market Capacity	$ 37,382	207,808	-	-	-	-	3	4	-	-	2	78,423
No Market	$ 37,575	205,151	-	-	-	-	3	2	-	-	3	-

Select Strategist Outputs--Standard Assumptions

Scenario 128 KINE_SHEN_MONX_PRAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,210	172,754	-	-	-	-	-	4	-	-	-	244,750
Mid Externalities, No CO_2 Internal Cost	$ 40,292	191,144	-	-	-	-	-	4	-	-	-	242,318
High Externalities, No CO_2 Internal Cost	$ 44,144	188,515	-	-	-	-	-	4	-	-	-	249,941
High Externalities, Use CO_2 Internal Cost	$ 38,975	161,900	-	-	1	-	-	3	-	-	-	293,344
Low Externalities, No CO_2 Internal Cost	$ 36,438	191,144	-	-	-	-	-	4	-	-	-	242,318
Low Externalities, Use CO_2 Internal Cost	$ 35,148	187,023	-	-	-	-	-	4	-	-	-	236,494
No Externalities, Use CO_2 Internal Cost	$ 34,040	195,651	-	-	-	-	-	4	-	-	-	238,207
No Externalities, No CO_2 Internal Cost	$ 34,040	195,651	-	-	-	-	-	4	-	-	-	238,207
Low Solar Price	$ 36,811	172,484	-	-	-	-	-	4	-	-	-	243,984
High Solar Price	$ 37,534	169,520	-	-	1	-	-	3	-	-	-	283,710
Low Wind Price	$ 36,899	159,442	-	-	2	-	-	2	-	-	-	309,029
High Wind Price	$ 37,216	175,104	-	-	-	-	-	4	-	-	-	236,295
Low Forecast	$ 36,276	166,111	-	-	-	-	-	2	-	-	-	270,162
High Forecast	$ 39,930	187,444	-	-	-	-	5	4	-	-	2	210,327
Low Coal Cost	$ 37,159	172,754	-	-	-	-	-	4	-	-	-	244,750
High Coal Cost	$ 37,262	172,754	-	-	-	-	-	4	-	-	-	244,750
Low Gas Price	$ 37,206	170,529	-	-	-	-	-	2	-	-	1	21,906
High Gas Price	$ 36,966	159,576	-	-	2	-	-	2	-	-	-	325,370
Low Nuke Cost	$ 36,471	172,754	-	-	-	-	-	4	-	-	-	244,750
High Nuke Cost	$ 37,950	172,754	-	-	-	-	-	4	-	-	-	244,750
High Market Price	$ 36,949	180,696	-	-	-	-	-	4	-	-	-	338,235
Low Market Price	$ 37,178	158,031	-	-	-	-	-	4	-	-	-	145,361
Low Market Capacity	$ 37,289	174,705	-	-	-	-	-	4	-	-	-	146,297
No Market	$ 37,602	174,505	-	-	-	-	-	2	-	-	1	-

Select Strategist Outputs--Standard Assumptions

Scenario 129 KINE_SHEE_MONN_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,099	212,180	-	-	-	-	3	9	-	-	3	94,335
Mid Externalities, No CO_2 Internal Cost	$ 39,469	219,070	-	-	-	-	3	11	-	-	2	112,415
High Externalities, No CO_2 Internal Cost	$ 43,090	219,070	-	-	-	-	3	11	-	-	2	112,415
High Externalities, Use CO_2 Internal Cost	$ 39,069	181,990	-	-	1	-	3	10	-	-	2	189,905
Low Externalities, No CO_2 Internal Cost	$ 35,790	225,647	-	-	-	-	3	9	-	-	3	98,979
Low Externalities, Use CO_2 Internal Cost	$ 34,802	219,397	-	-	-	-	3	9	-	-	3	96,455
No Externalities, Use CO_2 Internal Cost	$ 33,545	226,108	-	-	-	-	3	9	-	-	3	98,176
No Externalities, No CO_2 Internal Cost	$ 33,545	226,108	-	-	-	-	3	9	-	-	3	98,176
Low Solar Price	$ 36,345	205,716	-	-	-	-	3	11	-	-	2	107,847
High Solar Price	$ 37,700	193,390	-	-	3	-	3	2	-	-	5	175,977
Low Wind Price	$ 36,566	169,824	-	2	3	-	2	6	-	-	3	244,298
High Wind Price	$ 37,099	212,180	-	-	-	-	3	9	-	-	3	94,335
Low Forecast	$ 36,066	186,508	-	-	-	-	2	12	-	-	1	157,374
High Forecast	$ 40,115	213,767	-	-	-	-	8	7	-	1	5	105,307
Low Coal Cost	$ 37,056	212,180	-	-	-	-	3	9	-	-	3	94,335
High Coal Cost	$ 37,142	212,180	-	-	-	-	3	9	-	-	3	94,335
Low Gas Price	$ 36,150	242,293	-	-	-	-	-	1	-	2	6	(180,286)
High Gas Price	$ 37,281	173,856	-	-	4	-	3	8	-	-	2	243,780
Low Nuke Cost	$ 36,799	212,180	-	-	-	-	3	9	-	-	3	94,335
High Nuke Cost	$ 37,398	212,180	-	-	-	-	3	9	-	-	3	94,335
High Market Price	$ 37,074	197,722	-	-	1	-	3	10	-	-	2	257,802
Low Market Price	$ 36,761	200,484	-	-	-	-	3	9	-	-	3	(6,061)
Low Market Capacity	$ 37,132	207,220	-	-	-	-	3	7	-	-	4	58,575
No Market	$ 37,373	200,592	-	-	1	-	3	4	-	-	5	-

Select Strategist Outputs--Standard Assumptions

Scenario 130 KINE_SHEE_MONN_PRAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 36,916	166,650	-	-	-	-	-	12	-	-	-	217,702
Mid Externalities, No CO_2 Internal Cost	$ 39,495	180,516	-	-	-	-	-	12	-	-	-	211,816
High Externalities, No CO_2 Internal Cost	$ 42,954	180,516	-	-	-	-	-	12	-	-	-	211,816
High Externalities, Use CO_2 Internal Cost	$ 38,615	156,000	-	-	1	-	-	11	-	-	-	270,813
Low Externalities, No CO_2 Internal Cost	$ 36,031	185,912	-	-	-	-	-	10	-	-	1	207,706
Low Externalities, Use CO_2 Internal Cost	$ 34,964	180,655	-	-	-	-	-	10	-	-	1	205,978
No Externalities, Use CO_2 Internal Cost	$ 33,856	192,417	-	-	-	-	-	7	-	-	2	196,381
No Externalities, No CO_2 Internal Cost	$ 33,856	192,417	-	-	-	-	-	7	-	-	2	196,381
Low Solar Price	$ 36,298	166,216	-	-	-	-	-	12	-	-	-	218,561
High Solar Price	$ 37,346	167,852	-	-	1	-	-	4	-	-	3	259,086
Low Wind Price	$ 36,548	154,225	-	-	3	-	-	7	-	-	1	296,880
High Wind Price	$ 36,922	168,999	-	-	-	-	-	12	-	-	-	209,247
Low Forecast	$ 35,943	160,214	-	-	-	-	-	10	-	-	-	239,606
High Forecast	$ 39,699	188,223	-	-	-	-	5	8	-	-	4	172,575
Low Coal Cost	$ 36,873	166,650	-	-	-	-	-	12	-	-	-	217,702
High Coal Cost	$ 36,959	166,650	-	-	-	-	-	12	-	-	-	217,702
Low Gas Price	$ 36,699	179,549	-	-	-	-	-	2	-	-	5	(34,107)
High Gas Price	$ 36,687	148,697	-	-	3	-	-	9	-	-	-	316,863
Low Nuke Cost	$ 36,285	166,650	-	-	-	-	-	12	-	-	-	217,702
High Nuke Cost	$ 37,547	166,650	-	-	-	-	-	12	-	-	-	217,702
High Market Price	$ 36,695	171,092	-	-	1	-	-	11	-	-	-	325,332
Low Market Price	$ 36,834	158,894	-	-	-	-	-	10	-	-	1	109,951
Low Market Capacity	$ 36,999	175,197	-	-	-	-	-	7	-	-	2	121,825
No Market	$ 37,269	180,201	-	-	-	-	-	3	-	-	4	-

Select Strategist Outputs--Standard Assumptions

Scenario 131 KINE_SHEE_MONE_PRAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,038	199,059	-	-	-	-	1	11	-	-	3	132,876
Mid Externalities, No CO_2 Internal Cost	$ 39,522	205,478	-	-	-	-	1	13	-	-	2	148,430
High Externalities, No CO_2 Internal Cost	$ 43,056	202,449	-	-	-	-	1	15	-	-	1	153,835
High Externalities, Use CO_2 Internal Cost	$ 38,891	168,453	-	-	2	-	1	11	-	-	2	240,754
Low Externalities, No CO_2 Internal Cost	$ 35,905	212,403	-	-	-	-	1	11	-	-	3	135,424
Low Externalities, Use CO_2 Internal Cost	$ 34,880	206,850	-	-	-	-	1	11	-	-	3	133,387
No Externalities, Use CO_2 Internal Cost	$ 33,690	213,291	-	-	-	-	1	11	-	-	3	134,544
No Externalities, No CO_2 Internal Cost	$ 33,690	213,291	-	-	-	-	1	11	-	-	3	134,544
Low Solar Price	$ 36,316	190,077	-	-	-	-	1	15	-	-	1	150,724
High Solar Price	$ 37,567	197,286	-	-	1	-	1	5	-	-	5	149,098
Low Wind Price	$ 36,546	165,561	-	-	4	-	1	7	-	-	3	259,589
High Wind Price	$ 37,038	199,059	-	-	-	-	1	11	-	-	3	132,876
Low Forecast	$ 36,041	175,557	-	-	-	-	-	14	-	-	1	193,647
High Forecast	$ 39,966	201,973	-	-	-	-	6	9	-	1	5	139,526
Low Coal Cost	$ 36,995	199,059	-	-	-	-	1	11	-	-	3	132,876
High Coal Cost	$ 37,081	199,059	-	-	-	-	1	11	-	-	3	132,876
Low Gas Price	$ 36,356	211,094	-	-	-	-	1	2	-	-	7	(100,781)
High Gas Price	$ 37,084	165,728	-	-	3	-	1	10	-	-	2	267,910
Low Nuke Cost	$ 36,600	199,059	-	-	-	-	1	11	-	-	3	132,876
High Nuke Cost	$ 37,475	199,059	-	-	-	-	1	11	-	-	3	132,876
High Market Price	$ 36,931	188,606	-	-	1	-	1	12	-	-	2	281,941
Low Market Price	$ 36,801	186,677	-	-	-	-	1	11	-	-	3	34,702
Low Market Capacity	$ 37,090	195,379	-	-	-	-	1	8	-	-	4	84,797
No Market	$ 37,365	190,576	-	-	-	-	1	6	-	-	5	-

Select Strategist Outputs--Standard Assumptions

Scenario 132 KINE_SHEE_MONX_P RAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,267	175,288	-	-	-	-	-	10	-	-	2	208,238
Mid Externalities, No CO_2 Internal Cost	$ 39,869	191,493	-	-	-	-	-	12	-	-	1	190,032
High Externalities, No CO_2 Internal Cost	$ 43,360	178,875	-	-	1	-	-	13	-	-	-	221,380
High Externalities, Use CO_2 Internal Cost	$ 39,010	159,635	-	-	2	-	-	10	-	-	1	272,324
Low Externalities, No CO_2 Internal Cost	$ 36,310	197,588	-	-	-	-	-	10	-	-	2	178,489
Low Externalities, Use CO_2 Internal Cost	$ 35,252	191,825	-	-	-	-	-	10	-	-	2	176,883
No Externalities, Use CO_2 Internal Cost	$ 34,126	201,198	-	-	-	-	-	7	-	-	3	172,648
No Externalities, No CO_2 Internal Cost	$ 34,126	201,198	-	-	-	-	-	7	-	-	3	172,648
Low Solar Price	$ 36,676	178,524	-	-	-	-	-	12	-	-	1	190,357
High Solar Price	$ 37,690	176,225	-	-	1	-	-	4	-	-	4	228,073
Low Wind Price	$ 36,841	153,521	-	-	4	-	-	6	-	-	2	295,465
High Wind Price	$ 37,274	185,507	-	-	-	-	-	10	-	-	2	176,328
Low Forecast	$ 36,289	168,282	-	-	-	-	-	10	-	-	1	222,788
High Forecast	$ 40,050	192,787	-	-	-	-	5	8	-	-	5	163,372
Low Coal Cost	$ 37,224	175,288	-	-	-	-	-	10	-	-	2	208,238
High Coal Cost	$ 37,310	175,288	-	-	-	-	-	10	-	-	2	208,238
Low Gas Price	$ 36,919	196,120	-	-	-	-	-	1	-	-	6	(65,103)
High Gas Price	$ 37,120	151,330	-	-	3	-	-	11	-	-	-	308,289
Low Nuke Cost	$ 36,659	175,288	-	-	-	-	-	10	-	-	2	208,238
High Nuke Cost	$ 37,874	175,288	-	-	-	-	-	10	-	-	2	208,238
High Market Price	$ 37,084	177,064	-	-	1	-	-	11	-	-	1	319,011
Low Market Price	$ 37,134	170,794	-	-	-	-	-	10	-	-	2	81,298
Low Market Capacity	$ 37,353	183,782	-	-	-	-	-	7	-	-	3	105,945
No Market	$ 37,700	182,306	-	-	-	-	-	5	-	-	4	-

Select Strategist Outputs--Standard Assumptions

Scenario 133 KINE_SHEE_MONE_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,031	216,883	-	-	-	-	5	7	-	1	2	81,542
Mid Externalities, No CO_2 Internal Cost	$ 39,344	223,321	-	-	-	-	5	9	-	1	1	100,696
High Externalities, No CO_2 Internal Cost	$ 42,940	219,567	-	-	-	-	5	11	-	1	-	106,965
High Externalities, Use CO_2 Internal Cost	$ 39,059	186,745	-	-	1	-	5	8	-	1	1	176,320
Low Externalities, No CO_2 Internal Cost	$ 35,655	231,355	-	-	-	-	3	9	-	2	1	84,230
Low Externalities, Use CO_2 Internal Cost	$ 34,683	224,134	-	-	-	-	5	7	-	1	2	83,890
No Externalities, Use CO_2 Internal Cost	$ 33,397	231,816	-	-	-	-	3	9	-	2	1	83,426
No Externalities, No CO_2 Internal Cost	$ 33,397	231,816	-	-	-	-	3	9	-	2	1	83,426
Low Solar Price	$ 36,182	206,284	-	-	-	-	5	11	-	1	-	101,784
High Solar Price	$ 37,665	195,896	-	-	2	-	3	5	-	2	2	168,843
Low Wind Price	$ 36,493	171,581	-	2	3	-	5	3	-	-	3	239,259
High Wind Price	$ 37,031	216,883	-	-	-	-	5	7	-	1	2	81,542
Low Forecast	$ 35,954	189,881	-	-	-	-	5	9	-	-	1	145,905
High Forecast	$ 40,052	218,635	-	-	-	-	10	5	-	2	4	92,711
Low Coal Cost	$ 36,988	216,883	-	-	-	-	5	7	-	1	2	81,542
High Coal Cost	$ 37,074	216,883	-	-	-	-	5	7	-	1	2	81,542
Low Gas Price	$ 35,979	249,231	-	-	-	-	1	-	-	3	5	(195,985)
High Gas Price	$ 37,278	178,906	-	-	4	-	5	6	-	1	1	230,454
Low Nuke Cost	$ 36,793	216,883	-	-	-	-	5	7	-	1	2	81,542
High Nuke Cost	$ 37,270	216,883	-	-	-	-	5	7	-	1	2	81,542
High Market Price	$ 37,044	204,282	-	-	1	-	5	8	-	1	1	240,541
Low Market Price	$ 36,660	205,624	-	-	-	-	5	7	-	1	2	(19,558)
Low Market Capacity	$ 37,064	211,827	-	-	-	-	5	5	-	1	3	49,552
No Market	$ 37,290	205,625	-	-	1	-	3	4	-	2	3	-

Select Strategist Outputs--Standard Assumptions

Scenario 134 KINE_SHEE_MONE_PRAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 36,814	171,071	-	-	-	-	1	11	-	-	-	202,183
Mid Externalities, No CO_2 Internal Cost	$ 39,358	185,511	-	-	-	-	1	11	-	-	-	196,934
High Externalities, No CO_2 Internal Cost	$ 42,857	185,511	-	-	-	-	1	11	-	-	-	196,934
High Externalities, Use CO_2 Internal Cost	$ 38,574	160,347	-	-	1	-	1	10	-	-	-	255,447
Low Externalities, No CO_2 Internal Cost	$ 35,853	190,907	-	-	-	-	1	9	-	-	1	192,824
Low Externalities, Use CO_2 Internal Cost	$ 34,794	185,482	-	-	-	-	1	9	-	-	1	190,847
No Externalities, Use CO_2 Internal Cost	$ 33,654	197,034	-	-	-	-	1	6	-	-	2	182,427
No Externalities, No CO_2 Internal Cost	$ 33,654	197,034	-	-	-	-	1	6	-	-	2	182,427
Low Solar Price	$ 36,190	170,637	-	-	-	-	1	11	-	-	-	203,041
High Solar Price	$ 37,251	172,308	-	-	1	-	1	3	-	-	3	243,416
Low Wind Price	$ 36,444	158,651	-	-	3	-	1	6	-	-	1	281,709
High Wind Price	$ 36,819	173,420	-	-	-	-	1	11	-	-	-	193,728
Low Forecast	$ 35,829	164,727	-	-	-	-	-	10	-	-	-	223,673
High Forecast	$ 39,705	192,005	-	-	-	-	6	7	-	1	3	160,875
Low Coal Cost	$ 36,771	171,071	-	-	-	-	1	11	-	-	-	202,183
High Coal Cost	$ 36,857	171,071	-	-	-	-	1	11	-	-	-	202,183
Low Gas Price	$ 36,472	187,315	-	-	-	-	-	1	-	1	4	(61,844)
High Gas Price	$ 36,657	153,210	-	-	3	-	1	8	-	-	-	301,932
Low Nuke Cost	$ 36,238	171,071	-	-	-	-	1	11	-	-	-	202,183
High Nuke Cost	$ 37,389	171,071	-	-	-	-	1	11	-	-	-	202,183
High Market Price	$ 36,629	175,809	-	-	1	-	1	10	-	-	-	312,217
Low Market Price	$ 36,690	163,574	-	-	-	-	1	9	-	-	1	91,928
Low Market Capacity	$ 36,847	179,344	-	-	-	-	1	6	-	-	2	113,121
No Market	$ 37,053	183,794	-	-	-	-	1	2	-	-	4	-

Select Strategist Outputs--Standard Assumptions

Scenario 135 KINE_SHEE_MONX_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,273	190,327	-	-	-	-	3	7	-	-	2	157,650
Mid Externalities, No CO_2 Internal Cost	$ 39,698	204,029	-	-	-	-	3	11	-	-	-	143,560
High Externalities, No CO_2 Internal Cost	$ 43,213	201,479	-	-	-	-	3	11	-	-	-	147,686
High Externalities, Use CO_2 Internal Cost	$ 39,178	172,689	-	-	1	-	3	8	-	-	1	223,758
Low Externalities, No CO_2 Internal Cost	$ 36,080	213,696	-	-	-	-	3	7	-	-	2	130,348
Low Externalities, Use CO_2 Internal Cost	$ 35,063	207,565	-	-	-	-	3	7	-	-	2	127,802
No Externalities, Use CO_2 Internal Cost	$ 33,846	214,137	-	-	-	-	3	7	-	-	2	129,619
No Externalities, No CO_2 Internal Cost	$ 33,846	214,137	-	-	-	-	3	7	-	-	2	129,619
Low Solar Price	$ 36,518	188,536	-	-	-	-	3	11	-	-	-	142,603
High Solar Price	$ 37,809	188,723	-	-	1	-	3	4	-	-	3	181,013
Low Wind Price	$ 36,809	162,555	-	2	2	-	2	5	-	-	2	264,815
High Wind Price	$ 37,279	200,546	-	-	-	-	3	7	-	-	2	125,740
Low Forecast	$ 36,245	182,136	-	-	-	-	2	8	-	-	1	172,774
High Forecast	$ 40,266	206,889	-	-	-	-	8	5	-	1	4	117,865
Low Coal Cost	$ 37,230	190,327	-	-	-	-	3	7	-	-	2	157,650
High Coal Cost	$ 37,315	190,327	-	-	-	-	3	7	-	-	2	157,650
Low Gas Price	$ 36,567	211,905	-	-	-	-	-	2	-	2	4	(116,151)
High Gas Price	$ 37,320	164,276	-	-	3	-	3	9	-	-	-	264,435
Low Nuke Cost	$ 36,854	190,327	-	-	-	-	3	7	-	-	2	157,650
High Nuke Cost	$ 37,692	190,327	-	-	-	-	3	7	-	-	2	157,650
High Market Price	$ 37,200	190,533	-	-	1	-	3	8	-	-	1	278,116
Low Market Price	$ 37,008	187,524	-	-	-	-	3	7	-	-	2	24,638
Low Market Capacity	$ 37,285	198,740	-	-	-	-	3	5	-	-	3	72,936
No Market	$ 37,507	196,423	-	-	-	-	3	3	-	-	4	-

Select Strategist Outputs--Standard Assumptions

Scenario 136 KINE_SHEE_MONX_P RAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 37,075	162,414	-	-	-	-	-	8	-	-	-	241,330
Mid Externalities, No CO_2 Internal Cost	$ 39,752	176,011	-	-	-	-	-	8	-	-	-	235,572
High Externalities, No CO_2 Internal Cost	$ 43,231	173,381	-	-	-	-	-	8	-	-	-	243,195
High Externalities, Use CO_2 Internal Cost	$ 38,740	152,518	-	-	1	-	-	7	-	-	-	291,358
Low Externalities, No CO_2 Internal Cost	$ 36,272	176,011	-	-	-	-	-	8	-	-	-	235,572
Low Externalities, Use CO_2 Internal Cost	$ 35,190	176,638	-	-	-	-	-	5	-	-	1	228,481
No Externalities, Use CO_2 Internal Cost	$ 34,116	182,793	-	-	-	-	-	5	-	-	1	229,578
No Externalities, No CO_2 Internal Cost	$ 34,116	182,793	-	-	-	-	-	5	-	-	1	229,578
Low Solar Price	$ 36,609	162,144	-	-	-	-	-	8	-	-	-	240,564
High Solar Price	$ 37,434	164,294	-	-	1	-	-	2	-	-	2	271,979
Low Wind Price	$ 36,761	148,176	-	-	3	-	-	5	-	-	-	311,051
High Wind Price	$ 37,081	164,764	-	-	-	-	-	8	-	-	-	232,875
Low Forecast	$ 36,122	156,612	-	-	-	-	-	6	-	-	-	266,274
High Forecast	$ 39,833	179,034	-	-	-	-	5	5	-	-	3	203,340
Low Coal Cost	$ 37,033	162,414	-	-	-	-	-	8	-	-	-	241,330
High Coal Cost	$ 37,118	162,414	-	-	-	-	-	8	-	-	-	241,330
Low Gas Price	$ 37,069	164,339	-	-	-	-	-	1	-	-	3	8,941
High Gas Price	$ 36,766	147,762	-	-	2	-	-	6	-	-	-	324,125
Low Nuke Cost	$ 36,336	162,414	-	-	-	-	-	8	-	-	-	241,330
High Nuke Cost	$ 37,815	162,414	-	-	-	-	-	8	-	-	-	241,330
High Market Price	$ 36,816	169,961	-	-	-	-	-	8	-	-	-	333,790
Low Market Price	$ 37,050	148,473	-	-	-	-	-	8	-	-	-	144,289
Low Market Capacity	$ 37,166	166,155	-	-	-	-	-	5	-	-	1	143,417
No Market	$ 37,467	167,744	-	-	-	-	-	1	-	-	3	-

Docket No. E002/RP- 19-368

Attachment 2

Select Strategist Outputs--High Energy Efficiency

Select Strategist Outputs--High Energy Efficiency

Scenario 201 KINN_SHEN_MONN_PRAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,887	184,968	-	-	-	-	-	7	-	-	-	212,611
Mid Externalities, No CO_2 Internal Cost	$ 42,342	216,698	-	-	-	-	-	7	-	-	-	210,353
High Externalities, No CO_2 Internal Cost	$ 46,481	206,102	-	-	-	-	-	7	-	-	-	235,333
High Externalities, Use CO_2 Internal Cost	$ 40,722	172,884	-	-	1	-	-	6	-	-	-	244,619
Low Externalities, No CO_2 Internal Cost	$ 38,151	221,455	-	-	-	-	-	7	-	-	-	203,165
Low Externalities, Use CO_2 Internal Cost	$ 36,695	209,082	-	-	-	-	-	7	-	-	-	196,489
No Externalities, Use CO_2 Internal Cost	$ 35,520	222,155	-	-	-	-	-	5	-	-	1	203,032
No Externalities, No CO_2 Internal Cost	$ 35,520	222,155	-	-	-	-	-	5	-	-	1	203,032
Low Solar Price	$ 38,404	179,923	-	-	-	-	-	7	-	-	-	221,576
High Solar Price	$ 39,250	180,157	-	-	2	-	-	3	-	-	1	252,375
Low Wind Price	$ 38,534	165,689	-	-	3	-	-	5	-	-	-	296,281
High Wind Price	$ 38,892	190,100	-	-	-	-	-	7	-	-	-	195,505
Low Forecast	$ 37,853	175,872	-	-	-	-	-	5	-	-	-	234,388
High Forecast	$ 41,397	201,579	-	-	-	-	-	12	-	-	2	176,160
Low Coal Cost	$ 38,813	184,968	-	-	-	-	-	7	-	-	-	212,611
High Coal Cost	$ 38,961	184,968	-	-	-	-	-	7	-	-	-	212,611
Low Gas Price	$ 38,513	191,578	-	-	-	-	-	1	-	-	3	(27,460)
High Gas Price	$ 38,846	168,002	-	-	3	-	-	5	-	-	-	306,671
Low Nuke Cost	$ 38,394	184,968	-	-	-	-	-	7	-	-	-	212,611
High Nuke Cost	$ 39,380	184,968	-	-	-	-	-	7	-	-	-	212,611
High Market Price	$ 38,677	190,909	-	-	1	-	-	6	-	-	-	311,367
Low Market Price	$ 38,773	178,450	-	-	-	-	-	7	-	-	-	87,702
Low Market Capacity	$ 38,954	189,157	-	-	-	-	-	7	-	-	-	118,116
No Market	$ 39,298	201,198	-	-	-	-	-	5	-	-	1	-

Select Strategist Outputs--High Energy Efficiency

Scenario 202 KINE_SHEN_MONN_P RAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,746	177,387	-	-	-	-	-	8	-	-	1	222,151
Mid Externalities, No CO_2 Internal Cost	$ 41,688	196,397	-	-	-	-	-	11	-	-	-	206,219
High Externalities, No CO_2 Internal Cost	$ 45,450	196,397	-	-	-	-	-	11	-	-	-	206,219
High Externalities, Use CO_2 Internal Cost	$ 40,545	168,140	-	-	2	-	-	9	-	-	-	253,156
Low Externalities, No CO_2 Internal Cost	$ 37,867	203,241	-	-	-	-	-	8	-	-	1	198,285
Low Externalities, Use CO_2 Internal Cost	$ 36,614	197,046	-	-	-	-	-	8	-	-	1	196,060
No Externalities, Use CO_2 Internal Cost	$ 35,475	208,148	-	-	-	-	-	6	-	-	2	188,972
No Externalities, No CO_2 Internal Cost	$ 35,475	208,148	-	-	-	-	-	6	-	-	2	188,972
Low Solar Price	$ 38,164	180,968	-	-	-	-	-	11	-	-	-	200,954
High Solar Price	$ 39,147	175,247	-	-	1	-	-	5	-	-	2	255,427
Low Wind Price	$ 38,345	157,251	-	-	4	-	-	7	-	-	-	306,885
High Wind Price	$ 38,749	183,606	-	-	-	-	-	11	-	-	-	199,087
Low Forecast	$ 37,688	175,038	-	-	-	-	-	8	-	-	-	218,230
High Forecast	$ 41,351	199,208	-	-	-	-	2	9	-	-	4	169,269
Low Coal Cost	$ 38,695	177,387	-	-	-	-	-	8	-	-	1	222,151
High Coal Cost	$ 38,797	177,387	-	-	-	-	-	8	-	-	1	222,151
Low Gas Price	$ 38,409	194,162	-	-	-	-	-	2	-	-	4	(36,402)
High Gas Price	$ 38,649	159,233	-	-	3	-	-	8	-	-	-	316,982
Low Nuke Cost	$ 38,253	177,387	-	-	-	-	-	8	-	-	1	222,151
High Nuke Cost	$ 39,238	177,387	-	-	-	-	-	8	-	-	1	222,151
High Market Price	$ 38,525	186,069	-	-	-	-	-	8	-	-	1	307,692
Low Market Price	$ 38,640	173,648	-	-	-	-	-	8	-	-	1	98,203
Low Market Capacity	$ 38,843	197,092	-	-	-	-	-	6	-	-	2	96,446
No Market	$ 39,201	197,536	-	-	-	-	-	4	-	-	3	-

Select Strategist Outputs--High Energy Efficiency

Scenario 203 KINN_SHEE_MONN_P RAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,728	173,701	-	-	-	-	-	11	-	-	-	209,376
Mid Externalities, No CO_2 Internal Cost	$ 41,759	199,315	-	-	-	-	-	11	-	-	-	204,319
High Externalities, No CO_2 Internal Cost	$ 45,528	199,315	-	-	-	-	-	11	-	-	-	204,319
High Externalities, Use CO_2 Internal Cost	$ 40,471	162,908	-	-	2	-	-	9	-	-	-	246,861
Low Externalities, No CO_2 Internal Cost	$ 37,968	201,225	-	-	-	-	-	11	-	-	-	202,584
Low Externalities, Use CO_2 Internal Cost	$ 36,715	197,479	-	-	-	-	-	6	-	-	2	187,891
No Externalities, Use CO_2 Internal Cost	$ 35,578	209,500	-	-	-	-	-	6	-	-	2	194,240
No Externalities, No CO_2 Internal Cost	$ 35,578	209,500	-	-	-	-	-	6	-	-	2	194,240
Low Solar Price	$ 38,162	176,977	-	-	-	-	-	11	-	-	-	193,962
High Solar Price	$ 39,129	172,254	-	-	1	-	-	3	-	-	3	244,163
Low Wind Price	$ 38,326	153,496	-	-	4	-	-	5	-	-	1	300,490
High Wind Price	$ 38,733	178,833	-	-	-	-	-	11	-	-	-	192,271
Low Forecast	$ 37,694	164,680	-	-	1	-	-	7	-	-	-	238,598
High Forecast	$ 41,307	193,542	-	-	-	-	-	12	-	-	4	169,139
Low Coal Cost	$ 38,662	173,701	-	-	-	-	-	11	-	-	-	209,376
High Coal Cost	$ 38,794	173,701	-	-	-	-	-	11	-	-	-	209,376
Low Gas Price	$ 38,362	184,144	-	-	-	-	-	2	-	-	4	(34,134)
High Gas Price	$ 38,615	153,920	-	-	3	-	-	8	-	-	-	308,589
Low Nuke Cost	$ 38,235	173,701	-	-	-	-	-	11	-	-	-	209,376
High Nuke Cost	$ 39,221	173,701	-	-	-	-	-	11	-	-	-	209,376
High Market Price	$ 38,518	181,098	-	-	1	-	-	10	-	-	-	304,377
Low Market Price	$ 38,621	169,661	-	-	-	-	-	9	-	-	1	84,871
Low Market Capacity	$ 38,809	180,993	-	-	-	-	-	6	-	-	2	113,955
No Market	$ 39,163	193,990	-	-	-	-	-	4	-	-	3	-

Select Strategist Outputs--High Energy Efficiency

Scenario 204 KINN_SHEN_MONE_PRAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,773	189,517	-	-	-	-	-	7	-	-	-	197,421
Mid Externalities, No CO_2 Internal Cost	$ 42,221	222,276	-	-	-	-	-	7	-	-	-	196,507
High Externalities, No CO_2 Internal Cost	$ 46,422	211,680	-	-	-	-	-	7	-	-	-	221,487
High Externalities, Use CO_2 Internal Cost	$ 40,673	177,276	-	-	1	-	-	6	-	-	-	229,489
Low Externalities, No CO_2 Internal Cost	$ 37,967	227,033	-	-	-	-	-	7	-	-	-	189,319
Low Externalities, Use CO_2 Internal Cost	$ 36,509	214,360	-	-	-	-	-	7	-	-	-	182,045
No Externalities, Use CO_2 Internal Cost	$ 35,299	227,734	-	-	-	-	-	5	-	-	1	189,186
No Externalities, No CO_2 Internal Cost	$ 35,299	227,734	-	-	-	-	-	5	-	-	1	189,186
Low Solar Price	$ 38,290	184,472	-	-	-	-	-	7	-	-	-	206,386
High Solar Price	$ 39,136	184,706	-	-	2	-	-	3	-	-	1	237,185
Low Wind Price	$ 38,420	170,238	-	-	3	-	-	5	-	-	-	281,091
High Wind Price	$ 38,778	194,649	-	-	-	-	-	7	-	-	-	180,315
Low Forecast	$ 37,736	180,323	-	-	-	-	-	5	-	-	-	219,932
High Forecast	$ 41,395	204,006	-	-	-	-	3	9	-	-	2	167,263
Low Coal Cost	$ 38,699	189,517	-	-	-	-	-	7	-	-	-	197,421
High Coal Cost	$ 38,847	189,517	-	-	-	-	-	7	-	-	-	197,421
Low Gas Price	$ 38,271	196,700	-	-	-	-	-	1	-	-	3	(47,303)
High Gas Price	$ 38,811	172,764	-	-	3	-	-	5	-	-	-	291,932
Low Nuke Cost	$ 38,336	189,517	-	-	-	-	-	7	-	-	-	197,421
High Nuke Cost	$ 39,211	189,517	-	-	-	-	-	7	-	-	-	197,421
High Market Price	$ 38,601	196,030	-	-	1	-	-	6	-	-	-	298,968
Low Market Price	$ 38,617	183,013	-	-	-	-	-	7	-	-	-	69,380
Low Market Capacity	$ 38,775	193,276	-	-	-	-	-	7	-	-	-	110,416
No Market	$ 39,036	204,567	-	-	-	-	-	5	-	-	1	-

Select Strategist Outputs--High Energy Efficiency

Scenario 205 KINN_SHEN_MONX_PRAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 39,101	174,538	-	-	-	-	-	3	-	-	-	247,684
Mid Externalities, No CO_2 Internal Cost	$ 42,639	198,899	-	-	-	-	-	3	-	-	-	261,640
High Externalities, No CO_2 Internal Cost	$ 46,747	198,899	-	-	-	-	-	3	-	-	-	261,640
High Externalities, Use CO_2 Internal Cost	$ 40,868	166,823	-	-	1	-	-	2	-	-	-	269,690
Low Externalities, No CO_2 Internal Cost	$ 38,470	210,620	-	-	-	-	-	3	-	-	-	233,266
Low Externalities, Use CO_2 Internal Cost	$ 37,000	198,258	-	-	-	-	-	3	-	-	-	226,906
No Externalities, Use CO_2 Internal Cost	$ 35,866	213,628	-	-	-	-	-	3	-	-	-	227,833
No Externalities, No CO_2 Internal Cost	$ 35,866	213,628	-	-	-	-	-	3	-	-	-	227,833
Low Solar Price	$ 38,707	173,146	-	-	-	-	-	3	-	-	-	248,916
High Solar Price	$ 39,401	173,215	-	-	1	-	-	2	-	-	-	275,076
Low Wind Price	$ 38,787	162,824	-	-	2	-	-	1	-	-	-	306,808
High Wind Price	$ 39,117	182,547	-	-	-	-	-	3	-	-	-	222,457
Low Forecast	$ 38,100	169,741	-	-	-	-	-	1	-	-	-	256,212
High Forecast	$ 41,545	193,707	-	-	-	-	-	10	-	-	1	199,458
Low Coal Cost	$ 39,027	174,538	-	-	-	-	-	3	-	-	-	247,684
High Coal Cost	$ 39,175	174,538	-	-	-	-	-	3	-	-	-	247,684
Low Gas Price	$ 38,953	178,027	-	-	-	-	-	1	-	-	1	6,097
High Gas Price	$ 38,931	163,506	-	-	2	-	-	1	-	-	-	323,276
Low Nuke Cost	$ 38,494	174,538	-	-	-	-	-	3	-	-	-	247,684
High Nuke Cost	$ 39,709	174,538	-	-	-	-	-	3	-	-	-	247,684
High Market Price	$ 38,836	184,318	-	-	1	-	-	2	-	-	-	332,975
Low Market Price	$ 39,054	165,680	-	-	-	-	-	3	-	-	-	126,252
Low Market Capacity	$ 39,190	182,701	-	-	-	-	-	3	-	-	-	133,205
No Market	$ 39,555	186,226	-	-	-	-	-	1	-	-	1	-

Select Strategist Outputs--High Energy Efficiency

Scenario 206 KINN_SHEN_MONN_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,735	193,946	-	-	-	-	-	7	-	-	-	188,835
Mid Externalities, No CO_2 Internal Cost	$ 42,119	239,534	-	-	-	-	-	7	-	-	-	155,161
High Externalities, No CO_2 Internal Cost	$ 46,482	222,585	-	-	-	-	-	7	-	-	-	208,334
High Externalities, Use CO_2 Internal Cost	$ 40,748	183,088	-	-	2	-	-	6	-	-	-	221,056
Low Externalities, No CO_2 Internal Cost	$ 37,743	239,534	-	-	-	-	-	7	-	-	-	155,161
Low Externalities, Use CO_2 Internal Cost	$ 36,313	226,540	-	-	-	-	-	7	-	-	-	146,346
No Externalities, Use CO_2 Internal Cost	$ 35,035	239,534	-	-	-	-	-	7	-	-	-	155,161
No Externalities, No CO_2 Internal Cost	$ 35,035	239,534	-	-	-	-	-	7	-	-	-	155,161
Low Solar Price	$ 38,246	193,946	-	-	-	-	-	7	-	-	-	188,835
High Solar Price	$ 39,158	195,874	-	-	1	-	-	6	-	-	-	197,123
Low Wind Price	$ 38,250	172,939	-	-	5	-	-	3	-	-	-	262,972
High Wind Price	$ 38,739	210,173	-	-	-	-	-	7	-	-	-	134,641
Low Forecast	$ 37,707	188,802	-	-	-	-	-	5	-	-	-	205,632
High Forecast	$ 41,523	216,987	-	-	-	-	4	8	-	1	1	130,838
Low Coal Cost	$ 38,661	193,946	-	-	-	-	-	7	-	-	-	188,835
High Coal Cost	$ 38,809	193,946	-	-	-	-	-	7	-	-	-	188,835
Low Gas Price	$ 37,950	213,407	-	-	-	-	-	3	-	-	2	(96,042)
High Gas Price	$ 38,881	177,691	-	-	3	-	-	5	-	-	-	274,666
Low Nuke Cost	$ 38,436	193,946	-	-	-	-	-	7	-	-	-	188,835
High Nuke Cost	$ 39,034	193,946	-	-	-	-	-	7	-	-	-	188,835
High Market Price	$ 38,645	210,161	-	-	-	-	-	7	-	-	-	262,775
Low Market Price	$ 38,464	195,628	-	-	-	-	-	7	-	-	-	28,556
Low Market Capacity	$ 38,675	204,574	-	-	-	-	-	7	-	-	-	85,485
No Market	$ 38,839	217,667	-	-	-	-	-	5	-	-	1	-

Select Strategist Outputs--High Energy Efficiency

Scenario 207 KINN_SHEN_MONN_PRAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,719	172,150	-	-	-	-	-	-	-	-	-	263,281
Mid Externalities, No CO_2 Internal Cost	$ 42,344	198,979	-	-	-	-	-	-	-	-	-	277,146
High Externalities, No CO_2 Internal Cost	$ 46,533	198,979	-	-	-	-	-	-	-	-	-	277,146
High Externalities, Use CO_2 Internal Cost	$ 40,516	168,448	-	-	-	-	-	-	-	-	-	265,783
Low Externalities, No CO_2 Internal Cost	$ 38,132	209,714	-	-	-	-	-	-	-	-	-	244,102
Low Externalities, Use CO_2 Internal Cost	$ 36,627	197,022	-	-	-	-	-	-	-	-	-	237,384
No Externalities, Use CO_2 Internal Cost	$ 35,486	209,714	-	-	-	-	-	-	-	-	-	244,102
No Externalities, No CO_2 Internal Cost	$ 35,486	209,714	-	-	-	-	-	-	-	-	-	244,102
Low Solar Price	$ 38,452	172,150	-	-	-	-	-	-	-	-	-	263,281
High Solar Price	$ 38,965	174,021	-	-	-	-	-	-	-	-	-	274,253
Low Wind Price	$ 38,518	164,317	-	-	-	-	-	-	-	-	-	298,921
High Wind Price	$ 38,775	182,182	-	-	-	-	-	-	-	-	-	228,573
Low Forecast	$ 37,770	170,163	-	-	-	-	-	-	-	-	-	263,389
High Forecast	$ 41,170	188,023	-	-	-	-	-	10	-	-	-	206,039
Low Coal Cost	$ 38,645	172,150	-	-	-	-	-	-	-	-	-	263,281
High Coal Cost	$ 38,793	172,150	-	-	-	-	-	-	-	-	-	263,281
Low Gas Price	$ 38,668	168,420	-	-	-	-	-	-	-	-	-	19,085
High Gas Price	$ 38,637	168,988	-	-	-	-	-	-	-	-	-	310,100
Low Nuke Cost	$ 38,088	172,150	-	-	-	-	-	-	-	-	-	263,281
High Nuke Cost	$ 39,349	172,150	-	-	-	-	-	-	-	-	-	263,281
High Market Price	$ 38,455	187,380	-	-	-	-	-	-	-	-	-	331,790
Low Market Price	$ 38,706	162,576	-	-	-	-	-	-	-	-	-	125,634
Low Market Capacity	$ 38,742	177,674	-	-	-	-	-	-	-	-	-	146,265
No Market	$ 39,035	175,377	-	-	-	-	-	-	-	-	-	-

Select Strategist Outputs--High Energy Efficiency

Scenario 208 KINE_SHEN_MONE_PRAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,633	181,883	-	-	-	-	-	8	-	-	1	206,864
Mid Externalities, No CO_2 Internal Cost	$ 41,555	201,627	-	-	-	-	-	11	-	-	-	191,818
High Externalities, No CO_2 Internal Cost	$ 45,371	201,627	-	-	-	-	-	11	-	-	-	191,818
High Externalities, Use CO_2 Internal Cost	$ 40,497	172,537	-	-	2	-	-	9	-	-	-	238,020
Low Externalities, No CO_2 Internal Cost	$ 37,680	208,471	-	-	-	-	-	8	-	-	1	183,884
Low Externalities, Use CO_2 Internal Cost	$ 36,430	202,110	-	-	-	-	-	8	-	-	1	181,332
No Externalities, Use CO_2 Internal Cost	$ 35,257	213,378	-	-	-	-	-	6	-	-	2	174,571
No Externalities, No CO_2 Internal Cost	$ 35,257	213,378	-	-	-	-	-	6	-	-	2	174,571
Low Solar Price	$ 38,051	185,464	-	-	-	-	-	11	-	-	-	185,667
High Solar Price	$ 39,034	179,743	-	-	1	-	-	5	-	-	2	240,140
Low Wind Price	$ 38,232	161,747	-	-	4	-	-	7	-	-	-	291,598
High Wind Price	$ 38,636	188,101	-	-	-	-	-	11	-	-	-	183,800
Low Forecast	$ 37,570	179,423	-	-	-	-	-	8	-	-	-	203,645
High Forecast	$ 41,344	200,263	-	-	-	-	6	5	-	-	4	161,566
Low Coal Cost	$ 38,582	181,883	-	-	-	-	-	8	-	-	1	206,864
High Coal Cost	$ 38,684	181,883	-	-	-	-	-	8	-	-	1	206,864
Low Gas Price	$ 38,168	199,277	-	-	-	-	-	2	-	-	4	(56,171)
High Gas Price	$ 38,615	163,904	-	-	3	-	-	8	-	-	-	302,054
Low Nuke Cost	$ 38,196	181,883	-	-	-	-	-	8	-	-	1	206,864
High Nuke Cost	$ 39,071	181,883	-	-	-	-	-	8	-	-	1	206,864
High Market Price	$ 38,450	191,032	-	-	-	-	-	8	-	-	1	295,063
Low Market Price	$ 38,486	178,206	-	-	-	-	-	8	-	-	1	79,876
Low Market Capacity	$ 38,665	201,153	-	-	-	-	-	6	-	-	2	88,576
No Market	$ 38,940	200,888	-	-	-	-	-	4	-	-	3	-

Select Strategist Outputs--High Energy Efficiency

Scenario 209 KINE_SHEN_MONX_PRAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,918	173,268	-	-	-	-	-	6	-	-	-	236,673
Mid Externalities, No CO_2 Internal Cost	$ 41,960	192,468	-	-	-	-	-	6	-	-	-	229,000
High Externalities, No CO_2 Internal Cost	$ 45,743	183,242	-	-	-	-	-	6	-	-	-	254,205
High Externalities, Use CO_2 Internal Cost	$ 40,664	162,321	-	-	1	-	-	6	-	-	-	274,215
Low Externalities, No CO_2 Internal Cost	$ 38,143	194,172	-	-	-	-	-	6	-	-	-	225,729
Low Externalities, Use CO_2 Internal Cost	$ 36,869	187,959	-	-	-	-	-	6	-	-	-	223,430
No Externalities, Use CO_2 Internal Cost	$ 35,764	201,433	-	-	-	-	-	4	-	-	1	209,954
No Externalities, No CO_2 Internal Cost	$ 35,764	201,433	-	-	-	-	-	4	-	-	1	209,954
Low Solar Price	$ 38,475	167,985	-	-	-	-	-	6	-	-	-	248,900
High Solar Price	$ 39,251	169,522	-	-	1	-	-	3	-	-	1	274,824
Low Wind Price	$ 38,603	158,036	-	-	3	-	-	4	-	-	-	309,518
High Wind Price	$ 38,923	177,022	-	-	-	-	-	6	-	-	-	223,834
Low Forecast	$ 37,892	164,887	-	-	-	-	-	4	-	-	-	256,873
High Forecast	$ 41,463	190,430	-	-	-	-	2	7	-	-	3	196,875
Low Coal Cost	$ 38,867	173,268	-	-	-	-	-	6	-	-	-	236,673
High Coal Cost	$ 38,969	173,268	-	-	-	-	-	6	-	-	-	236,673
Low Gas Price	$ 38,807	176,397	-	-	-	-	-	2	-	-	2	10,273
High Gas Price	$ 38,718	155,981	-	-	2	-	-	5	-	-	-	327,466
Low Nuke Cost	$ 38,310	173,268	-	-	-	-	-	6	-	-	-	236,673
High Nuke Cost	$ 39,525	173,268	-	-	-	-	-	6	-	-	-	236,673
High Market Price	$ 38,658	178,413	-	-	-	-	-	6	-	-	-	328,587
Low Market Price	$ 38,878	162,050	-	-	-	-	-	6	-	-	-	132,168
Low Market Capacity	$ 39,029	178,942	-	-	-	-	-	4	-	-	1	132,478
No Market	$ 39,414	183,276	-	-	-	-	-	2	-	-	2	-

Select Strategist Outputs--High Energy Efficiency

Scenario 210 KINE_SHEN_MONN_P RAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,603	191,222	-	-	-	-	1	10	-	-	-	171,947
Mid Externalities, No CO_2 Internal Cost	$ 41,436	218,697	-	-	-	-	1	10	-	-	-	151,018
High Externalities, No CO_2 Internal Cost	$ 45,362	208,239	-	-	-	-	1	10	-	-	-	180,166
High Externalities, Use CO_2 Internal Cost	$ 40,580	181,874	-	-	1	-	1	9	-	-	-	203,525
Low Externalities, No CO_2 Internal Cost	$ 37,491	218,697	-	-	-	-	1	10	-	-	-	151,018
Low Externalities, Use CO_2 Internal Cost	$ 36,281	212,093	-	-	-	-	1	10	-	-	-	147,629
No Externalities, Use CO_2 Internal Cost	$ 35,035	224,998	-	-	-	-	1	7	-	-	1	140,858
No Externalities, No CO_2 Internal Cost	$ 35,035	224,998	-	-	-	-	1	7	-	-	1	140,858
Low Solar Price	$ 37,979	191,222	-	-	-	-	1	10	-	-	-	171,947
High Solar Price	$ 39,097	191,785	-	-	1	-	1	4	-	-	2	202,568
Low Wind Price	$ 38,146	165,779	-	1	4	-	-	6	-	-	-	272,764
High Wind Price	$ 38,607	201,495	-	-	-	-	1	10	-	-	-	142,762
Low Forecast	$ 37,529	183,004	-	-	-	-	-	9	-	-	-	192,309
High Forecast	$ 41,473	213,196	-	-	-	-	6	8	-	1	2	124,451
Low Coal Cost	$ 38,552	191,222	-	-	-	-	1	10	-	-	-	171,947
High Coal Cost	$ 38,655	191,222	-	-	-	-	1	10	-	-	-	171,947
Low Gas Price	$ 37,888	214,739	-	-	-	-	1	3	-	-	3	(101,145)
High Gas Price	$ 38,710	171,899	-	-	3	-	1	7	-	-	-	275,279
Low Nuke Cost	$ 38,304	191,222	-	-	-	-	1	10	-	-	-	171,947
High Nuke Cost	$ 38,903	191,222	-	-	-	-	1	10	-	-	-	171,947
High Market Price	$ 38,503	199,365	-	-	1	-	1	9	-	-	-	267,931
Low Market Price	$ 38,368	189,090	-	-	-	-	1	10	-	-	-	42,547
Low Market Capacity	$ 38,603	211,850	-	-	-	-	1	7	-	-	1	64,343
No Market	$ 38,779	212,107	-	-	-	-	1	5	-	-	2	-

Select Strategist Outputs--High Energy Efficiency

Scenario 211 KINE_SHEN_MONN_PRAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,527	167,875	-	-	-	-	-	4	-	-	-	253,173
Mid Externalities, No CO_2 Internal Cost	$ 41,608	184,436	-	-	-	-	-	4	-	-	-	252,141
High Externalities, No CO_2 Internal Cost	$ 45,426	184,436	-	-	-	-	-	4	-	-	-	252,141
High Externalities, Use CO_2 Internal Cost	$ 40,277	161,609	-	-	1	-	-	3	-	-	-	280,290
Low Externalities, No CO_2 Internal Cost	$ 37,786	186,129	-	-	-	-	-	4	-	-	-	246,823
Low Externalities, Use CO_2 Internal Cost	$ 36,503	180,099	-	-	-	-	-	4	-	-	-	244,623
No Externalities, Use CO_2 Internal Cost	$ 35,415	190,531	-	-	-	-	-	4	-	-	-	242,136
No Externalities, No CO_2 Internal Cost	$ 35,415	190,531	-	-	-	-	-	4	-	-	-	242,136
Low Solar Price	$ 38,142	169,096	-	-	-	-	-	4	-	-	-	246,884
High Solar Price	$ 38,853	167,413	-	-	1	-	-	3	-	-	-	284,020
Low Wind Price	$ 38,235	149,458	-	-	3	-	-	1	-	-	-	329,251
High Wind Price	$ 38,533	170,782	-	-	-	-	-	4	-	-	-	241,521
Low Forecast	$ 37,554	164,952	-	-	-	-	-	2	-	-	-	266,218
High Forecast	$ 41,108	184,276	-	-	-	-	2	9	-	-	1	207,515
Low Coal Cost	$ 38,476	167,875	-	-	-	-	-	4	-	-	-	253,173
High Coal Cost	$ 38,578	167,875	-	-	-	-	-	4	-	-	-	253,173
Low Gas Price	$ 38,568	166,413	-	-	-	-	-	2	-	-	1	26,279
High Gas Price	$ 38,301	157,137	-	-	2	-	-	2	-	-	-	327,270
Low Nuke Cost	$ 37,896	167,875	-	-	-	-	-	4	-	-	-	253,173
High Nuke Cost	$ 39,158	167,875	-	-	-	-	-	4	-	-	-	253,173
High Market Price	$ 38,251	178,688	-	-	-	-	-	4	-	-	-	333,859
Low Market Price	$ 38,517	154,372	-	-	-	-	-	4	-	-	-	149,761
Low Market Capacity	$ 38,611	170,319	-	-	-	-	-	4	-	-	-	148,890
No Market	$ 38,938	170,664	-	-	-	-	-	2	-	-	1	-

Select Strategist Outputs--High Energy Efficiency

Scenario 212 KINE_SHEE_MONN_PRAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,621	167,498	-	-	-	-	-	12	-	-	1	217,592
Mid Externalities, No CO_2 Internal Cost	$ 41,167	182,485	-	-	-	-	-	14	-	-	-	197,733
High Externalities, No CO_2 Internal Cost	$ 44,566	182,485	-	-	-	-	-	14	-	-	-	197,733
High Externalities, Use CO_2 Internal Cost	$ 40,328	160,600	-	-	2	-	-	10	-	-	1	246,072
Low Externalities, No CO_2 Internal Cost	$ 37,704	189,687	-	-	-	-	-	10	-	-	2	189,587
Low Externalities, Use CO_2 Internal Cost	$ 36,659	184,115	-	-	-	-	-	10	-	-	2	188,390
No Externalities, Use CO_2 Internal Cost	$ 35,554	195,433	-	-	-	-	-	7	-	-	3	178,327
No Externalities, No CO_2 Internal Cost	$ 35,554	195,433	-	-	-	-	-	7	-	-	3	178,327
Low Solar Price	$ 37,984	171,494	-	-	-	-	-	14	-	-	-	195,897
High Solar Price	$ 39,055	166,809	-	-	2	-	-	6	-	-	3	251,597
Low Wind Price	$ 38,219	149,020	-	-	4	-	-	6	-	-	2	304,514
High Wind Price	$ 38,621	174,459	-	-	-	-	-	12	-	-	1	194,137
Low Forecast	$ 37,558	165,508	-	-	-	-	-	11	-	-	-	214,277
High Forecast	$ 41,261	190,631	-	-	-	-	2	13	-	-	4	161,933
Low Coal Cost	$ 38,578	167,498	-	-	-	-	-	12	-	-	1	217,592
High Coal Cost	$ 38,663	167,498	-	-	-	-	-	12	-	-	1	217,592
Low Gas Price	$ 38,276	186,411	-	-	-	-	-	3	-	-	5	(41,214)
High Gas Price	$ 38,479	149,426	-	-	3	-	-	9	-	-	1	311,692
Low Nuke Cost	$ 38,128	167,498	-	-	-	-	-	12	-	-	1	217,592
High Nuke Cost	$ 39,113	167,498	-	-	-	-	-	12	-	-	1	217,592
High Market Price	$ 38,402	175,272	-	-	1	-	-	11	-	-	1	303,990
Low Market Price	$ 38,515	165,249	-	-	-	-	-	10	-	-	2	94,551
Low Market Capacity	$ 38,727	188,967	-	-	-	-	-	7	-	-	3	92,029
No Market	$ 39,086	189,334	-	-	-	-	-	5	-	-	4	-

Select Strategist Outputs--High Energy Efficiency

Scenario 213 KINN_SHEE_MONE_P RAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,615	178,162	-	-	-	-	-	11	-	-	-	193,900
Mid Externalities, No CO_2 Internal Cost	$ 41,632	204,746	-	-	-	-	-	11	-	-	-	190,042
High Externalities, No CO_2 Internal Cost	$ 45,459	204,746	-	-	-	-	-	11	-	-	-	190,042
High Externalities, Use CO_2 Internal Cost	$ 40,423	167,239	-	-	2	-	-	9	-	-	-	231,511
Low Externalities, No CO_2 Internal Cost	$ 37,783	206,656	-	-	-	-	-	11	-	-	-	188,307
Low Externalities, Use CO_2 Internal Cost	$ 36,530	202,594	-	-	-	-	-	6	-	-	2	172,986
No Externalities, Use CO_2 Internal Cost	$ 35,358	214,931	-	-	-	-	-	6	-	-	2	179,962
No Externalities, No CO_2 Internal Cost	$ 35,358	214,931	-	-	-	-	-	6	-	-	2	179,962
Low Solar Price	$ 38,048	181,438	-	-	-	-	-	11	-	-	-	178,486
High Solar Price	$ 39,016	176,715	-	-	1	-	-	3	-	-	3	228,687
Low Wind Price	$ 38,213	157,957	-	-	4	-	-	5	-	-	1	285,014
High Wind Price	$ 38,620	183,294	-	-	-	-	-	11	-	-	-	176,795
Low Forecast	$ 37,577	169,015	-	-	1	-	-	7	-	-	-	223,798
High Forecast	$ 41,287	195,087	-	-	-	-	3	9	-	-	4	160,971
Low Coal Cost	$ 38,549	178,162	-	-	-	-	-	11	-	-	-	193,900
High Coal Cost	$ 38,680	178,162	-	-	-	-	-	11	-	-	-	193,900
Low Gas Price	$ 38,120	189,305	-	-	-	-	-	2	-	-	4	(53,984)
High Gas Price	$ 38,580	158,544	-	-	3	-	-	8	-	-	-	293,486
Low Nuke Cost	$ 38,177	178,162	-	-	-	-	-	11	-	-	-	193,900
High Nuke Cost	$ 39,052	178,162	-	-	-	-	-	11	-	-	-	193,900
High Market Price	$ 38,443	186,068	-	-	1	-	-	10	-	-	-	291,584
Low Market Price	$ 38,465	174,199	-	-	-	-	-	9	-	-	1	66,366
Low Market Capacity	$ 38,633	185,042	-	-	-	-	-	6	-	-	2	105,857
No Market	$ 38,905	197,506	-	-	-	-	-	4	-	-	3	-

Select Strategist Outputs--High Energy Efficiency

Scenario 214 KINN_SHEE_MONX_PRAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,911	167,762	-	-	-	-	-	7	-	-	-	231,014
Mid Externalities, No CO_2 Internal Cost	$ 42,029	192,533	-	-	-	-	-	7	-	-	-	229,302
High Externalities, No CO_2 Internal Cost	$ 45,804	192,533	-	-	-	-	-	7	-	-	-	229,302
High Externalities, Use CO_2 Internal Cost	$ 40,602	158,662	-	-	1	-	-	6	-	-	-	266,769
Low Externalities, No CO_2 Internal Cost	$ 38,238	195,612	-	-	-	-	-	7	-	-	-	224,670
Low Externalities, Use CO_2 Internal Cost	$ 36,983	186,885	-	-	-	-	-	4	-	-	1	217,540
No Externalities, Use CO_2 Internal Cost	$ 35,884	201,996	-	-	-	-	-	4	-	-	1	217,977
No Externalities, No CO_2 Internal Cost	$ 35,884	201,996	-	-	-	-	-	4	-	-	1	217,977
Low Solar Price	$ 38,461	170,182	-	-	-	-	-	7	-	-	-	219,552
High Solar Price	$ 39,241	165,628	-	-	1	-	-	1	-	-	2	267,630
Low Wind Price	$ 38,583	153,013	-	-	3	-	-	4	-	-	-	304,709
High Wind Price	$ 38,916	171,516	-	-	-	-	-	7	-	-	-	218,175
Low Forecast	$ 37,906	161,917	-	-	-	-	-	4	-	-	-	249,239
High Forecast	$ 41,425	184,522	-	-	-	-	-	10	-	-	3	194,097
Low Coal Cost	$ 38,845	167,762	-	-	-	-	-	7	-	-	-	231,014
High Coal Cost	$ 38,976	167,762	-	-	-	-	-	7	-	-	-	231,014
Low Gas Price	$ 38,763	167,746	-	-	-	-	-	2	-	-	2	7,878
High Gas Price	$ 38,703	151,950	-	-	3	-	-	4	-	-	-	319,863
Low Nuke Cost	$ 38,303	167,762	-	-	-	-	-	7	-	-	-	231,014
High Nuke Cost	$ 39,518	167,762	-	-	-	-	-	7	-	-	-	231,014
High Market Price	$ 38,659	175,847	-	-	-	-	-	7	-	-	-	324,893
Low Market Price	$ 38,862	156,219	-	-	-	-	-	7	-	-	-	124,069
Low Market Capacity	$ 39,003	174,760	-	-	-	-	-	4	-	-	1	129,333
No Market	$ 39,357	178,097	-	-	-	-	-	2	-	-	2	-

Select Strategist Outputs--High Energy Efficiency

Scenario 215 KINN_SHEE_MONN_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,580	188,514	-	-	-	-	-	11	-	-	-	157,754
Mid Externalities, No CO_2 Internal Cost	$ 41,484	216,173	-	-	-	-	-	11	-	-	-	156,692
High Externalities, No CO_2 Internal Cost	$ 45,361	216,173	-	-	-	-	-	11	-	-	-	156,692
High Externalities, Use CO_2 Internal Cost	$ 40,508	177,348	-	-	2	-	-	9	-	-	-	194,659
Low Externalities, No CO_2 Internal Cost	$ 37,584	218,082	-	-	-	-	-	11	-	-	-	154,957
Low Externalities, Use CO_2 Internal Cost	$ 36,365	214,551	-	-	-	-	-	9	-	-	1	138,168
No Externalities, Use CO_2 Internal Cost	$ 35,126	229,380	-	-	-	-	-	6	-	-	2	142,085
No Externalities, No CO_2 Internal Cost	$ 35,126	229,380	-	-	-	-	-	6	-	-	2	142,085
Low Solar Price	$ 37,920	191,790	-	-	-	-	-	11	-	-	-	142,340
High Solar Price	$ 39,066	187,829	-	-	2	-	-	5	-	-	2	192,360
Low Wind Price	$ 38,155	165,286	-	-	4	-	-	7	-	-	-	258,755
High Wind Price	$ 38,585	193,646	-	-	-	-	-	11	-	-	-	140,649
Low Forecast	$ 37,518	181,040	-	-	-	-	-	9	-	-	-	178,129
High Forecast	$ 41,441	209,426	-	-	-	-	4	8	-	1	3	122,133
Low Coal Cost	$ 38,514	188,514	-	-	-	-	-	11	-	-	-	157,754
High Coal Cost	$ 38,646	188,514	-	-	-	-	-	11	-	-	-	157,754
Low Gas Price	$ 37,833	203,660	-	-	-	-	-	4	-	-	3	(94,842)
High Gas Price	$ 38,677	164,485	-	-	4	-	-	7	-	-	-	273,211
Low Nuke Cost	$ 38,281	188,514	-	-	-	-	-	11	-	-	-	157,754
High Nuke Cost	$ 38,880	188,514	-	-	-	-	-	11	-	-	-	157,754
High Market Price	$ 38,496	195,756	-	-	1	-	-	10	-	-	-	261,394
Low Market Price	$ 38,341	184,283	-	-	-	-	-	11	-	-	-	33,260
Low Market Capacity	$ 38,579	196,046	-	-	-	-	-	9	-	-	1	80,403
No Market	$ 38,764	209,659	-	-	-	-	-	6	-	-	2	-

Select Strategist Outputs--High Energy Efficiency

Scenario 216 KINN_SHEE_MONN_PRAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,533	164,326	-	-	-	-	-	4	-	-	-	244,956
Mid Externalities, No CO_2 Internal Cost	$ 41,737	188,724	-	-	-	-	-	4	-	-	-	249,037
High Externalities, No CO_2 Internal Cost	$ 45,577	188,724	-	-	-	-	-	4	-	-	-	249,037
High Externalities, Use CO_2 Internal Cost	$ 40,235	157,504	-	-	1	-	-	3	-	-	-	272,670
Low Externalities, No CO_2 Internal Cost	$ 37,893	190,417	-	-	-	-	-	4	-	-	-	243,719
Low Externalities, Use CO_2 Internal Cost	$ 36,616	177,947	-	-	-	-	-	4	-	-	-	237,923
No Externalities, Use CO_2 Internal Cost	$ 35,538	190,417	-	-	-	-	-	4	-	-	-	243,719
No Externalities, No CO_2 Internal Cost	$ 35,538	190,417	-	-	-	-	-	4	-	-	-	243,719
Low Solar Price	$ 38,180	165,547	-	-	-	-	-	4	-	-	-	238,667
High Solar Price	$ 38,841	162,802	-	-	1	-	-	3	-	-	-	276,514
Low Wind Price	$ 38,214	145,609	-	-	3	-	-	1	-	-	-	322,403
High Wind Price	$ 38,539	167,233	-	-	-	-	-	4	-	-	-	233,305
Low Forecast	$ 37,582	161,642	-	-	-	-	-	2	-	-	-	256,221
High Forecast	$ 41,074	179,745	-	-	-	-	-	11	-	-	1	199,700
Low Coal Cost	$ 38,467	164,326	-	-	-	-	-	4	-	-	-	244,956
High Coal Cost	$ 38,599	164,326	-	-	-	-	-	4	-	-	-	244,956
Low Gas Price	$ 38,532	161,721	-	-	-	-	-	-	-	-	2	9,489
High Gas Price	$ 38,297	149,100	-	-	3	-	-	1	-	-	-	328,877
Low Nuke Cost	$ 37,902	164,326	-	-	-	-	-	4	-	-	-	244,956
High Nuke Cost	$ 39,164	164,326	-	-	-	-	-	4	-	-	-	244,956
High Market Price	$ 38,269	175,587	-	-	1	-	-	3	-	-	-	332,045
Low Market Price	$ 38,506	149,605	-	-	-	-	-	4	-	-	-	137,794
Low Market Capacity	$ 38,582	165,531	-	-	-	-	-	4	-	-	-	144,936
No Market	$ 38,904	166,573	-	-	-	-	-	2	-	-	1	-

Select Strategist Outputs--High Energy Efficiency

Scenario 217 KINN_SHEN_MONE_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,628	198,087	-	-	-	-	2	5	-	-	-	175,631
Mid Externalities, No CO_2 Internal Cost	$ 41,962	244,003	-	-	-	-	2	5	-	-	-	142,596
High Externalities, No CO_2 Internal Cost	$ 46,337	227,054	-	-	-	-	2	5	-	-	-	195,769
High Externalities, Use CO_2 Internal Cost	$ 40,685	187,560	-	-	2	-	2	4	-	-	-	206,226
Low Externalities, No CO_2 Internal Cost	$ 37,574	244,003	-	-	-	-	2	5	-	-	-	142,596
Low Externalities, Use CO_2 Internal Cost	$ 36,159	230,950	-	-	-	-	2	5	-	-	-	133,422
No Externalities, Use CO_2 Internal Cost	$ 34,859	244,003	-	-	-	-	2	5	-	-	-	142,596
No Externalities, No CO_2 Internal Cost	$ 34,859	244,003	-	-	-	-	2	5	-	-	-	142,596
Low Solar Price	$ 38,097	198,087	-	-	-	-	2	5	-	-	-	175,631
High Solar Price	$ 39,074	203,173	-	-	2	-	-	3	-	1	-	182,908
Low Wind Price	$ 38,141	175,233	-	1	4	-	1	2	-	-	-	256,270
High Wind Price	$ 38,633	214,315	-	-	-	-	2	5	-	-	-	121,437
Low Forecast	$ 37,546	194,943	-	-	-	-	-	5	-	-	-	186,354
High Forecast	$ 41,539	228,910	-	-	-	-	3	7	-	3	-	106,055
Low Coal Cost	$ 38,554	198,087	-	-	-	-	2	5	-	-	-	175,631
High Coal Cost	$ 38,702	198,087	-	-	-	-	2	5	-	-	-	175,631
Low Gas Price	$ 37,724	221,398	-	-	-	-	-	3	-	1	1	(116,025)
High Gas Price	$ 38,834	183,184	-	-	3	-	2	3	-	-	-	259,282
Low Nuke Cost	$ 38,389	198,087	-	-	-	-	2	5	-	-	-	175,631
High Nuke Cost	$ 38,867	198,087	-	-	-	-	2	5	-	-	-	175,631
High Market Price	$ 38,569	214,272	-	-	-	-	2	5	-	-	-	251,101
Low Market Price	$ 38,326	200,328	-	-	-	-	2	5	-	-	-	14,582
Low Market Capacity	$ 38,560	208,739	-	-	-	-	2	5	-	-	-	76,672
No Market	$ 38,702	221,771	-	-	-	-	2	3	-	-	1	-

Select Strategist Outputs--High Energy Efficiency

Scenario 218 KINN_SHEN_MONX_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 39,012	189,412	-	-	-	-	-	3	-	-	-	209,810
Mid Externalities, No CO_2 Internal Cost	$ 42,512	234,000	-	-	-	-	-	3	-	-	-	174,887
High Externalities, No CO_2 Internal Cost	$ 46,867	196,982	-	-	3	-	-	1	-	-	-	289,233
High Externalities, Use CO_2 Internal Cost	$ 40,990	181,119	-	-	1	-	-	2	-	-	-	230,531
Low Externalities, No CO_2 Internal Cost	$ 38,110	234,000	-	-	-	-	-	3	-	-	-	174,887
Low Externalities, Use CO_2 Internal Cost	$ 36,647	220,747	-	-	-	-	-	3	-	-	-	165,997
No Externalities, Use CO_2 Internal Cost	$ 35,386	234,000	-	-	-	-	-	3	-	-	-	174,887
No Externalities, No CO_2 Internal Cost	$ 35,386	234,000	-	-	-	-	-	3	-	-	-	174,887
Low Solar Price	$ 38,671	189,412	-	-	-	-	-	3	-	-	-	209,810
High Solar Price	$ 39,304	187,763	-	-	2	-	-	1	-	-	-	225,760
Low Wind Price	$ 38,603	175,159	-	-	4	-	-	-	-	-	-	261,618
High Wind Price	$ 39,041	204,119	-	-	-	-	-	3	-	-	-	154,522
Low Forecast	$ 37,995	183,094	-	-	-	-	-	1	-	-	-	227,243
High Forecast	$ 41,732	208,106	-	-	-	-	4	6	-	1	-	155,834
Low Coal Cost	$ 38,938	189,412	-	-	-	-	-	3	-	-	-	209,810
High Coal Cost	$ 39,086	189,412	-	-	-	-	-	3	-	-	-	209,810
Low Gas Price	$ 38,385	199,858	-	-	-	-	-	1	-	-	1	(69,218)
High Gas Price	$ 39,115	175,508	-	-	3	-	-	1	-	-	-	282,069
Low Nuke Cost	$ 38,593	189,412	-	-	-	-	-	3	-	-	-	209,810
High Nuke Cost	$ 39,431	189,412	-	-	-	-	-	3	-	-	-	209,810
High Market Price	$ 38,884	205,992	-	-	-	-	-	3	-	-	-	282,659
Low Market Price	$ 38,798	187,231	-	-	-	-	-	3	-	-	-	46,182
Low Market Capacity	$ 38,913	200,237	-	-	-	-	-	3	-	-	-	100,162
No Market	$ 39,029	202,027	-	-	-	-	-	3	-	-	-	-

Select Strategist Outputs--High Energy Efficiency

Scenario 219 KINN_SHEN_MONE_PRAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,601	176,699	-	-	-	-	-	-	-	-	-	248,089
Mid Externalities, No CO_2 Internal Cost	$ 42,219	204,555	-	-	-	-	-	-	-	-	-	263,292
High Externalities, No CO_2 Internal Cost	$ 46,470	204,555	-	-	-	-	-	-	-	-	-	263,292
High Externalities, Use CO_2 Internal Cost	$ 40,463	172,840	-	-	-	-	-	-	-	-	-	250,655
Low Externalities, No CO_2 Internal Cost	$ 37,944	215,290	-	-	-	-	-	-	-	-	-	230,249
Low Externalities, Use CO_2 Internal Cost	$ 36,436	202,304	-	-	-	-	-	-	-	-	-	222,937
No Externalities, Use CO_2 Internal Cost	$ 35,261	215,290	-	-	-	-	-	-	-	-	-	230,249
No Externalities, No CO_2 Internal Cost	$ 35,261	215,290	-	-	-	-	-	-	-	-	-	230,249
Low Solar Price	$ 38,334	176,699	-	-	-	-	-	-	-	-	-	248,089
High Solar Price	$ 38,847	178,570	-	-	-	-	-	-	-	-	-	259,061
Low Wind Price	$ 38,400	168,866	-	-	-	-	-	-	-	-	-	283,729
High Wind Price	$ 38,658	186,731	-	-	-	-	-	-	-	-	-	213,381
Low Forecast	$ 37,649	174,614	-	-	-	-	-	-	-	-	-	248,934
High Forecast	$ 41,164	190,450	-	-	-	-	3	7	-	-	-	197,144
Low Coal Cost	$ 38,527	176,699	-	-	-	-	-	-	-	-	-	248,089
High Coal Cost	$ 38,675	176,699	-	-	-	-	-	-	-	-	-	248,089
Low Gas Price	$ 38,422	173,542	-	-	-	-	-	-	-	-	-	(758)
High Gas Price	$ 38,598	173,750	-	-	-	-	-	-	-	-	-	295,363
Low Nuke Cost	$ 38,025	176,699	-	-	-	-	-	-	-	-	-	248,089
High Nuke Cost	$ 39,176	176,699	-	-	-	-	-	-	-	-	-	248,089
High Market Price	$ 38,376	192,501	-	-	-	-	-	-	-	-	-	319,392
Low Market Price	$ 38,547	167,139	-	-	-	-	-	-	-	-	-	107,311
Low Market Capacity	$ 38,560	181,793	-	-	-	-	-	-	-	-	-	138,565
No Market	$ 38,770	178,746	-	-	-	-	-	-	-	-	-	-

Select Strategist Outputs--High Energy Efficiency

Scenario 220 KINN_SHEN_MONX_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,991	167,863	-	-	-	-	-	-	-	-	-	277,401
Mid Externalities, No CO_2 Internal Cost	$ 42,638	195,227	-	-	-	-	-	-	-	-	-	283,690
High Externalities, No CO_2 Internal Cost	$ 46,791	193,273	-	-	-	-	-	-	-	-	-	290,406
High Externalities, Use CO_2 Internal Cost	$ 40,717	161,898	-	-	-	-	-	-	-	-	-	293,119
Low Externalities, No CO_2 Internal Cost	$ 38,472	196,920	-	-	-	-	-	-	-	-	-	278,371
Low Externalities, Use CO_2 Internal Cost	$ 36,970	184,384	-	-	-	-	-	-	-	-	-	272,444
No Externalities, Use CO_2 Internal Cost	$ 35,886	196,920	-	-	-	-	-	-	-	-	-	278,371
No Externalities, No CO_2 Internal Cost	$ 35,886	196,920	-	-	-	-	-	-	-	-	-	278,371
Low Solar Price	$ 38,757	167,156	-	-	-	-	-	-	-	-	-	277,920
High Solar Price	$ 39,181	166,792	-	-	-	-	-	-	-	-	-	294,866
Low Wind Price	$ 38,782	158,048	-	-	-	-	-	-	-	-	-	324,009
High Wind Price	$ 38,998	170,770	-	-	-	-	-	-	-	-	-	265,750
Low Forecast	$ 38,078	162,828	-	-	-	-	-	-	-	-	-	292,644
High Forecast	$ 41,351	181,745	-	-	-	-	-	6	-	-	-	231,759
Low Coal Cost	$ 38,917	167,863	-	-	-	-	-	-	-	-	-	277,401
High Coal Cost	$ 39,065	167,863	-	-	-	-	-	-	-	-	-	277,401
Low Gas Price	$ 39,188	152,497	-	-	-	-	-	-	-	-	-	75,409
High Gas Price	$ 38,718	161,756	-	-	-	-	-	-	-	-	-	334,967
Low Nuke Cost	$ 38,252	167,863	-	-	-	-	-	-	-	-	-	277,401
High Nuke Cost	$ 39,730	167,863	-	-	-	-	-	-	-	-	-	277,401
High Market Price	$ 38,675	179,643	-	-	-	-	-	-	-	-	-	354,056
Low Market Price	$ 39,013	150,995	-	-	-	-	-	-	-	-	-	170,553
Low Market Capacity	$ 39,044	166,234	-	-	-	-	-	-	-	-	-	167,185
No Market	$ 39,451	163,397	-	-	-	-	-	-	-	-	-	-

Select Strategist Outputs--High Energy Efficiency

Scenario 221 KINN_SHEE_MONE_P RAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,471	192,555	-	-	-	-	2	9	-	-	-	144,687
Mid Externalities, No CO_2 Internal Cost	$ 41,324	220,522	-	-	-	-	2	9	-	-	-	144,128
High Externalities, No CO_2 Internal Cost	$ 45,213	220,522	-	-	-	-	2	9	-	-	-	144,128
High Externalities, Use CO_2 Internal Cost	$ 40,442	181,213	-	-	2	-	2	7	-	-	-	181,714
Low Externalities, No CO_2 Internal Cost	$ 37,414	222,432	-	-	-	-	2	9	-	-	-	142,394
Low Externalities, Use CO_2 Internal Cost	$ 36,210	221,646	-	-	-	-	-	9	-	1	-	120,014
No Externalities, Use CO_2 Internal Cost	$ 34,936	236,382	-	-	-	-	-	6	-	1	1	124,444
No Externalities, No CO_2 Internal Cost	$ 34,936	236,382	-	-	-	-	-	6	-	1	1	124,444
Low Solar Price	$ 37,769	195,831	-	-	-	-	2	9	-	-	-	129,273
High Solar Price	$ 38,983	193,612	-	-	2	-	-	5	-	1	1	177,563
Low Wind Price	$ 38,017	165,746	-	1	3	-	1	6	-	-	-	257,311
High Wind Price	$ 38,477	197,687	-	-	-	-	2	9	-	-	-	127,582
Low Forecast	$ 37,355	187,031	-	-	-	-	-	9	-	-	-	159,066
High Forecast	$ 41,413	218,136	-	-	-	-	3	9	-	3	1	101,578
Low Coal Cost	$ 38,406	192,555	-	-	-	-	2	9	-	-	-	144,687
High Coal Cost	$ 38,537	192,555	-	-	-	-	2	9	-	-	-	144,687
Low Gas Price	$ 37,607	211,630	-	-	-	-	-	4	-	1	2	(114,741)
High Gas Price	$ 38,622	168,580	-	-	4	-	2	5	-	-	-	260,333
Low Nuke Cost	$ 38,233	192,555	-	-	-	-	2	9	-	-	-	144,687
High Nuke Cost	$ 38,710	192,555	-	-	-	-	2	9	-	-	-	144,687
High Market Price	$ 38,417	199,709	-	-	1	-	2	8	-	-	-	249,649
Low Market Price	$ 38,201	188,896	-	-	-	-	2	9	-	-	-	19,560
Low Market Capacity	$ 38,462	200,100	-	-	-	-	2	7	-	-	1	71,626
No Market	$ 38,628	213,738	-	-	-	-	2	4	-	-	2	-

Select Strategist Outputs--High Energy Efficiency

Scenario 222 KINN_SHEE_MONE_PRAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,416	168,788	-	-	-	-	-	4	-	-	-	229,478
Mid Externalities, No CO_2 Internal Cost	$ 41,606	194,155	-	-	-	-	-	4	-	-	-	234,744
High Externalities, No CO_2 Internal Cost	$ 45,503	194,155	-	-	-	-	-	4	-	-	-	234,744
High Externalities, Use CO_2 Internal Cost	$ 40,183	161,837	-	-	1	-	-	3	-	-	-	257,323
Low Externalities, No CO_2 Internal Cost	$ 37,704	195,848	-	-	-	-	-	4	-	-	-	229,426
Low Externalities, Use CO_2 Internal Cost	$ 36,427	183,057	-	-	-	-	-	4	-	-	-	223,005
No Externalities, Use CO_2 Internal Cost	$ 35,315	195,848	-	-	-	-	-	4	-	-	-	229,426
No Externalities, No CO_2 Internal Cost	$ 35,315	195,848	-	-	-	-	-	4	-	-	-	229,426
Low Solar Price	$ 38,063	170,008	-	-	-	-	-	4	-	-	-	223,189
High Solar Price	$ 38,724	167,263	-	-	1	-	-	3	-	-	-	261,036
Low Wind Price	$ 38,096	150,070	-	-	3	-	-	1	-	-	-	306,925
High Wind Price	$ 38,422	171,694	-	-	-	-	-	4	-	-	-	217,826
Low Forecast	$ 37,462	165,977	-	-	-	-	-	2	-	-	-	241,424
High Forecast	$ 41,050	181,290	-	-	-	-	3	8	-	-	1	191,535
Low Coal Cost	$ 38,350	168,788	-	-	-	-	-	4	-	-	-	229,478
High Coal Cost	$ 38,481	168,788	-	-	-	-	-	4	-	-	-	229,478
Low Gas Price	$ 38,286	166,882	-	-	-	-	-	-	-	-	2	(10,363)
High Gas Price	$ 38,258	153,725	-	-	3	-	-	1	-	-	-	313,776
Low Nuke Cost	$ 37,840	168,788	-	-	-	-	-	4	-	-	-	229,478
High Nuke Cost	$ 38,991	168,788	-	-	-	-	-	4	-	-	-	229,478
High Market Price	$ 38,190	180,556	-	-	1	-	-	3	-	-	-	319,251
Low Market Price	$ 38,347	154,143	-	-	-	-	-	4	-	-	-	119,288
Low Market Capacity	$ 38,402	169,580	-	-	-	-	-	4	-	-	-	136,838
No Market	$ 38,642	170,089	-	-	-	-	-	2	-	-	1	-

Select Strategist Outputs--High Energy Efficiency

Scenario 223 KINN_SHEE_MONX_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,807	182,938	-	-	-	-	-	7	-	-	-	176,427
Mid Externalities, No CO_2 Internal Cost	$ 41,817	210,291	-	-	-	-	-	7	-	-	-	179,006
High Externalities, No CO_2 Internal Cost	$ 45,728	210,291	-	-	-	-	-	7	-	-	-	179,006
High Externalities, Use CO_2 Internal Cost	$ 40,695	170,827	-	-	2	-	-	5	-	-	-	222,689
Low Externalities, No CO_2 Internal Cost	$ 37,890	211,665	-	-	-	-	-	7	-	-	-	177,645
Low Externalities, Use CO_2 Internal Cost	$ 36,661	201,280	-	-	-	-	-	7	-	-	-	166,578
No Externalities, Use CO_2 Internal Cost	$ 35,462	221,517	-	-	-	-	-	4	-	-	1	165,752
No Externalities, No CO_2 Internal Cost	$ 35,462	221,517	-	-	-	-	-	4	-	-	1	165,752
Low Solar Price	$ 38,298	185,358	-	-	-	-	-	7	-	-	-	164,965
High Solar Price	$ 39,205	180,761	-	-	2	-	-	3	-	-	1	214,819
Low Wind Price	$ 38,416	163,973	-	-	3	-	-	4	-	-	-	264,129
High Wind Price	$ 38,813	186,692	-	-	-	-	-	7	-	-	-	163,588
Low Forecast	$ 37,786	176,769	-	-	-	-	-	5	-	-	-	195,031
High Forecast	$ 41,626	199,382	-	-	-	-	4	6	-	1	2	148,470
Low Coal Cost	$ 38,742	182,938	-	-	-	-	-	7	-	-	-	176,427
High Coal Cost	$ 38,873	182,938	-	-	-	-	-	7	-	-	-	176,427
Low Gas Price	$ 38,252	194,107	-	-	-	-	-	-	-	-	3	(80,734)
High Gas Price	$ 38,818	164,748	-	-	3	-	-	4	-	-	-	276,844
Low Nuke Cost	$ 38,388	182,938	-	-	-	-	-	7	-	-	-	176,427
High Nuke Cost	$ 39,226	182,938	-	-	-	-	-	7	-	-	-	176,427
High Market Price	$ 38,685	191,505	-	-	1	-	-	6	-	-	-	280,113
Low Market Price	$ 38,617	172,784	-	-	-	-	-	7	-	-	-	62,410
Low Market Capacity	$ 38,786	185,736	-	-	-	-	-	7	-	-	-	100,060
No Market	$ 38,924	193,859	-	-	-	-	-	4	-	-	1	-

Select Strategist Outputs--High Energy Efficiency

Scenario 224 KINN_SHEE_MONX_PRAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,794	160,234	-	-	-	-	-	-	-	-	-	266,829
Mid Externalities, No CO_2 Internal Cost	$ 42,068	184,301	-	-	-	-	-	-	-	-	-	270,318
High Externalities, No CO_2 Internal Cost	$ 45,897	182,348	-	-	-	-	-	-	-	-	-	277,035
High Externalities, Use CO_2 Internal Cost	$ 40,453	155,190	-	-	-	-	-	-	-	-	-	283,938
Low Externalities, No CO_2 Internal Cost	$ 38,227	185,994	-	-	-	-	-	-	-	-	-	265,000
Low Externalities, Use CO_2 Internal Cost	$ 36,926	173,577	-	-	-	-	-	-	-	-	-	259,586
No Externalities, Use CO_2 Internal Cost	$ 35,873	185,994	-	-	-	-	-	-	-	-	-	265,000
No Externalities, No CO_2 Internal Cost	$ 35,873	185,994	-	-	-	-	-	-	-	-	-	265,000
Low Solar Price	$ 38,560	159,526	-	-	-	-	-	-	-	-	-	267,348
High Solar Price	$ 38,985	159,162	-	-	-	-	-	-	-	-	-	284,294
Low Wind Price	$ 38,585	150,419	-	-	-	-	-	-	-	-	-	313,436
High Wind Price	$ 38,801	163,140	-	-	-	-	-	-	-	-	-	255,178
Low Forecast	$ 37,871	155,835	-	-	-	-	-	-	-	-	-	283,334
High Forecast	$ 41,216	171,256	-	-	-	-	-	9	-	-	-	227,386
Low Coal Cost	$ 38,729	160,234	-	-	-	-	-	-	-	-	-	266,829
High Coal Cost	$ 38,860	160,234	-	-	-	-	-	-	-	-	-	266,829
Low Gas Price	$ 38,954	145,546	-	-	-	-	-	-	-	-	-	65,540
High Gas Price	$ 38,522	152,459	-	-	-	-	-	-	-	-	-	323,329
Low Nuke Cost	$ 38,055	160,234	-	-	-	-	-	-	-	-	-	266,829
High Nuke Cost	$ 39,534	160,234	-	-	-	-	-	-	-	-	-	266,829
High Market Price	$ 38,493	172,089	-	-	-	-	-	-	-	-	-	343,938
Low Market Price	$ 38,804	143,532	-	-	-	-	-	-	-	-	-	160,124
Low Market Capacity	$ 38,827	159,188	-	-	-	-	-	-	-	-	-	162,234
No Market	$ 39,208	155,686	-	-	-	-	-	-	-	-	-	-

Select Strategist Outputs--High Energy Efficiency

Scenario 225 KINE_SHEN_MONE_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,500	194,997	-	-	-	-	4	7	-	-	-	159,697
Mid Externalities, No CO_2 Internal Cost	$ 41,281	222,706	-	-	-	-	4	7	-	-	-	139,043
High Externalities, No CO_2 Internal Cost	$ 45,215	212,249	-	-	-	-	4	7	-	-	-	168,191
High Externalities, Use CO_2 Internal Cost	$ 40,516	185,484	-	-	1	-	4	6	-	-	-	191,431
Low Externalities, No CO_2 Internal Cost	$ 37,328	222,706	-	-	-	-	4	7	-	-	-	139,043
Low Externalities, Use CO_2 Internal Cost	$ 36,135	216,042	-	-	-	-	4	7	-	-	-	135,470
No Externalities, Use CO_2 Internal Cost	$ 34,849	231,843	-	-	-	-	2	6	-	1	-	123,076
No Externalities, No CO_2 Internal Cost	$ 34,849	231,843	-	-	-	-	2	6	-	1	-	123,076
Low Solar Price	$ 37,828	194,997	-	-	-	-	4	7	-	-	-	159,697
High Solar Price	$ 39,019	197,984	-	-	1	-	2	3	-	1	1	186,000
Low Wind Price	$ 38,046	167,408	-	2	3	-	3	3	-	-	-	267,822
High Wind Price	$ 38,504	205,270	-	-	-	-	4	7	-	-	-	130,512
Low Forecast	$ 37,379	188,451	-	-	-	-	2	7	-	-	-	174,924
High Forecast	$ 41,454	221,309	-	-	-	-	6	8	-	3	-	105,635
Low Coal Cost	$ 38,449	194,997	-	-	-	-	4	7	-	-	-	159,697
High Coal Cost	$ 38,551	194,997	-	-	-	-	4	7	-	-	-	159,697
Low Gas Price	$ 37,673	222,173	-	-	-	-	2	2	-	1	2	(120,268)
High Gas Price	$ 38,656	175,719	-	-	3	-	4	4	-	-	-	263,183
Low Nuke Cost	$ 38,261	194,997	-	-	-	-	4	7	-	-	-	159,697
High Nuke Cost	$ 38,739	194,997	-	-	-	-	4	7	-	-	-	159,697
High Market Price	$ 38,428	203,029	-	-	1	-	4	6	-	-	-	256,982
Low Market Price	$ 38,235	193,435	-	-	-	-	4	7	-	-	-	29,727
Low Market Capacity	$ 38,493	215,652	-	-	-	-	4	4	-	-	1	56,227
No Market	$ 38,647	215,736	-	-	-	-	2	4	-	1	1	-

Select Strategist Outputs--High Energy Efficiency

Scenario 226 KINE_SHEN_MONE_P RAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,411	172,371	-	-	-	-	-	4	-	-	-	237,885
Mid Externalities, No CO_2 Internal Cost	$ 41,472	189,663	-	-	-	-	-	4	-	-	-	237,733
High Externalities, No CO_2 Internal Cost	$ 45,343	189,663	-	-	-	-	-	4	-	-	-	237,733
High Externalities, Use CO_2 Internal Cost	$ 40,225	166,007	-	-	1	-	-	3	-	-	-	265,158
Low Externalities, No CO_2 Internal Cost	$ 37,596	191,356	-	-	-	-	-	4	-	-	-	232,414
Low Externalities, Use CO_2 Internal Cost	$ 36,315	185,164	-	-	-	-	-	4	-	-	-	229,897
No Externalities, Use CO_2 Internal Cost	$ 35,193	195,758	-	-	-	-	-	4	-	-	-	227,728
No Externalities, No CO_2 Internal Cost	$ 35,193	195,758	-	-	-	-	-	4	-	-	-	227,728
Low Solar Price	$ 38,026	173,591	-	-	-	-	-	4	-	-	-	231,596
High Solar Price	$ 38,736	171,909	-	-	1	-	-	3	-	-	-	268,732
Low Wind Price	$ 38,118	153,954	-	-	3	-	-	1	-	-	-	313,963
High Wind Price	$ 38,417	175,277	-	-	-	-	-	4	-	-	-	226,234
Low Forecast	$ 37,432	169,336	-	-	-	-	-	2	-	-	-	251,635
High Forecast	$ 41,097	185,332	-	-	-	-	6	5	-	-	1	199,814
Low Coal Cost	$ 38,359	172,371	-	-	-	-	-	4	-	-	-	237,885
High Coal Cost	$ 38,462	172,371	-	-	-	-	-	4	-	-	-	237,885
Low Gas Price	$ 38,324	171,528	-	-	-	-	-	2	-	-	1	6,512
High Gas Price	$ 38,263	161,810	-	-	2	-	-	2	-	-	-	312,347
Low Nuke Cost	$ 37,835	172,371	-	-	-	-	-	4	-	-	-	237,885
High Nuke Cost	$ 38,986	172,371	-	-	-	-	-	4	-	-	-	237,885
High Market Price	$ 38,172	183,651	-	-	-	-	-	4	-	-	-	321,229
Low Market Price	$ 38,360	158,925	-	-	-	-	-	4	-	-	-	131,434
Low Market Capacity	$ 38,430	174,380	-	-	-	-	-	4	-	-	-	141,019
No Market	$ 38,674	174,016	-	-	-	-	-	2	-	-	1	-

Select Strategist Outputs--High Energy Efficiency

Scenario 227 KINE_SHEN_MONX_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,844	182,080	-	-	-	-	1	5	-	-	-	217,058
Mid Externalities, No CO_2 Internal Cost	$ 41,796	212,970	-	-	-	-	1	5	-	-	-	173,370
High Externalities, No CO_2 Internal Cost	$ 45,780	212,970	-	-	-	-	1	5	-	-	-	173,370
High Externalities, Use CO_2 Internal Cost	$ 40,772	177,659	-	-	1	-	1	5	-	-	-	225,545
Low Externalities, No CO_2 Internal Cost	$ 37,811	212,970	-	-	-	-	1	5	-	-	-	173,370
Low Externalities, Use CO_2 Internal Cost	$ 36,561	206,466	-	-	-	-	1	5	-	-	-	170,000
No Externalities, Use CO_2 Internal Cost	$ 35,350	217,793	-	-	-	-	1	5	-	-	-	160,781
No Externalities, No CO_2 Internal Cost	$ 35,350	217,793	-	-	-	-	1	5	-	-	-	160,781
Low Solar Price	$ 38,407	182,080	-	-	-	-	1	5	-	-	-	217,058
High Solar Price	$ 39,227	184,891	-	-	1	-	1	2	-	-	1	225,730
Low Wind Price	$ 38,444	166,107	-	1	3	-	-	3	-	-	-	276,431
High Wind Price	$ 38,854	195,734	-	-	-	-	1	5	-	-	-	165,229
Low Forecast	$ 37,777	178,371	-	-	-	-	-	5	-	-	-	214,910
High Forecast	$ 41,658	203,746	-	-	-	-	6	6	-	1	1	153,995
Low Coal Cost	$ 38,793	182,080	-	-	-	-	1	5	-	-	-	217,058
High Coal Cost	$ 38,896	182,080	-	-	-	-	1	5	-	-	-	217,058
Low Gas Price	$ 38,312	196,914	-	-	-	-	1	1	-	-	2	(61,010)
High Gas Price	$ 38,867	173,389	-	-	2	-	1	4	-	-	-	275,966
Low Nuke Cost	$ 38,425	182,080	-	-	-	-	1	5	-	-	-	217,058
High Nuke Cost	$ 39,263	182,080	-	-	-	-	1	5	-	-	-	217,058
High Market Price	$ 38,692	196,555	-	-	-	-	1	5	-	-	-	285,426
Low Market Price	$ 38,657	181,197	-	-	-	-	1	5	-	-	-	62,938
Low Market Capacity	$ 38,794	193,406	-	-	-	-	1	5	-	-	-	101,840
No Market	$ 38,960	197,498	-	-	-	-	1	3	-	-	1	-

Select Strategist Outputs--High Energy Efficiency

Scenario 228 KINE_SHEN_MONX_PRAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,769	163,543	-	-	-	-	-	-	-	-	-	275,497
Mid Externalities, No CO_2 Internal Cost	$ 41,928	180,023	-	-	-	-	-	-	-	-	-	274,497
High Externalities, No CO_2 Internal Cost	$ 45,737	178,069	-	-	-	-	-	-	-	-	-	281,214
High Externalities, Use CO_2 Internal Cost	$ 40,474	158,840	-	-	-	-	-	-	-	-	-	293,835
Low Externalities, No CO_2 Internal Cost	$ 38,106	181,716	-	-	-	-	-	-	-	-	-	269,179
Low Externalities, Use CO_2 Internal Cost	$ 36,798	175,622	-	-	-	-	-	-	-	-	-	266,854
No Externalities, Use CO_2 Internal Cost	$ 35,740	181,716	-	-	-	-	-	-	-	-	-	269,179
No Externalities, No CO_2 Internal Cost	$ 35,740	181,716	-	-	-	-	-	-	-	-	-	269,179
Low Solar Price	$ 38,503	162,836	-	-	-	-	-	-	-	-	-	276,016
High Solar Price	$ 38,995	162,651	-	-	-	-	-	-	-	-	-	292,998
Low Wind Price	$ 38,601	157,756	-	-	-	-	-	-	-	-	-	316,676
High Wind Price	$ 38,776	166,450	-	-	-	-	-	-	-	-	-	263,846
Low Forecast	$ 37,836	159,188	-	-	-	-	-	-	-	-	-	290,613
High Forecast	$ 41,253	177,407	-	-	-	-	2	7	-	-	-	233,005
Low Coal Cost	$ 38,718	163,543	-	-	-	-	-	-	-	-	-	275,497
High Coal Cost	$ 38,820	163,543	-	-	-	-	-	-	-	-	-	275,497
Low Gas Price	$ 38,997	156,867	-	-	-	-	-	-	-	-	-	56,754
High Gas Price	$ 38,519	159,929	-	-	-	-	-	-	-	-	-	323,143
Low Nuke Cost	$ 38,030	163,543	-	-	-	-	-	-	-	-	-	275,497
High Nuke Cost	$ 39,508	163,543	-	-	-	-	-	-	-	-	-	275,497
High Market Price	$ 38,455	174,180	-	-	-	-	-	-	-	-	-	349,431
Low Market Price	$ 38,803	148,561	-	-	-	-	-	-	-	-	-	173,314
Low Market Capacity	$ 38,856	164,819	-	-	-	-	-	-	-	-	-	165,603
No Market	$ 39,268	161,771	-	-	-	-	-	-	-	-	-	-

Select Strategist Outputs--High Energy Efficiency

Scenario 229 KINE_SHEE_MONN_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,517	183,319	-	-	-	-	1	11	-	-	1	165,793
Mid Externalities, No CO_2 Internal Cost	$ 40,939	203,157	-	-	-	-	1	11	-	-	1	146,367
High Externalities, No CO_2 Internal Cost	$ 44,508	203,157	-	-	-	-	1	11	-	-	1	146,367
High Externalities, Use CO_2 Internal Cost	$ 40,416	174,888	-	-	2	-	1	9	-	-	1	198,825
Low Externalities, No CO_2 Internal Cost	$ 37,353	208,366	-	-	-	-	1	9	-	-	2	137,572
Low Externalities, Use CO_2 Internal Cost	$ 36,341	202,306	-	-	-	-	1	9	-	-	2	135,345
No Externalities, Use CO_2 Internal Cost	$ 35,139	212,198	-	-	-	-	1	9	-	-	2	129,063
No Externalities, No CO_2 Internal Cost	$ 35,139	212,198	-	-	-	-	1	9	-	-	2	129,063
Low Solar Price	$ 37,835	190,280	-	-	-	-	1	11	-	-	1	142,338
High Solar Price	$ 39,015	183,304	-	-	2	-	1	5	-	-	3	194,151
Low Wind Price	$ 38,064	161,451	-	1	3	-	-	6	-	-	2	264,417
High Wind Price	$ 38,517	190,280	-	-	-	-	1	11	-	-	1	142,338
Low Forecast	$ 37,454	185,028	-	-	-	-	-	10	-	-	1	158,467
High Forecast	$ 41,398	204,856	-	-	-	-	6	9	-	1	3	116,806
Low Coal Cost	$ 38,474	183,319	-	-	-	-	1	11	-	-	1	165,793
High Coal Cost	$ 38,560	183,319	-	-	-	-	1	11	-	-	1	165,793
Low Gas Price	$ 37,770	200,728	-	-	-	-	1	4	-	-	4	(85,358)
High Gas Price	$ 38,599	162,331	-	-	4	-	1	7	-	-	1	270,881
Low Nuke Cost	$ 38,217	183,319	-	-	-	-	1	11	-	-	1	165,793
High Nuke Cost	$ 38,816	183,319	-	-	-	-	1	11	-	-	1	165,793
High Market Price	$ 38,425	190,934	-	-	1	-	1	10	-	-	1	261,808
Low Market Price	$ 38,272	183,473	-	-	-	-	1	9	-	-	2	32,726
Low Market Capacity	$ 38,522	205,678	-	-	-	-	1	6	-	-	3	56,811
No Market	$ 38,716	206,184	-	-	-	-	1	4	-	-	4	-

Select Strategist Outputs--High Energy Efficiency

Scenario 230 KINE_SHEE_MONN_PRAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,380	157,943	-	-	-	-	-	7	-	-	-	249,049
Mid Externalities, No CO_2 Internal Cost	$ 41,059	169,907	-	-	-	-	-	7	-	-	-	244,500
High Externalities, No CO_2 Internal Cost	$ 44,507	169,907	-	-	-	-	-	7	-	-	-	244,500
High Externalities, Use CO_2 Internal Cost	$ 40,035	153,091	-	-	1	-	-	6	-	-	-	276,113
Low Externalities, No CO_2 Internal Cost	$ 37,607	171,600	-	-	-	-	-	7	-	-	-	239,182
Low Externalities, Use CO_2 Internal Cost	$ 36,535	166,169	-	-	-	-	-	7	-	-	-	237,975
No Externalities, Use CO_2 Internal Cost	$ 35,492	177,827	-	-	-	-	-	5	-	-	1	232,677
No Externalities, No CO_2 Internal Cost	$ 35,492	177,827	-	-	-	-	-	5	-	-	1	232,677
Low Solar Price	$ 37,937	159,164	-	-	-	-	-	7	-	-	-	242,761
High Solar Price	$ 38,754	159,723	-	-	2	-	-	1	-	-	2	279,200
Low Wind Price	$ 38,099	140,433	-	-	3	-	-	5	-	-	-	327,704
High Wind Price	$ 38,387	160,850	-	-	-	-	-	7	-	-	-	237,398
Low Forecast	$ 37,398	155,322	-	-	-	-	-	5	-	-	-	263,058
High Forecast	$ 41,011	175,879	-	-	-	-	2	10	-	-	2	200,201
Low Coal Cost	$ 38,337	157,943	-	-	-	-	-	7	-	-	-	249,049
High Coal Cost	$ 38,423	157,943	-	-	-	-	-	7	-	-	-	249,049
Low Gas Price	$ 38,444	159,490	-	-	-	-	-	1	-	-	3	17,496
High Gas Price	$ 38,098	146,794	-	-	2	-	-	5	-	-	-	322,768
Low Nuke Cost	$ 37,750	157,943	-	-	-	-	-	7	-	-	-	249,049
High Nuke Cost	$ 39,011	157,943	-	-	-	-	-	7	-	-	-	249,049
High Market Price	$ 38,106	168,290	-	-	-	-	-	7	-	-	-	328,561
Low Market Price	$ 38,377	145,253	-	-	-	-	-	7	-	-	-	147,872
Low Market Capacity	$ 38,494	162,336	-	-	-	-	-	5	-	-	1	145,296
No Market	$ 38,824	161,565	-	-	-	-	-	3	-	-	2	-

Select Strategist Outputs--High Energy Efficiency

Scenario 231 KINE_SHEE_MONE_PRAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,507	171,882	-	-	-	-	-	12	-	-	1	202,146
Mid Externalities, No CO_2 Internal Cost	$ 41,030	187,553	-	-	-	-	-	14	-	-	-	182,988
High Externalities, No CO_2 Internal Cost	$ 44,479	187,553	-	-	-	-	-	14	-	-	-	182,988
High Externalities, Use CO_2 Internal Cost	$ 40,279	164,912	-	-	2	-	-	10	-	-	1	230,817
Low Externalities, No CO_2 Internal Cost	$ 37,516	194,755	-	-	-	-	-	10	-	-	2	174,842
Low Externalities, Use CO_2 Internal Cost	$ 36,475	189,004	-	-	-	-	-	10	-	-	2	173,347
No Externalities, Use CO_2 Internal Cost	$ 35,337	200,500	-	-	-	-	-	7	-	-	3	163,579
No Externalities, No CO_2 Internal Cost	$ 35,337	200,500	-	-	-	-	-	7	-	-	3	163,579
Low Solar Price	$ 37,871	175,878	-	-	-	-	-	14	-	-	-	180,451
High Solar Price	$ 38,942	171,193	-	-	2	-	-	6	-	-	3	236,153
Low Wind Price	$ 38,105	153,404	-	-	4	-	-	6	-	-	2	289,071
High Wind Price	$ 38,508	178,843	-	-	-	-	-	12	-	-	1	178,692
Low Forecast	$ 37,441	169,785	-	-	-	-	-	11	-	-	-	199,358
High Forecast	$ 41,254	191,067	-	-	-	-	6	9	-	-	4	155,380
Low Coal Cost	$ 38,464	171,882	-	-	-	-	-	12	-	-	1	202,146
High Coal Cost	$ 38,550	171,882	-	-	-	-	-	12	-	-	1	202,146
Low Gas Price	$ 38,035	191,499	-	-	-	-	-	3	-	-	5	(60,981)
High Gas Price	$ 38,444	153,937	-	-	3	-	-	9	-	-	1	296,518
Low Nuke Cost	$ 38,070	171,882	-	-	-	-	-	12	-	-	1	202,146
High Nuke Cost	$ 38,945	171,882	-	-	-	-	-	12	-	-	1	202,146
High Market Price	$ 38,326	180,087	-	-	1	-	-	11	-	-	1	291,103
Low Market Price	$ 38,361	169,753	-	-	-	-	-	10	-	-	2	76,181
Low Market Capacity	$ 38,549	192,949	-	-	-	-	-	7	-	-	3	83,937
No Market	$ 38,829	192,756	-	-	-	-	-	5	-	-	4	-

Select Strategist Outputs--High Energy Efficiency

Scenario 232 KINE_SHEE_MONX_P RAN	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,767	164,555	-	-	-	-	-	8	-	-	1	230,932
Mid Externalities, No CO_2 Internal Cost	$ 41,378	175,517	-	-	-	-	-	10	-	-	-	222,003
High Externalities, No CO_2 Internal Cost	$ 44,785	175,517	-	-	-	-	-	10	-	-	-	222,003
High Externalities, Use CO_2 Internal Cost	$ 40,424	154,249	-	-	1	-	-	9	-	-	-	269,362
Low Externalities, No CO_2 Internal Cost	$ 37,949	180,856	-	-	-	-	-	8	-	-	1	216,694
Low Externalities, Use CO_2 Internal Cost	$ 36,881	178,288	-	-	-	-	-	5	-	-	2	211,109
No Externalities, Use CO_2 Internal Cost	$ 35,810	188,606	-	-	-	-	-	5	-	-	2	199,791
No Externalities, No CO_2 Internal Cost	$ 35,810	188,606	-	-	-	-	-	5	-	-	2	199,791
Low Solar Price	$ 38,250	164,759	-	-	-	-	-	10	-	-	-	219,929
High Solar Price	$ 39,126	163,760	-	-	-	-	-	5	-	-	2	258,841
Low Wind Price	$ 38,428	148,655	-	-	3	-	-	5	-	-	1	307,780
High Wind Price	$ 38,772	168,309	-	-	-	-	-	8	-	-	1	218,093
Low Forecast	$ 37,726	156,466	-	-	-	-	-	7	-	-	-	250,998
High Forecast	$ 41,362	181,954	-	-	-	-	2	9	-	-	4	191,147
Low Coal Cost	$ 38,724	164,555	-	-	-	-	-	8	-	-	1	230,932
High Coal Cost	$ 38,810	164,555	-	-	-	-	-	8	-	-	1	230,932
Low Gas Price	$ 38,642	170,020	-	-	-	-	-	1	-	-	4	(750)
High Gas Price	$ 38,517	144,880	-	-	2	-	-	8	-	-	-	323,231
Low Nuke Cost	$ 38,160	164,555	-	-	-	-	-	8	-	-	1	230,932
High Nuke Cost	$ 39,374	164,555	-	-	-	-	-	8	-	-	1	230,932
High Market Price	$ 38,514	169,019	-	-	-	-	-	10	-	-	-	322,156
Low Market Price	$ 38,725	153,764	-	-	-	-	-	8	-	-	1	127,393
Low Market Capacity	$ 38,873	170,804	-	-	-	-	-	5	-	-	2	128,814
No Market	$ 39,249	175,545	-	-	-	-	-	3	-	-	3	-

Select Strategist Outputs--High Energy Efficiency

Scenario 233 KINE_SHEE_MONE_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,403	185,738	-	-	-	-	4	8	-	-	1	154,830
Mid Externalities, No CO_2 Internal Cost	$ 40,755	202,388	-	-	-	-	4	10	-	-	-	138,213
High Externalities, No CO_2 Internal Cost	$ 44,252	202,388	-	-	-	-	4	10	-	-	-	138,213
High Externalities, Use CO_2 Internal Cost	$ 40,330	176,437	-	-	2	-	4	8	-	-	-	188,118
Low Externalities, No CO_2 Internal Cost	$ 37,177	214,578	-	-	-	-	2	8	-	1	1	120,937
Low Externalities, Use CO_2 Internal Cost	$ 36,183	208,541	-	-	-	-	2	8	-	1	1	118,355
No Externalities, Use CO_2 Internal Cost	$ 34,950	218,411	-	-	-	-	2	8	-	1	1	112,427
No Externalities, No CO_2 Internal Cost	$ 34,950	218,411	-	-	-	-	2	8	-	1	1	112,427
Low Solar Price	$ 37,610	189,345	-	-	-	-	4	10	-	-	-	133,470
High Solar Price	$ 38,935	189,010	-	-	2	-	2	4	-	1	2	177,992
Low Wind Price	$ 37,953	162,165	-	2	2	-	3	3	-	-	2	261,251
High Wind Price	$ 38,404	192,699	-	-	-	-	4	8	-	-	1	131,375
Low Forecast	$ 37,269	184,658	-	-	-	-	2	10	-	-	-	146,753
High Forecast	$ 41,346	208,476	-	-	-	-	8	7	-	2	2	105,952
Low Coal Cost	$ 38,361	185,738	-	-	-	-	4	8	-	-	1	154,830
High Coal Cost	$ 38,446	185,738	-	-	-	-	4	8	-	-	1	154,830
Low Gas Price	$ 37,554	208,125	-	-	-	-	2	3	-	1	3	(104,208)
High Gas Price	$ 38,508	164,621	-	-	3	-	4	7	-	-	-	260,351
Low Nuke Cost	$ 38,165	185,738	-	-	-	-	4	8	-	-	1	154,830
High Nuke Cost	$ 38,642	185,738	-	-	-	-	4	8	-	-	1	154,830
High Market Price	$ 38,335	193,923	-	-	-	-	4	8	-	-	1	246,821
Low Market Price	$ 38,134	187,375	-	-	-	-	4	6	-	-	2	21,240
Low Market Capacity	$ 38,411	209,269	-	-	-	-	2	5	-	1	2	47,828
No Market	$ 38,587	209,754	-	-	-	-	2	3	-	1	3	-

Select Strategist Outputs--High Energy Efficiency

Scenario 234 KINE_SHEE_MONE_PRAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,263	162,327	-	-	-	-	-	7	-	-	-	233,605
Mid Externalities, No CO_2 Internal Cost	$ 40,918	174,973	-	-	-	-	-	7	-	-	-	229,747
High Externalities, No CO_2 Internal Cost	$ 44,416	174,973	-	-	-	-	-	7	-	-	-	229,747
High Externalities, Use CO_2 Internal Cost	$ 39,983	157,403	-	-	1	-	-	6	-	-	-	260,861
Low Externalities, No CO_2 Internal Cost	$ 37,415	176,666	-	-	-	-	-	7	-	-	-	224,429
Low Externalities, Use CO_2 Internal Cost	$ 36,348	171,059	-	-	-	-	-	7	-	-	-	222,932
No Externalities, Use CO_2 Internal Cost	$ 35,271	182,893	-	-	-	-	-	5	-	-	1	217,924
No Externalities, No CO_2 Internal Cost	$ 35,271	182,893	-	-	-	-	-	5	-	-	1	217,924
Low Solar Price	$ 37,820	163,548	-	-	-	-	-	7	-	-	-	227,316
High Solar Price	$ 38,637	164,107	-	-	2	-	-	1	-	-	2	263,755
Low Wind Price	$ 37,982	144,817	-	-	3	-	-	5	-	-	-	312,259
High Wind Price	$ 38,270	165,234	-	-	-	-	-	7	-	-	-	221,954
Low Forecast	$ 37,278	159,599	-	-	-	-	-	5	-	-	-	248,141
High Forecast	$ 41,001	176,682	-	-	-	-	6	6	-	-	2	193,189
Low Coal Cost	$ 38,220	162,327	-	-	-	-	-	7	-	-	-	233,605
High Coal Cost	$ 38,306	162,327	-	-	-	-	-	7	-	-	-	233,605
Low Gas Price	$ 38,200	164,578	-	-	-	-	-	1	-	-	3	(2,270)
High Gas Price	$ 38,060	151,306	-	-	2	-	-	5	-	-	-	307,599
Low Nuke Cost	$ 37,688	162,327	-	-	-	-	-	7	-	-	-	233,605
High Nuke Cost	$ 38,839	162,327	-	-	-	-	-	7	-	-	-	233,605
High Market Price	$ 38,026	173,104	-	-	-	-	-	7	-	-	-	315,674
Low Market Price	$ 38,219	149,757	-	-	-	-	-	7	-	-	-	129,500
Low Market Capacity	$ 38,313	166,318	-	-	-	-	-	5	-	-	1	137,204
No Market	$ 38,564	164,986	-	-	-	-	-	3	-	-	2	-

Select Strategist Outputs--High Energy Efficiency

Scenario 235 KINE_SHEE_MONX_PRAE	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,699	177,710	-	-	-	-	1	9	-	-	-	181,399
Mid Externalities, No CO_2 Internal Cost	$ 41,179	190,825	-	-	-	-	1	9	-	-	-	175,039
High Externalities, No CO_2 Internal Cost	$ 44,689	190,825	-	-	-	-	1	9	-	-	-	175,039
High Externalities, Use CO_2 Internal Cost	$ 40,534	167,274	-	-	1	-	1	8	-	-	-	220,586
Low Externalities, No CO_2 Internal Cost	$ 37,651	194,049	-	-	-	-	1	9	-	-	-	172,999
Low Externalities, Use CO_2 Internal Cost	$ 36,614	191,810	-	-	-	-	1	7	-	-	1	165,574
No Externalities, Use CO_2 Internal Cost	$ 35,448	199,617	-	-	-	-	1	7	-	-	1	164,865
No Externalities, No CO_2 Internal Cost	$ 35,448	199,617	-	-	-	-	1	7	-	-	1	164,865
Low Solar Price	$ 38,080	178,318	-	-	-	-	1	9	-	-	-	170,454
High Solar Price	$ 39,142	176,565	-	-	2	-	1	3	-	-	2	217,642
Low Wind Price	$ 38,311	158,727	-	1	2	-	-	7	-	-	-	271,019
High Wind Price	$ 38,704	181,464	-	-	-	-	1	9	-	-	-	168,560
Low Forecast	$ 37,629	170,143	-	-	-	-	-	8	-	-	-	200,497
High Forecast	$ 41,563	195,531	-	-	-	-	6	5	-	1	3	145,858
Low Coal Cost	$ 38,656	177,710	-	-	-	-	1	9	-	-	-	181,399
High Coal Cost	$ 38,741	177,710	-	-	-	-	1	9	-	-	-	181,399
Low Gas Price	$ 38,188	192,164	-	-	-	-	-	1	-	1	3	(76,516)
High Gas Price	$ 38,645	156,149	-	-	3	-	1	6	-	-	-	285,533
Low Nuke Cost	$ 38,280	177,710	-	-	-	-	1	9	-	-	-	181,399
High Nuke Cost	$ 39,118	177,710	-	-	-	-	1	9	-	-	-	181,399
High Market Price	$ 38,562	183,078	-	-	-	-	1	9	-	-	-	279,401
Low Market Price	$ 38,530	168,523	-	-	-	-	1	9	-	-	-	72,197
Low Market Capacity	$ 38,703	186,053	-	-	-	-	1	4	-	-	2	97,142
No Market	$ 38,873	189,084	-	-	-	-	1	4	-	-	2	-

Select Strategist Outputs--High Energy Efficiency

Scenario 236 KINE_SHEE_MONX_P RAX	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 38,598	154,435	-	-	-	-	-	3	-	-	-	270,658
Mid Externalities, No CO_2 Internal Cost	$ 41,360	166,189	-	-	-	-	-	3	-	-	-	266,321
High Externalities, No CO_2 Internal Cost	$ 44,813	164,235	-	-	-	-	-	3	-	-	-	273,037
High Externalities, Use CO_2 Internal Cost	$ 40,210	149,732	-	-	1	-	-	2	-	-	-	293,119
Low Externalities, No CO_2 Internal Cost	$ 37,895	167,882	-	-	-	-	-	3	-	-	-	261,003
Low Externalities, Use CO_2 Internal Cost	$ 36,796	162,530	-	-	-	-	-	3	-	-	-	259,709
No Externalities, Use CO_2 Internal Cost	$ 35,780	167,882	-	-	-	-	-	3	-	-	-	261,003
No Externalities, No CO_2 Internal Cost	$ 35,780	167,882	-	-	-	-	-	3	-	-	-	261,003
Low Solar Price	$ 38,294	153,727	-	-	-	-	-	3	-	-	-	271,177
High Solar Price	$ 38,863	152,875	-	-	1	-	-	2	-	-	-	291,444
Low Wind Price	$ 38,353	140,859	-	-	2	-	-	1	-	-	-	328,965
High Wind Price	$ 38,605	157,341	-	-	-	-	-	3	-	-	-	259,007
Low Forecast	$ 37,654	151,585	-	-	-	-	-	1	-	-	-	282,585
High Forecast	$ 41,148	170,184	-	-	-	-	2	6	-	-	2	227,490
Low Coal Cost	$ 38,556	154,435	-	-	-	-	-	3	-	-	-	270,658
High Coal Cost	$ 38,641	154,435	-	-	-	-	-	3	-	-	-	270,658
Low Gas Price	$ 38,842	144,566	-	-	-	-	-	1	-	-	1	70,165
High Gas Price	$ 38,231	144,185	-	-	2	-	-	1	-	-	-	332,719
Low Nuke Cost	$ 37,859	154,435	-	-	-	-	-	3	-	-	-	270,658
High Nuke Cost	$ 39,338	154,435	-	-	-	-	-	3	-	-	-	270,658
High Market Price	$ 38,288	164,855	-	-	-	-	-	3	-	-	-	344,046
Low Market Price	$ 38,634	139,884	-	-	-	-	-	3	-	-	-	169,958
Low Market Capacity	$ 38,691	155,731	-	-	-	-	-	3	-	-	-	162,947
No Market	$ 39,098	153,340	-	-	-	-	-	1	-	-	1	-

Docket No. E002/RP- 19-368

Attachment 3

Select Strategist Outputs-- No Sherco CC

Department Attachment 3
Select Strategist Outputs--No Sherco CC

Scenario 134a KINE_SHEE_MONE_PRAX (No Sherco CC)	PVSC SYSTEM ($ Million)	CO2 Emissions 2020-'45 (Million tons)	Wind Units 2020-'24	Wind Units 2025-'29	Wind Units 2030-'34	Solar Units 2020-'24	Solar Units 2025-'29	Solar Units 2030-'34	CT Units 2020-'24	CT Units 2025-'29	CT Units 2030-'34	Net Exports 2020-'45 (GWh)
Base Case	$ 36,609	166,301	-	-	-	-	5	5	-	-	3	130,816
Mid Externalities, No CO_2 Internal Cost	$ 38,607	182,608	-	-	-	-	5	5	-	-	3	125,918
High Externalities, No CO_2 Internal Cost	$ 41,734	176,469	-	-	-	-	5	9	-	-	1	140,805
High Externalities, Use CO_2 Internal Cost	$ 38,376	147,612	-	-	1	-	5	6	-	-	2	205,099
Low Externalities, No CO_2 Internal Cost	$ 35,420	185,479	-	-	-	-	3	7	-	1	2	118,089
Low Externalities, Use CO_2 Internal Cost	$ 34,586	179,454	-	-	-	-	3	7	-	1	2	115,083
No Externalities, Use CO_2 Internal Cost	$ 33,452	185,837	-	-	-	-	3	7	-	1	2	117,138
No Externalities, No CO_2 Internal Cost	$ 33,452	185,837	-	-	-	-	3	7	-	1	2	117,138
Low Solar Price	$ 35,868	161,801	-	-	-	-	5	9	-	-	1	138,562
High Solar Price	$ 37,177	158,582	-	-	1	-	3	4	-	1	3	175,284
Low Wind Price	$ 36,221	143,469	-	1	3	-	4	3	-	-	3	241,631
High Wind Price	$ 36,623	171,619	-	-	-	-	5	5	-	-	3	113,718
Low Forecast	$ 35,585	156,897	-	-	-	-	3	7	-	-	2	153,723
High Forecast	$ 39,599	186,288	-	-	-	-	8	5	-	2	4	90,953
Low Coal Cost	$ 36,566	166,301	-	-	-	-	5	5	-	-	3	130,816
High Coal Cost	$ 36,651	166,301	-	-	-	-	5	5	-	-	3	130,816
Low Gas Price	$ 36,086	185,302	-	-	-	-	-	2	-	3	4	(101,809)
High Gas Price	$ 36,465	141,657	-	-	3	-	5	7	-	-	1	254,589
Low Nuke Cost	$ 36,033	166,301	-	-	-	-	5	5	-	-	3	130,816
High Nuke Cost	$ 37,184	166,301	-	-	-	-	5	5	-	-	3	130,816
High Market Price	$ 36,562	166,047	-	-	1	-	5	6	-	-	2	255,627
Low Market Price	$ 36,359	157,238	-	-	-	-	3	7	-	1	2	32,667
Low Market Capacity	$ 36,680	171,515	-	-	-	-	3	5	-	1	3	59,728
No Market	$ 37,029	169,996	-	-	-	-	3	3	-	1	4	-

Docket No. E002/RP- 19-368

Attachment 4

Annual Nameplate Capacity by Type (MW)

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

Scenario 101

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	1,028	1,028	1,028	1,028	1,028
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	546
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,892	1,343	1,717	2,465	2,839
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	1,343	1,343
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	5,159	5,133	5,411	6,899
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	2,389	3,402	5,416	6,429	7,941	7,954
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	2,416	3,429	4,441	5,954
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,429	1,441	1,954

Scenario 102

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	517	517	517	517	517
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	546
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	1,717	2,091	2,839	3,213
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	1,343	1,343
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	5,159	5,133	5,411	6,149
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	3,889	5,402	7,416	7,929	8,441	8,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,902	3,916	4,929	6,441	7,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,916	1,929	1,941	2,454

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

	Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	511	511	511	511	511
S	Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	546
c	Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
e	Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
n	Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
a	Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
r	Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	2,266	1,717	2,091	2,839	3,213
i	Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	1,343	1,343
o	Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
	Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	5,159	5,883	6,161	6,899
1	Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
0	Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
3	Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	2,389	3,902	5,916	6,929	7,441	8,454
	Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,902	3,916	4,929	6,441	7,954
	Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,916	1,929	1,941	2,454

	Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	1,028	1,028	1,028	1,028	1,028
S	Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	1,092	1,092	1,092	1,092	546
c	Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
e	Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
n	Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
a	Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
r	Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,953	1,953	1,892	1,892	1,892	1,343	1,717	2,465	2,839
i	Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	1,343	1,343
o	Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
	Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	5,159	5,133	5,411	6,899
1	Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
0	Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
4	Solar-Max	990	1,062	1,232	1,298	1,321	1,335	2,348	2,862	3,376	3,389	3,402	5,416	6,429	7,941	7,954
	Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	2,416	3,429	4,441	5,954
	Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,429	1,441	1,954

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

Scenario 105

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	1,028	1,028	1,028	1,028	1,028
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,192
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	1,717	2,091
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,911	4,649
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	2,389	2,402	4,416	5,429	6,941	6,954
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,429	3,441	4,954
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,429	1,441	1,954

Scenario 106

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	1,028	1,028	1,028	1,028	1,028
Nuclear	1,738	1,738	1,738	1,738	1,738	1,192	646	646	646	646	646	-	-	-	-
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,953	1,953	1,953	1,892	1,892	2,266	2,091	2,465	2,465	2,465
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,754	4,705	4,534	5,278	6,659	6,633	6,911	6,899
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	2,335	3,348	3,862	4,376	4,389	5,402	7,416	7,929	8,441	8,954
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,862	1,876	1,889	3,402	5,416	6,429	7,441	7,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	2,402	2,416	2,429	2,941	2,954

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

Scenario 107

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	1,028	1,028	1,028	1,028	1,028
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	1,092
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,892	1,343	1,717	1,717	1,717
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	5,159	5,133	4,661	4,649
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	2,389	3,402	5,416	6,429	7,441	7,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	2,416	3,429	3,941	3,954
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,429	1,941	1,954

Scenario 108

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	517	517	517	517	517
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	1,092	1,092	1,092	1,092	546
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,953	1,953	1,892	1,892	1,892	1,717	2,091	2,839	3,213
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	1,343	1,343
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	5,159	5,133	5,411	6,149
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	2,348	2,862	3,376	4,389	4,902	6,916	6,929	7,441	8,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,889	1,902	3,916	4,929	6,441	7,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,916	1,929	1,941	2,454

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

Scenario 109

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	517	517	517	517	517
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,192
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	1,343	2,091	2,465
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	1,343	1,343
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	4,409	4,383	4,661	5,399
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	3,889	3,902	5,916	5,929	6,441	7,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,916	2,929	3,941	5,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,929	1,941	2,454

Scenario 110

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	517	517	517	517	517
Nuclear	1,738	1,738	1,738	1,738	1,738	1,192	646	646	646	646	646	-	-	-	-
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,953	1,953	1,953	1,892	2,266	2,266	2,465	2,839	2,839	2,839
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,892	1,343	1,343	1,343	1,343
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,754	4,705	5,284	6,028	6,659	6,633	6,161	6,149
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	2,335	3,348	3,862	4,376	5,389	6,902	7,916	8,429	8,941	9,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,862	1,876	2,889	3,902	5,916	6,929	7,941	7,954
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	2,902	2,916	2,929	3,441	3,454

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

Scenario 111

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	517	517	517	517	517
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	1,092
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	1,717	2,091	2,091	2,091
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	5,159	5,133	5,411	5,399
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	3,889	5,402	7,416	7,929	7,941	7,954
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,902	3,916	4,929	5,441	5,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,916	1,929	2,441	2,454

Scenario 112

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	-	-	-	-	-
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	546
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	2,266	2,091	2,465	3,213	3,587
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	1,717	2,091
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	1,343	1,343
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	4,528	5,159	5,883	5,411	6,149
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	3,889	5,402	6,416	7,429	7,941	9,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	3,402	5,416	6,429	6,941	7,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	2,402	2,416	2,429	2,441	2,954

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

Scenario 113

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	511	511	511	511	511
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	1,092	1,092	1,092	1,092	546
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,953	1,953	1,892	1,892	1,892	1,717	2,091	2,839	3,213
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	1,343	1,343
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	5,159	5,883	6,161	6,899
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	2,348	2,862	3,376	3,389	4,902	6,916	6,929	7,441	8,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,902	3,916	4,929	6,441	7,954
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,916	1,929	1,941	2,454

Scenario 114

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	511	511	511	511	511
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,192
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	1,343	2,091	2,465
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	1,343	1,343
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	4,409	5,133	5,411	6,149
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	2,389	3,902	5,916	6,429	6,441	7,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,916	2,929	4,441	5,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,929	1,941	2,454

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

Scenario 115

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	511	511	511	511	511
Nuclear	1,738	1,738	1,738	1,738	1,738	1,192	646	646	646	646	646	-	-	-	-
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,953	1,953	1,953	1,892	1,892	2,640	2,839	3,213	3,213	3,213
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,892	1,343	1,343	1,343	1,343
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,892	1,343	1,343	1,343	1,343
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,754	4,705	4,534	5,278	6,659	6,633	6,911	6,899
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	2,335	3,348	3,862	4,376	4,389	5,902	7,916	8,429	9,441	9,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,862	1,876	1,889	3,902	5,916	7,429	7,941	7,954
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	2,402	2,416	2,429	2,441	2,454

Scenario 116

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	511	511	511	511	511
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	1,092
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	2,266	1,717	2,091	2,091	2,091
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	5,159	5,883	6,161	6,149
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	2,389	3,902	5,916	6,929	6,941	6,954
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,902	3,916	4,929	5,441	5,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,916	1,929	2,441	2,454

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

Scenario 117

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	1,028	1,028	1,028	1,028	1,028
Nuclear	1,738	1,738	1,738	1,738	1,738	1,192	646	-	-	-	-	-	-	-	-
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,953	2,701	2,701	2,640	2,640	2,640	2,091	2,465	2,465	2,465
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,953	1,953	1,892	1,892	1,892	1,343	1,343	1,343	1,343
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,863	4,754	4,705	4,534	5,278	6,659	6,633	6,911	6,899
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	2,335	3,348	3,862	3,876	4,389	4,402	6,416	7,929	8,441	8,954
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	2,389	2,402	4,416	5,429	6,441	6,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	2,389	2,402	2,416	2,429	2,941	2,954

Scenario 118

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	1,028	1,028	1,028	1,028	1,028
Nuclear	1,738	1,738	1,738	1,738	1,738	1,192	646	646	646	646	646	646	646	646	646
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,953	1,953	1,953	1,892	1,892	1,892	1,343	1,717	1,717	1,717
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,754	4,705	4,534	4,528	5,909	5,883	6,161	6,149
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	2,335	3,348	3,862	4,376	4,389	4,402	6,416	6,929	7,441	7,954
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,862	1,876	1,889	1,902	3,416	4,429	5,441	5,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	2,416	2,429	2,941	2,954

	Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	1,028	1,028	1,028	1,028	1,028
S	Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	1,092	1,092	1,092	1,092	1,092
c	Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
e	Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
n	Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
a	Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
r	Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,953	1,953	1,892	1,892	1,892	1,343	1,717	1,717	1,717
i	Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
o	Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
	Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	5,159	5,133	4,661	4,649
1	Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
1	Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
9	Solar-Max	990	1,062	1,232	1,298	1,321	1,335	2,348	2,862	3,376	3,389	3,402	5,416	6,429	7,441	7,454
	Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	2,416	3,429	3,941	3,954
	Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,429	1,941	1,954

	Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	1,028	1,028	1,028	1,028	1,028
S	Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738
c	Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
e	Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
n	Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
a	Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
r	Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
i	Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
o	Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
	Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,911	3,899
1	Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
2	Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
0	Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	2,389	2,402	4,416	5,429	6,441	6,454
	Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,429	1,941	1,954
	Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,429	1,441	1,454

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

Scenario 121

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	511	511	511	511	511
Nuclear	1,738	1,738	1,738	1,738	1,738	1,192	646	-	-	-	-	-	-	-	-
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,953	2,701	2,701	2,640	2,640	2,640	2,839	3,213	3,213	3,213
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,953	1,953	1,892	1,892	1,892	1,343	1,343	1,343	1,343
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,863	4,754	4,705	4,534	5,278	6,659	6,633	6,911	6,899
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	2,335	3,348	3,862	3,876	4,389	5,902	7,916	8,429	9,441	9,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	2,389	3,902	5,916	7,429	7,941	7,954
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	2,389	2,402	2,416	2,429	2,441	2,454

Scenario 122

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	511	511	511	511	511
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	1,092	1,092	1,092	1,092	1,092
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,953	1,953	1,892	1,892	1,892	1,717	2,091	2,091	2,091
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	5,159	5,883	6,161	6,149
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	2,348	2,862	3,376	3,389	4,902	6,916	6,929	6,941	6,954
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,902	3,916	4,929	5,441	5,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,916	1,929	2,441	2,454

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

Scenario 123

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	511	511	511	511	511
Nuclear	1,738	1,738	1,738	1,738	1,738	1,192	646	646	646	646	646	646	646	646	646
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,953	1,953	1,953	1,892	1,892	2,266	2,465	2,839	2,839	2,839
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,754	4,705	4,534	5,278	5,909	5,883	5,411	5,399
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	2,335	3,348	3,862	4,376	4,389	5,902	6,916	7,429	8,441	8,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,862	1,876	1,889	3,402	4,916	6,429	6,941	6,954
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,429	1,441	1,454

Scenario 124

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	511	511	511	511	511
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	1,343	1,717	1,717	1,717
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	4,409	5,133	5,411	5,399
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	2,389	3,902	4,916	5,429	5,941	5,954
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,916	2,929	3,441	3,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,429	1,441	1,454

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

Scenario 125

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	517	517	517	517	517
Nuclear	1,738	1,738	1,738	1,738	1,738	1,192	646	-	-	-	-	-	-	-	-
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,953	2,701	2,701	2,640	2,640	2,640	2,465	2,839	2,839	2,839
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,953	1,953	1,892	1,892	1,892	1,343	1,343	1,343	1,343
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,863	4,754	4,705	5,284	6,028	6,659	6,633	6,161	6,149
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	2,335	3,348	3,862	3,876	5,389	5,902	7,916	8,429	8,941	9,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	3,889	3,902	5,916	6,929	7,941	7,954
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	2,889	2,902	2,916	2,929	3,441	3,454

Scenario 126

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	517	517	517	517	517
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	1,092	1,092	1,092	1,092	1,092
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,953	1,953	1,892	1,892	1,892	1,717	2,091	2,091	2,091
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	5,159	5,133	5,411	5,399
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	2,348	2,862	3,376	4,389	4,902	6,916	6,929	6,941	6,954
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,889	1,902	3,916	4,929	5,441	5,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,916	1,929	2,441	2,454

Department Attachment 4

Annual Nameplate Capacity by Type (MW)

Scenario 127

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	517	517	517	517	517
Nuclear	1,738	1,738	1,738	1,738	1,738	1,192	646	646	646	646	646	646	646	646	646
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,953	1,953	1,953	1,892	2,266	2,266	2,091	2,465	2,465	2,465
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,754	4,705	5,284	5,278	5,909	5,883	6,161	6,149
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	2,335	3,348	3,862	4,376	5,389	5,902	6,916	7,429	7,941	8,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,862	1,876	2,889	2,902	4,916	6,429	6,941	6,954
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,916	1,929	2,441	2,454

Scenario 128

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	517	517	517	517	517
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	1,343	1,717	1,717
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	4,409	4,383	4,661	4,649
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	3,889	3,902	5,916	5,929	5,941	5,954
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,916	2,929	3,441	3,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,929	2,441	2,454

Department Attachment 4

Annual Nameplate Capacity by Type (MW)

	Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	-	-	-	-	-
S	Nuclear	1,738	1,738	1,738	1,738	1,738	1,192	646	646	646	646	646	-	-	-	-
c	Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
e	Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
n	Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
a	Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
r	Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,953	1,953	1,953	1,892	2,266	3,388	3,587	3,961	3,961	3,961
i	Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	2,266	1,717	2,091	2,091	2,091
o	Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,892	1,343	1,343	1,343	1,343
	Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,754	4,705	5,284	6,028	6,659	6,633	6,911	6,899
1	Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
2	Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
9	Solar-Max	990	1,062	1,232	1,298	1,321	2,335	3,348	3,862	4,376	5,389	7,402	8,416	8,929	8,941	8,954
	Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,862	1,876	2,889	4,402	6,416	6,929	7,441	7,454
	Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,902	1,916	1,929	1,941	1,954

	Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	-	-	-	-	-
S	Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	1,092
c	Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
e	Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
n	Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
a	Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
r	Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	2,266	2,091	2,465	2,839	2,839
i	Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
o	Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
	Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	4,528	5,159	5,883	5,411	5,399
1	Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
3	Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
0	Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	3,889	5,402	6,416	7,429	7,441	7,954
	Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	3,402	5,416	6,429	7,441	7,454
	Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	2,402	2,416	2,429	2,441	2,454

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

Scenario 131

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	-	-	-	-	-
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	1,092	1,092	1,092	1,092	546
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,953	1,953	1,892	1,892	1,892	2,091	2,465	3,213	3,587
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	1,717	2,091
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	1,343	1,343
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	4,528	5,159	5,883	5,411	6,149
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	2,348	2,862	3,376	4,389	6,402	6,416	7,429	7,941	9,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,889	3,402	5,416	6,429	6,941	7,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	2,402	2,416	2,429	2,441	2,954

Scenario 132

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	-	-	-	-	-
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,192
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,892	1,717	2,091	2,839	3,213
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	1,343	1,717
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	4,528	4,409	5,133	5,411	6,149
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	3,889	5,402	5,416	5,929	6,941	7,954
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,902	3,416	4,429	5,941	6,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,429	1,441	1,954

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

Scenario 133

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	-	-	-	-	-
Nuclear	1,738	1,738	1,738	1,738	1,738	1,192	646	-	-	-	-	-	-	-	-
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,953	2,327	2,327	2,266	2,640	3,388	3,587	3,961	3,961	3,961
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,953	1,953	1,892	1,892	1,892	1,717	2,091	2,091	2,091
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	1,343	1,343	1,343	1,343
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,863	4,754	4,705	5,284	6,028	6,659	6,633	6,911	6,899
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	2,335	3,848	4,862	4,876	6,389	7,902	8,416	8,929	9,441	9,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	3,889	5,402	6,416	6,929	7,441	7,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,848	1,862	1,876	1,889	1,902	1,916	1,929	1,941	1,954

Scenario 134

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	-	-	-	-	-
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	1,092	1,092	1,092	1,092	1,092
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,953	1,953	1,892	1,892	2,640	2,465	2,839	2,839	2,839
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	4,528	5,159	5,883	5,411	5,399
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	2,348	2,862	3,376	4,389	6,402	6,416	7,429	7,441	7,954
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,889	3,402	5,416	6,429	7,441	7,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,429	1,941	1,954

Department Attachment 4
Annual Nameplate Capacity by Type (MW)

Scenario 135

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	-	-	-	-	-
Nuclear	1,738	1,738	1,738	1,738	1,738	1,192	646	646	646	646	646	646	646	646	646
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,953	1,953	1,953	1,892	2,266	2,640	2,839	3,213	3,213	3,213
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	1,343	1,717	1,717	1,717
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,754	4,705	5,284	6,028	5,909	5,883	6,161	6,149
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	2,335	3,348	3,862	4,376	5,389	7,402	7,416	7,929	8,441	8,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,862	1,876	2,889	4,402	5,416	5,929	6,441	6,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,902	1,916	1,929	2,441	2,454

Scenario 136

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	-	-	-	-	-
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738
Gas CC	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,837	2,837	2,592	2,592	2,592	2,294	2,294	2,294
Oil CT	421	421	421	421	230	230	230	230	230	230	230	-	-	-	-
Other	140	140	140	114	111	77	77	77	42	42	42	27	27	27	27
Hydro	1,112	1,162	1,162	1,162	1,162	312	312	312	312	312	312	312	312	312	312
Gas CT-Max	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,892	1,717	2,091	2,091	2,091
Gas CT-Base	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Gas CT-Min	1,937	1,937	1,937	1,937	1,937	1,579	1,579	1,579	1,518	1,518	1,518	969	969	969	969
Wind-Max	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	4,528	4,409	5,133	5,411	5,399
Wind-Base	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Wind-Min	3,732	4,023	4,420	4,270	4,184	4,148	4,113	4,004	3,955	3,784	3,778	3,659	3,633	3,161	3,149
Solar-Max	990	1,062	1,232	1,298	1,321	1,335	1,848	2,362	2,376	3,889	5,402	5,416	5,929	6,441	6,454
Solar-Base	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,902	3,416	4,429	5,441	5,454
Solar-Min	990	1,062	1,232	1,298	1,321	1,335	1,348	1,362	1,376	1,389	1,402	1,416	1,429	1,941	1,954

Docket No. E002/RP- 19-368

Attachment 5

Annual Energy by Type (GWh)

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 101

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	5,227	6,473	6,880	6,378	6,568	6,803
Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,457	2,994	2,910	2,620	2,962	2,949
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,739	2,034	2,019	1,766	1,997	2,025
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	6,827	3,632
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,657	6,763	3,514
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	11,907	8,152	8,182	6,373	3,056
Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,634	16,137	16,446	14,958	12,980	12,633
Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,867	14,518	14,572	13,079	12,722	12,266
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,129	5,773	6,881	6,099	5,643	5,764
Oil CT-Max	9	15	14	14	5	6	7	6	6	5	5	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	2	1	1	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	1	0	0	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	459	460	459	285	285	285	202	202	202	198
Other-Min	840	792	775	679	625	417	418	402	277	276	276	191	195	195	174
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	502	477	469	452	556	211	223	406	628
Gas CT-Base	664	509	470	705	661	180	153	199	189	185	261	120	118	187	147
Gas CT-Min	192	145	94	84	81	53	38	78	77	57	64	59	31	38	32
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	21,466	21,353	22,385	28,613
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	4,333	6,279	10,154	12,129	15,010	15,030
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	4,372	6,334	8,265	11,175
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	2,471	2,483	3,466
Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,640	1,788	3,593	4,335	6,822	9,072
Imports-Base	580	922	473	356	270	535	489	99	104	181	171	464	615	1,050	1,870
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,823	14,821	13,413	13,455	14,268	14,550
Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,497	12,519	10,714	10,539	8,793	8,050
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Scenario 102

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	3,447	3,960	3,998	3,507	3,915	3,933
Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,010	2,406	2,343	2,091	2,325	2,328
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,700	1,938	1,974	1,711	1,961	1,973
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	6,827	3,632
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,595	8,468	6,527	3,356
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	11,750	8,221	8,065	6,231	3,044
Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,441	15,659	14,901	13,312	12,837	13,470
Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,701	14,070	13,303	11,740	11,074	10,907
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,135	5,264	6,969	6,116	5,639	5,808
Oil CT-Max	9	15	14	14	5	6	7	6	6	8	7	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	2	1	2	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	1	1	1	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	459	460	459	285	285	285	202	199	199	194
Other-Min	840	792	775	679	625	417	418	402	277	276	273	193	190	192	177
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	502	477	469	653	712	468	445	722	1,113
Gas CT-Base	664	509	470	705	661	180	153	199	189	376	429	185	170	309	315
Gas CT-Min	192	145	94	84	81	53	38	78	77	81	96	103	86	95	123
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	21,466	21,353	22,385	25,328
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	7,224	10,134	14,008	15,027	15,973	15,993
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	3,389	7,263	9,232	12,119	14,066
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	3,408	3,437	3,447	4,430
Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,691	1,629	3,170	3,854	6,191	8,373
Imports-Base	580	922	473	356	270	535	489	99	104	240	210	495	667	1,070	1,986
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,212	14,634	14,112	14,057	14,439	14,464
Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,135	12,621	11,666	11,325	9,861	8,603
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 103

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	5,227	2,638	2,869	2,931	2,609	2,734
Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,457	572	403	398	444	435
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,739	78	73	92	67	90
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	6,827	3,632
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,595	8,468	6,527	3,291
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	11,750	8,309	8,065	6,231	3,044
Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,634	16,230	15,711	14,088	13,088	12,831
Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,867	14,423	13,886	12,316	11,398	10,921
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,129	6,363	6,871	6,048	5,675	5,922
Oil CT-Max	9	15	14	14	5	6	7	6	6	5	8	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	2	1	1	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	1	0	1	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	459	460	459	285	285	285	202	201	199	191
Other-Min	840	792	775	679	625	417	418	402	277	276	273	194	194	192	177
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	502	477	469	452	606	403	454	844	1,214
Gas CT-Base	664	509	470	705	661	180	153	199	189	185	303	130	108	165	149
Gas CT-Min	192	145	94	84	81	53	38	78	77	57	100	74	54	62	97
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	21,466	24,648	25,670	28,613
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	4,333	7,243	11,117	13,095	14,046	15,993
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	3,389	7,263	9,232	12,119	15,030
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	3,408	3,437	3,447	4,430
Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,640	2,290	4,196	4,857	7,659	9,893
Imports-Base	580	922	473	356	270	535	489	99	104	181	357	733	914	1,635	2,733
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,823	13,375	13,239	14,157	13,885	13,807
Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,497	11,179	10,532	10,414	8,799	8,017
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 104

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,634	8,535	9,225	9,124	5,799	5,800	5,388	6,653	6,879	6,378	6,568	6,803
Coal-Base	10,193	7,181	7,514	8,821	7,789	3,339	3,155	2,809	2,832	2,560	3,099	2,910	2,620	2,962	2,949
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,878	2,048	2,046	1,740	2,033	2,019	1,766	1,997	2,025
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640	8,658	8,666	6,827	3,632
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640	8,658	8,657	6,763	3,514
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	11,939	8,396	8,319	8,387	8,359	8,152	8,182	6,373	3,056
Gas CC-Max	11,777	10,420	9,399	11,350	11,462	14,522	13,085	18,008	16,895	16,987	17,067	16,446	14,958	12,980	12,633
Gas CC-Base	9,677	8,975	8,305	9,996	9,776	12,309	10,772	16,101	14,859	14,710	15,085	14,575	13,079	12,722	12,266
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,874	8,263	7,329	6,907	7,289	6,880	6,099	5,643	5,764
Oil CT-Max	9	15	14	14	5	6	7	10	12	10	10	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	1	1	1	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	459	460	461	285	285	285	202	202	202	198
Other-Min	840	792	775	679	625	417	420	410	276	276	276	191	195	195	174
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	526	545	557	521	624	211	223	406	628
Gas CT-Base	664	509	470	705	661	180	154	204	192	183	269	120	118	187	147
Gas CT-Min	192	145	94	84	81	53	39	76	75	56	64	59	31	38	32
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	21,466	21,353	22,385	28,613
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	4,271	5,255	6,254	6,260	6,279	10,154	12,129	15,010	15,030
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	4,372	6,334	8,265	11,175
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	2,471	2,483	3,466
Imports-Max	1,666	2,042	1,186	997	893	3,117	3,586	3,380	3,578	3,704	3,283	3,593	4,335	6,822	9,072
Imports-Base	580	922	473	356	270	535	884	523	619	680	463	464	615	1,050	1,870
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,182	16,262	12,984	11,849	12,224	11,848	11,728	12,476	13,413	13,455	14,268	14,550
Exports-Base	9,123	8,952	11,297	13,978	13,805	9,807	8,662	9,783	9,367	9,021	9,832	10,717	10,539	8,793	8,050
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Scenario 105	Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	5,227	6,356	6,720	6,329	6,531	6,796
	Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,457	2,942	2,793	2,570	2,750	2,800
	Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,739	2,037	2,001	1,743	1,985	1,994
	Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	11,744	9,005
	Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	11,744	8,873
	Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	13,559	13,233	13,679	11,413	8,662
	Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,634	15,526	15,576	14,735	14,358	13,880
	Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,867	14,099	14,010	13,047	12,565	12,053
	Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,129	4,873	5,021	5,043	5,629	5,712
	Oil CT-Max	9	15	14	14	5	6	7	6	6	5	6	-	-	-	-
	Oil CT-Base	6	13	12	11	4	2	2	2	1	1	2	-	-	-	-
	Oil CT-Min	6	4	3	2	1	0	0	0	1	0	1	-	-	-	-
	Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
	Other-Base	858	811	820	720	671	459	460	459	285	285	285	202	203	202	201
	Other-Min	840	792	775	679	625	417	418	402	277	276	277	198	198	197	197
	Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Gas CT-Max	883	695	607	916	881	581	502	477	469	452	529	194	196	198	397
	Gas CT-Base	664	509	470	705	661	180	153	199	189	185	259	116	119	109	83
	Gas CT-Min	192	145	94	84	81	53	38	78	77	57	66	46	20	42	45
	Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	15,815	18,758
	Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	4,333	4,352	8,226	10,198	13,083	13,102
	Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	2,471	6,337	9,248
	Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	2,471	2,483	3,466
	Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,640	1,210	1,570	1,912	3,478	4,944
	Imports-Base	580	922	473	356	270	535	489	99	104	181	77	183	261	422	731
	Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,823	15,743	14,719	13,835	12,994	12,494
	Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,497	13,640	12,769	11,743	10,801	9,962
	Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 106

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,634	8,642	9,527	9,386	5,865	5,836	5,561	6,595	6,857	6,359	6,393	6,624
Coal-Base	10,193	7,181	7,514	8,821	7,851	3,456	3,276	2,837	2,878	2,599	3,067	2,850	2,577	2,585	2,699
Coal-Min	7,522	4,683	4,262	4,365	4,468	2,197	1,878	2,044	2,049	1,738	2,044	2,037	1,796	2,013	2,020
Nuclear-Max	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	3,676	-	-	-	-
Nuclear-Base	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	3,668	-	-	-	-
Nuclear-Min	14,053	13,535	13,676	13,370	12,750	8,036	5,210	4,759	5,105	4,754	3,336	-	-	-	-
Gas CC-Max	11,777	10,420	9,399	11,350	11,773	15,335	13,753	18,543	17,299	17,323	17,003	16,190	14,459	13,298	13,495
Gas CC-Base	9,677	8,975	8,305	9,996	10,016	12,666	11,054	16,332	15,032	14,917	14,883	14,140	12,473	11,609	11,707
Gas CC-Min	5,308	5,427	3,978	3,924	3,769	5,946	4,859	8,186	7,317	6,774	7,391	7,160	6,336	5,940	6,102
Oil CT-Max	9	15	14	14	5	14	20	16	16	16	11	-	-	-	-
Oil CT-Base	6	13	12	11	3	2	2	1	1	1	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
Other-Max	860	814	823	721	673	464	465	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	457	459	461	285	285	284	199	196	190	194
Other-Min	840	792	775	679	629	416	423	410	272	273	259	182	177	169	171
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	907	681	637	592	590	559	599	569	870	1,088	1,101
Gas CT-Base	664	509	470	705	670	190	166	207	196	190	255	111	93	87	82
Gas CT-Min	192	145	94	84	93	54	38	80	77	59	73	63	44	37	33
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	19,008	18,979	18,468	21,681	28,036	27,943	28,955	28,613
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	4,251	6,198	7,183	8,186	8,187	10,134	14,008	15,027	15,973	16,957
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	3,328	3,357	3,369	6,279	10,154	12,129	14,046	14,066
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	4,352	4,372	4,402	5,374	5,394
Imports-Max	1,666	2,042	1,186	997	1,070	5,974	7,682	4,928	4,840	5,313	5,148	7,854	8,955	10,193	10,540
Imports-Base	580	922	473	356	348	1,895	3,019	1,126	1,160	1,333	1,071	1,944	2,394	3,003	3,106
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,182	15,726	9,348	7,160	10,396	10,342	9,811	12,262	13,393	13,785	13,788	13,679
Exports-Base	9,123	8,952	11,297	13,978	13,184	6,225	4,278	7,872	7,820	7,152	9,008	8,587	8,403	7,629	7,397
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 107

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	5,227	6,473	6,879	6,377	6,595	6,817
Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,457	2,994	2,910	2,619	2,792	2,897
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,739	2,034	2,019	1,766	1,983	1,989
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,657	8,640	8,631
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	11,907	8,152	8,182	8,314	8,323
Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,634	16,137	16,446	14,960	14,136	14,387
Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,865	14,518	14,575	13,076	12,740	12,845
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,130	5,773	6,880	6,101	5,589	5,673
Oil CT-Max	9	15	14	14	5	6	7	6	6	5	5	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	2	1	1	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	1	0	0	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	459	460	459	285	285	285	202	202	202	202
Other-Min	840	792	775	679	625	417	418	402	277	276	276	191	195	195	199
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	502	477	469	452	556	211	223	230	239
Gas CT-Base	664	509	470	705	661	180	153	199	189	185	261	120	118	108	106
Gas CT-Min	192	145	94	84	81	53	38	78	77	57	64	59	31	41	41
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	21,466	21,353	19,100	18,758
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	4,333	6,279	10,154	12,129	14,046	14,066
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	4,372	6,334	7,301	7,321
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	2,471	3,447	3,466
Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,640	1,788	3,593	4,334	4,824	5,111
Imports-Base	580	922	473	356	270	535	489	99	104	181	171	464	615	751	790
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,823	14,821	13,413	13,455	13,039	12,847
Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,495	12,519	10,717	10,536	9,213	8,869
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 108

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,634	8,535	9,225	9,124	5,799	5,800	3,456	3,983	3,998	3,507	3,915	3,933
Coal-Base	10,193	7,181	7,514	8,821	7,789	3,339	3,155	2,809	2,832	2,054	2,468	2,343	2,091	2,325	2,328
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,878	2,048	2,046	1,699	1,976	1,974	1,711	1,961	1,973
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640	8,658	8,666	6,827	3,632
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640	8,595	8,468	6,527	3,356
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	11,939	8,396	8,319	8,271	8,250	8,309	8,065	6,231	3,044
Gas CC-Max	11,777	10,420	9,399	11,350	11,462	14,522	13,085	18,008	16,895	16,624	16,647	14,901	13,312	12,837	13,470
Gas CC-Base	9,677	8,975	8,305	9,996	9,776	12,309	10,772	16,101	14,859	14,419	14,728	13,304	11,740	11,074	10,907
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,874	8,263	7,329	6,880	7,333	6,969	6,116	5,639	5,808
Oil CT-Max	9	15	14	14	5	6	7	10	12	16	15	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	1	1	2	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	0	1	1	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	288	202	203	202	202
Other-Base	858	811	820	720	671	459	460	461	285	285	285	202	199	199	194
Other-Min	840	792	775	679	625	417	420	410	276	275	276	193	190	192	177
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	526	545	557	691	767	468	463	722	1,113
Gas CT-Base	664	509	470	705	661	180	154	204	192	391	455	185	170	309	315
Gas CT-Min	192	145	94	84	81	53	39	76	75	79	95	103	86	95	123
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	21,466	21,353	22,385	25,328
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	4,271	5,255	6,254	8,187	9,170	13,044	13,095	14,046	15,993
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	3,369	3,389	7,263	9,232	12,119	14,066
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	3,408	3,437	3,447	4,430
Imports-Max	1,666	2,042	1,186	997	893	3,117	3,586	3,380	3,578	3,301	2,938	3,170	3,854	6,191	8,373
Imports-Base	580	922	473	356	270	535	884	523	619	660	505	495	667	1,070	1,986
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,182	16,262	12,984	11,849	12,224	11,848	11,777	12,302	14,111	14,057	14,439	14,464
Exports-Base	9,123	8,952	11,297	13,978	13,805	9,807	8,662	9,783	9,367	9,377	10,034	11,667	11,325	9,861	8,603
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

	Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	3,447	3,988	4,012	3,504	3,946	3,952
	Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,010	2,397	2,310	2,049	2,422	2,433
	Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,700	1,951	1,932	1,699	1,954	1,961
	Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	11,744	9,005
	Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	11,721	8,798
	Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	13,559	13,086	13,506	11,385	8,379
	Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,441	15,327	14,750	13,286	12,320	12,948
	Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,701	13,863	13,329	11,860	12,173	11,530
	Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,135	4,864	4,525	4,565	5,646	5,702
	Oil CT-Max	9	15	14	14	5	6	7	6	6	8	7	-	-	-	-
S	Oil CT-Base	6	13	12	11	4	2	2	2	1	2	3	-	-	-	-
c	Oil CT-Min	6	4	3	2	1	0	0	0	1	1	1	-	-	-	-
e	Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
n	Other-Base	858	811	820	720	671	459	460	459	285	285	285	202	203	202	199
a	Other-Min	840	792	775	679	625	417	418	402	277	276	279	194	197	199	194
r	Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
i	Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
o	Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Gas CT-Max	883	695	607	916	881	581	502	477	469	653	711	294	396	488	630
1	Gas CT-Base	664	509	470	705	661	180	153	199	189	376	429	189	188	344	319
0	Gas CT-Min	192	145	94	84	81	53	38	78	77	81	96	53	71	71	85
9	Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	18,181	18,059	19,100	22,043
	Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	7,224	7,243	11,117	11,164	12,119	14,066
	Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	3,408	5,368	7,301	10,212
	Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	3,437	3,447	4,430
	Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,691	1,276	1,389	1,611	3,049	4,489
	Imports-Base	580	922	473	356	270	535	489	99	104	240	130	212	223	420	754
	Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,212	15,014	14,243	14,421	14,787	14,917
	Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,135	13,088	12,648	12,801	11,194	10,138
	Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Scenario 110	Coal-Max	11,494	8,192	8,380	9,634	8,642	9,527	9,386	5,865	5,836	3,457	3,944	3,926	3,486	3,818	3,853
	Coal-Base	10,193	7,181	7,514	8,821	7,851	3,456	3,276	2,837	2,878	2,059	2,513	2,448	2,158	2,246	2,321
	Coal-Min	7,522	4,683	4,262	4,365	4,468	2,197	1,878	2,053	2,055	1,707	1,983	1,983	1,719	1,898	1,901
	Nuclear-Max	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	3,676	-	-	-	-
	Nuclear-Base	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	3,639	-	-	-	-
	Nuclear-Min	14,053	13,535	13,676	13,370	12,750	8,036	5,210	4,759	5,105	4,641	3,261	-	-	-	-
	Gas CC-Max	11,777	10,420	9,399	11,350	11,773	15,335	13,753	18,543	17,299	16,736	15,129	14,591	12,850	12,626	12,703
	Gas CC-Base	9,677	8,975	8,305	9,996	10,016	12,666	11,054	16,332	15,032	14,495	14,564	13,657	12,009	11,126	11,254
	Gas CC-Min	5,308	5,427	3,978	3,924	3,769	5,946	4,859	8,269	7,290	6,902	7,426	7,102	6,312	5,858	6,022
	Oil CT-Max	9	15	14	14	5	14	20	16	16	21	11	-	-	-	-
	Oil CT-Base	6	13	12	11	3	2	2	1	1	2	1	-	-	-	-
	Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
	Other-Max	860	814	823	721	673	464	465	465	287	286	287	202	203	202	202
	Other-Base	858	811	820	720	671	457	459	461	285	285	283	196	191	191	191
	Other-Min	840	792	775	679	629	416	423	412	272	262	260	173	171	179	178
	Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Gas CT-Max	883	695	607	916	907	681	637	592	590	699	760	833	1,264	1,630	1,774
	Gas CT-Base	664	509	470	705	670	190	166	207	196	386	595	375	356	311	322
	Gas CT-Min	192	145	94	84	93	54	38	89	83	105	131	134	123	106	111
	Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	19,008	18,979	21,753	24,966	28,036	27,943	25,670	25,328
	Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Solar-Max	1,730	1,853	2,154	2,266	2,308	4,251	6,198	7,183	8,186	10,114	13,025	14,972	15,993	16,937	17,920
	Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	3,328	3,357	5,296	7,243	11,117	13,095	15,010	15,030
	Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	5,316	5,336	5,368	6,337	6,357
	Imports-Max	1,666	2,042	1,186	997	1,070	5,974	7,682	5,346	5,362	5,824	4,787	7,349	8,369	9,624	9,976
	Imports-Base	580	922	473	356	348	1,895	3,019	1,126	1,160	1,187	1,091	1,973	2,429	3,063	3,156
	Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Exports-Max	12,295	11,133	13,183	16,182	15,726	9,348	7,160	10,396	10,342	11,555	13,901	13,660	14,082	13,512	13,372
	Exports-Base	9,123	8,952	11,297	13,978	13,184	6,225	4,278	7,872	7,820	8,166	9,402	8,847	8,608	7,824	7,590
	Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 111

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	3,447	3,960	3,998	3,507	3,940	3,963
Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,010	2,406	2,343	2,091	2,273	2,347
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,700	1,938	1,974	1,711	1,955	1,958
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,595	8,468	8,457	8,448
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	11,750	8,221	8,065	8,183	8,189
Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,441	15,659	14,901	13,310	12,584	12,782
Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,701	14,070	13,304	11,740	11,378	11,449
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,135	5,264	6,969	6,116	5,499	5,631
Oil CT-Max	9	15	14	14	5	6	7	6	6	8	7	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	2	1	2	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	1	1	1	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	459	460	459	285	285	285	202	199	200	201
Other-Min	840	792	775	679	625	417	418	402	277	276	273	193	190	194	194
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	502	477	469	653	712	468	539	468	486
Gas CT-Base	664	509	470	705	661	180	153	199	189	376	429	185	170	159	159
Gas CT-Min	192	145	94	84	81	53	38	78	77	81	96	103	86	72	75
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	21,466	21,353	22,385	22,043
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	7,224	10,134	14,008	15,027	15,010	15,030
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	3,389	7,263	9,232	10,192	10,212
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	3,408	3,437	4,410	4,430
Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,691	1,629	3,170	3,854	4,429	4,649
Imports-Base	580	922	473	356	270	535	489	99	104	240	210	495	667	830	899
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,212	14,634	14,111	14,055	14,567	14,377
Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,135	12,621	11,667	11,325	10,002	9,651
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

	Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	3,447	-	-	-	-	-
	Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,010	-	-	-	-	-
	Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,700	-	-	-	-	-
	Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	6,827	3,632
	Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,295	8,398	8,261	6,431	3,356
	Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	11,518	8,152	8,066	6,177	3,051
	Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,441	14,917	14,156	13,106	12,795	12,441
	Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,701	13,295	12,212	10,603	10,819	11,110
	Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,135	5,856	6,905	6,081	5,652	5,914
	Oil CT-Max	9	15	14	14	5	6	7	6	6	8	7	-	-	-	-
S	Oil CT-Base	6	13	12	11	4	2	2	2	1	2	2	-	-	-	-
c	Oil CT-Min	6	4	3	2	1	0	0	0	1	1	0	-	-	-	-
e	Other-Max	860	814	823	721	673	463	463	465	287	286	288	202	203	202	202
n	Other-Base	858	811	820	720	671	459	460	459	285	285	284	200	198	197	194
a	Other-Min	840	792	775	679	625	417	418	402	277	276	272	193	192	190	179
r	Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
i	Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
o	Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Gas CT-Max	883	695	607	916	881	581	502	477	469	653	838	661	933	1,329	2,003
1	Gas CT-Base	664	509	470	705	661	180	153	199	189	376	498	212	222	494	543
1	Gas CT-Min	192	145	94	84	81	53	38	78	77	81	171	113	155	164	206
2	Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	18,396	21,466	24,648	22,385	25,328
	Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	7,224	10,134	12,081	14,061	15,010	17,920
	Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	6,279	10,154	12,129	13,083	14,066
	Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	4,352	4,372	4,402	4,410	5,394
	Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,691	2,100	3,808	4,407	7,051	9,244
	Imports-Base	580	922	473	356	270	535	489	99	104	240	350	826	1,028	1,711	2,904
	Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,212	14,139	13,652	14,386	12,737	13,040
	Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,135	12,342	11,089	10,786	8,883	7,681
	Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario	Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Scenario 113	Coal-Max	11,494	8,192	8,380	9,634	8,535	9,225	9,124	5,799	5,800	5,388	2,709	2,871	2,931	2,609	2,734
	Coal-Base	10,193	7,181	7,514	8,821	7,789	3,339	3,155	2,809	2,832	2,560	604	403	398	444	435
	Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,878	2,048	2,046	1,740	78	73	92	67	90
	Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640	8,658	8,666	6,827	3,632
	Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640	8,595	8,468	6,527	3,291
	Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	11,939	8,396	8,319	8,387	8,250	8,309	8,065	6,231	3,044
	Gas CC-Max	11,777	10,420	9,399	11,350	11,462	14,522	13,085	18,008	16,895	16,987	17,039	15,713	14,088	13,088	12,831
	Gas CC-Base	9,677	8,975	8,305	9,996	9,776	12,309	10,772	16,101	14,859	14,710	14,891	13,886	12,316	11,398	10,921
	Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,874	8,263	7,329	6,907	7,217	6,871	6,048	5,675	5,922
	Oil CT-Max	9	15	14	14	5	6	7	10	12	10	18	-	-	-	-
	Oil CT-Base	6	13	12	11	4	2	2	1	1	1	2	-	-	-	-
	Oil CT-Min	6	4	3	2	1	0	0	0	0	0	1	-	-	-	-
	Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
	Other-Base	858	811	820	720	671	459	460	461	285	285	285	202	201	199	191
	Other-Min	840	792	775	679	625	417	420	410	276	276	275	194	194	192	177
	Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Gas CT-Max	883	695	607	916	881	581	526	545	557	521	674	403	454	844	1,214
	Gas CT-Base	664	509	470	705	661	180	154	204	192	183	310	130	108	165	149
	Gas CT-Min	192	145	94	84	81	53	39	76	75	56	97	74	54	62	97
	Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	21,466	24,648	25,670	28,613
	Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	4,271	5,255	6,254	6,260	9,170	13,044	13,095	14,046	15,993
	Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	3,389	7,263	9,232	12,119	15,030
	Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	3,408	3,437	3,447	4,430
	Imports-Max	1,666	2,042	1,186	997	893	3,117	3,586	3,380	3,578	3,704	3,900	4,196	4,857	7,659	9,893
	Imports-Base	580	922	473	356	270	535	884	523	619	680	812	733	914	1,635	2,733
	Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Exports-Max	12,295	11,133	13,183	16,182	16,262	12,984	11,849	12,224	11,848	11,728	10,879	13,239	14,157	13,885	13,807
	Exports-Base	9,123	8,952	11,297	13,978	13,805	9,807	8,662	9,783	9,367	9,021	8,496	10,532	10,414	8,799	8,017
	Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

	Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	5,227	2,616	2,912	2,836	2,584	2,711
	Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,457	566	390	381	481	495
	Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,739	79	54	79	52	64
	Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	11,744	9,005
	Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	11,662	8,798
	Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	13,559	13,086	13,506	11,292	8,379
	Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,634	15,972	15,668	14,177	13,090	12,819
	Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,867	14,342	13,967	12,504	12,101	11,911
	Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,129	5,897	5,574	5,519	5,531	5,694
	Oil CT-Max	9	15	14	14	5	6	7	6	6	5	8	-	-	-	-
S	Oil CT-Base	6	13	12	11	4	2	2	2	1	1	2	-	-	-	-
c	Oil CT-Min	6	4	3	2	1	0	0	0	1	0	1	-	-	-	-
e	Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
n	Other-Base	858	811	820	720	671	459	460	459	285	285	285	202	203	201	199
a	Other-Min	840	792	775	679	625	417	418	402	277	276	276	194	197	194	193
r	Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
i	Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
o	Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Gas CT-Max	883	695	607	916	881	581	502	477	469	452	599	220	250	467	544
1	Gas CT-Base	664	509	470	705	661	180	153	199	189	185	311	136	137	213	176
1	Gas CT-Min	192	145	94	84	81	53	38	78	77	57	99	65	44	69	70
4	Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	18,181	21,353	22,385	25,328
	Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	4,333	7,243	11,117	12,129	12,119	14,066
	Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	3,408	5,368	8,265	10,212
	Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	3,437	3,447	4,430
	Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,640	1,882	2,030	2,270	4,175	5,769
	Imports-Base	580	922	473	356	270	535	489	99	104	181	220	338	320	664	1,204
	Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,823	13,807	13,315	14,304	14,448	14,245
	Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,497	11,724	11,456	11,830	10,189	8,949
	Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Scenario 115

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,634	8,642	9,527	9,386	5,865	5,836	5,561	2,676	2,981	2,965	2,725	2,913
Coal-Base	10,193	7,181	7,514	8,821	7,851	3,456	3,276	2,837	2,878	2,599	665	535	488	431	472
Coal-Min	7,522	4,683	4,262	4,365	4,468	2,197	1,878	2,053	2,055	1,743	102	100	126	95	102
Nuclear-Max	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	3,676	-	-	-	-
Nuclear-Base	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	3,639	-	-	-	-
Nuclear-Min	14,053	13,535	13,676	13,370	12,750	8,036	5,210	4,759	5,105	4,754	3,261	-	-	-	-
Gas CC-Max	11,777	10,420	9,399	11,350	11,773	15,335	13,753	18,543	17,299	17,323	16,885	16,103	13,997	13,176	13,392
Gas CC-Base	9,677	8,975	8,305	9,996	10,016	12,666	11,054	16,332	15,032	14,917	14,664	14,006	12,025	11,406	11,609
Gas CC-Min	5,308	5,427	3,978	3,924	3,769	5,946	4,859	8,269	7,290	6,813	7,351	7,246	6,490	6,123	6,307
Oil CT-Max	9	15	14	14	5	14	20	16	16	16	13	-	-	-	-
Oil CT-Base	6	13	12	11	3	2	2	1	1	1	1	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
Other-Max	860	814	823	721	673	464	465	465	287	286	286	202	203	202	202
Other-Base	858	811	820	720	671	457	459	461	285	285	282	197	192	190	191
Other-Min	840	792	775	679	629	416	423	412	272	273	255	181	182	172	175
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	907	681	637	592	590	559	844	1,073	1,355	1,485	1,502
Gas CT-Base	664	509	470	705	670	190	166	207	196	190	416	214	180	172	165
Gas CT-Min	192	145	94	84	93	54	38	89	83	62	137	107	114	101	103
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	19,008	18,979	18,468	21,681	28,036	27,943	28,955	28,613
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	4,251	6,198	7,183	8,186	8,187	11,097	14,972	15,993	17,901	17,920
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	3,328	3,357	3,369	7,243	11,117	14,061	15,010	15,030
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	4,352	4,372	4,402	4,410	4,430
Imports-Max	1,666	2,042	1,186	997	1,070	5,974	7,682	5,346	5,362	5,861	6,382	9,289	10,202	12,435	12,794
Imports-Base	580	922	473	356	348	1,895	3,019	1,126	1,160	1,333	1,625	2,645	3,011	4,017	4,141
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,182	15,726	9,348	7,160	10,396	10,342	9,811	11,441	12,863	12,405	12,717	12,565
Exports-Base	9,123	8,952	11,297	13,978	13,184	6,225	4,278	7,872	7,820	7,152	8,029	7,823	8,111	7,118	6,937
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 116

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	5,227	2,638	2,871	2,931	2,704	2,911
Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,457	572	403	398	363	386
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,739	78	73	92	50	54
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,595	8,468	8,457	8,448
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	11,750	8,309	8,147	8,066	8,103
Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,634	16,230	15,713	14,088	13,549	13,774
Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,865	14,423	13,886	12,316	11,777	11,947
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,130	6,363	6,871	6,051	5,430	5,527
Oil CT-Max	9	15	14	14	5	6	7	6	6	5	8	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	2	1	1	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	1	0	1	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	459	460	459	285	285	285	202	201	198	201
Other-Min	840	792	775	679	625	417	418	402	277	276	273	194	196	193	193
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	502	477	469	452	606	403	619	663	679
Gas CT-Base	664	509	470	705	661	180	153	199	189	185	303	130	108	107	102
Gas CT-Min	192	145	94	84	81	53	38	78	77	57	100	74	54	53	55
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	21,466	24,648	25,670	25,328
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	4,333	7,243	11,117	13,095	13,083	13,102
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	3,389	7,263	9,232	10,192	10,212
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	3,408	3,437	4,410	4,430
Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,640	2,290	4,196	4,856	5,756	6,085
Imports-Base	580	922	473	356	270	535	489	99	104	181	357	733	914	1,228	1,293
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,823	13,375	13,239	14,157	14,116	13,965
Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,495	11,179	10,532	10,415	8,880	8,574
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 117

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,634	8,642	9,527	9,439	5,960	5,967	5,546	6,733	6,857	6,359	6,393	6,624
Coal-Base	10,193	7,181	7,514	8,821	7,851	3,456	3,416	2,987	3,023	2,713	3,304	3,144	2,825	2,855	2,969
Coal-Min	7,522	4,683	4,262	4,365	4,468	2,197	1,919	2,057	2,053	1,744	2,047	2,037	1,796	2,013	2,020
Nuclear-Max	14,053	13,576	14,013	13,576	13,047	8,152	3,676	-	-	-	-	-	-	-	-
Nuclear-Base	14,053	13,576	14,013	13,576	13,047	8,152	3,676	-	-	-	-	-	-	-	-
Nuclear-Min	14,053	13,535	13,676	13,370	12,750	8,036	3,507	-	-	-	-	-	-	-	-
Gas CC-Max	11,777	10,420	9,399	11,350	11,773	15,335	13,194	18,039	16,893	16,923	16,787	15,746	13,753	13,298	13,495
Gas CC-Base	9,677	8,975	8,305	9,996	10,016	12,666	11,071	16,480	15,220	15,020	15,441	14,741	13,190	12,390	12,471
Gas CC-Min	5,308	5,427	3,978	3,924	3,769	5,946	5,039	8,365	7,502	7,119	7,476	7,160	6,336	5,940	6,102
Oil CT-Max	9	15	14	14	5	14	11	19	20	19	18	-	-	-	-
Oil CT-Base	6	13	12	11	3	2	3	2	1	1	1	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
Other-Max	860	814	823	721	673	464	465	465	287	286	288	202	203	202	202
Other-Base	858	811	820	720	671	457	463	462	285	285	285	201	197	195	196
Other-Min	840	792	775	679	629	416	426	410	269	266	268	182	177	169	171
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	907	681	835	834	847	815	905	569	870	1,088	1,101
Gas CT-Base	664	509	470	705	670	190	262	329	302	275	391	220	193	151	154
Gas CT-Min	192	145	94	84	93	54	49	86	80	60	73	70	44	37	33
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	19,048	19,008	18,979	18,468	21,681	28,036	27,943	28,955	28,613
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	4,251	6,198	7,183	7,220	8,187	8,207	12,081	15,027	15,973	16,957
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	4,333	4,352	8,226	10,198	12,119	12,139
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	4,333	4,352	4,372	4,402	5,374	5,394
Imports-Max	1,666	2,042	1,186	997	1,070	5,974	8,137	7,478	7,653	7,993	7,492	7,854	8,955	10,193	10,540
Imports-Base	580	922	473	356	348	1,895	3,435	2,305	2,611	2,698	2,161	1,951	2,382	2,970	3,079
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,182	15,726	9,348	9,583	10,546	10,203	10,055	11,246	13,393	13,785	13,788	13,679
Exports-Base	9,123	8,952	11,297	13,978	13,184	6,225	4,221	5,517	5,288	4,864	5,499	7,852	7,780	7,123	6,872
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5

Annual Energy by Type (GWh)

Scenario 118

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,634	8,642	9,527	9,386	5,865	5,836	5,561	6,685	6,871	6,317	6,366	6,597
Coal-Base	10,193	7,181	7,514	8,821	7,851	3,456	3,276	2,837	2,878	2,599	3,138	2,926	2,625	2,709	2,829
Coal-Min	7,522	4,683	4,262	4,365	4,468	2,197	1,878	2,044	2,049	1,738	2,037	2,018	1,764	1,983	1,989
Nuclear-Max	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	5,373	4,918	5,388	4,918	5,373
Nuclear-Base	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	5,373	4,915	5,318	4,855	5,258
Nuclear-Min	14,053	13,535	13,676	13,370	12,750	8,036	5,210	4,759	5,105	4,754	5,130	4,706	5,091	4,690	5,086
Gas CC-Max	11,777	10,420	9,399	11,350	11,773	15,335	13,753	18,543	17,299	17,323	17,433	16,641	14,964	14,171	14,266
Gas CC-Base	9,677	8,975	8,305	9,996	10,016	12,666	11,054	16,332	15,032	14,917	15,226	14,576	13,016	12,286	12,331
Gas CC-Min	5,308	5,427	3,978	3,924	3,769	5,946	4,859	8,186	7,317	6,774	7,261	6,906	6,117	5,441	5,691
Oil CT-Max	9	15	14	14	5	14	20	16	16	16	15	-	-	-	-
Oil CT-Base	6	13	12	11	3	2	2	1	1	1	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
Other-Max	860	814	823	721	673	464	465	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	457	459	461	285	285	285	202	200	199	200
Other-Min	840	792	775	679	629	416	423	410	272	273	275	190	193	193	193
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	907	681	637	592	590	559	651	279	436	519	494
Gas CT-Base	664	509	470	705	670	190	166	207	196	190	269	119	108	92	89
Gas CT-Min	192	145	94	84	93	54	38	80	77	59	66	58	30	40	40
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	19,008	18,979	18,468	18,396	24,751	24,648	25,670	25,328
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	4,251	6,198	7,183	8,186	8,187	8,207	12,081	13,095	14,046	15,030
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	3,328	3,357	3,369	3,389	6,299	8,266	10,192	10,212
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	4,372	4,402	5,374	5,394
Imports-Max	1,666	2,042	1,186	997	1,070	5,974	7,682	4,928	4,840	5,313	4,615	4,752	5,296	6,544	6,474
Imports-Base	580	922	473	356	348	1,895	3,019	1,126	1,160	1,333	906	968	1,111	1,498	1,434
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,182	15,726	9,348	7,160	10,396	10,342	9,811	10,875	13,221	13,478	13,411	13,430
Exports-Base	9,123	8,952	11,297	13,978	13,184	6,225	4,278	7,872	7,820	7,152	8,151	9,414	9,538	8,442	8,360
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

	Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Coal-Max	11,494	8,192	8,380	9,634	8,535	9,225	9,124	5,799	5,799	5,388	6,653	6,879	6,377	6,595	6,817
	Coal-Base	10,193	7,181	7,514	8,821	7,789	3,339	3,155	2,809	2,832	2,560	3,099	2,910	2,619	2,792	2,897
	Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,878	2,048	2,046	1,740	2,033	2,019	1,766	1,983	1,989
	Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640	8,658	8,666	8,658	8,640
	Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640	8,658	8,657	8,640	8,631
	Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	11,939	8,396	8,319	8,387	8,359	8,152	8,182	8,314	8,323
	Gas CC-Max	11,777	10,420	9,399	11,350	11,462	14,522	13,085	18,010	16,895	16,987	17,067	16,446	14,960	14,136	14,387
	Gas CC-Base	9,677	8,975	8,305	9,996	9,776	12,309	10,772	16,101	14,861	14,713	15,085	14,575	13,076	12,740	12,845
	Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,874	8,267	7,329	6,907	7,289	6,880	6,101	5,589	5,673
	Oil CT-Max	9	15	14	14	5	6	7	10	12	10	10	-	-	-	-
S	Oil CT-Base	6	13	12	11	4	2	2	1	1	1	2	-	-	-	-
c	Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
e	Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
n	Other-Base	858	811	820	720	671	459	460	461	285	285	285	202	202	202	202
a	Other-Min	840	792	775	679	625	417	420	410	276	276	276	191	195	195	199
r	Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
i	Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
o	Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Gas CT-Max	883	695	607	916	881	581	526	545	557	521	624	211	223	230	239
1	Gas CT-Base	664	509	470	705	661	180	154	204	192	183	269	120	118	108	106
1	Gas CT-Min	192	145	94	84	81	53	39	76	75	56	64	59	31	41	41
9	Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	21,466	21,353	19,100	18,758
	Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	4,271	5,255	6,254	6,260	6,279	10,154	12,129	14,046	14,066
	Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	4,372	6,334	7,301	7,321
	Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	2,471	3,447	3,466
	Imports-Max	1,666	2,042	1,186	997	893	3,117	3,586	3,380	3,578	3,704	3,283	3,593	4,334	4,824	5,111
	Imports-Base	580	922	473	356	270	535	884	523	619	680	463	464	615	751	790
	Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Exports-Max	12,295	11,133	13,183	16,182	16,262	12,984	11,849	12,225	11,848	11,728	12,476	13,413	13,455	13,039	12,847
	Exports-Base	9,123	8,952	11,297	13,978	13,805	9,807	8,662	9,783	9,369	9,023	9,832	10,717	10,536	9,213	8,869
	Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Scenario 120

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	5,227	6,356	6,720	6,329	6,679	6,893
Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,457	2,942	2,793	2,570	2,791	2,904
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,739	2,037	2,001	1,743	1,968	1,975
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	13,559	13,233	13,679	13,270	13,678
Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,634	15,526	15,576	14,735	13,902	14,056
Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,865	14,099	14,010	13,047	12,975	13,047
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,130	4,873	5,021	5,043	5,478	5,592
Oil CT-Max	9	15	14	14	5	6	7	6	6	5	6	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	2	1	1	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	1	0	1	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	459	460	459	285	285	285	202	203	202	202
Other-Min	840	792	775	679	625	417	418	402	277	276	277	198	198	197	200
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	502	477	469	452	529	194	196	202	200
Gas CT-Base	664	509	470	705	661	180	153	199	189	185	259	116	119	121	116
Gas CT-Min	192	145	94	84	81	53	38	78	77	57	66	46	20	31	32
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	15,815	15,473
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	4,333	4,352	8,226	10,198	12,119	12,139
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	2,471	3,447	3,466
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	2,471	2,483	2,503
Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,640	1,210	1,570	1,912	2,196	2,155
Imports-Base	580	922	473	356	270	535	489	99	104	181	77	183	261	311	277
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,823	15,743	14,719	13,835	13,742	13,862
Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,495	13,640	12,769	11,743	10,215	10,212
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Scenario 121

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,634	8,642	9,527	9,439	5,960	5,967	5,546	2,709	2,981	2,965	2,725	2,913
Coal-Base	10,193	7,181	7,514	8,821	7,851	3,456	3,416	2,987	3,023	2,713	694	535	488	431	472
Coal-Min	7,522	4,683	4,262	4,365	4,468	2,197	1,919	2,057	2,053	1,744	106	100	126	95	102
Nuclear-Max	14,053	13,576	14,013	13,576	13,047	8,152	3,676	-	-	-	-	-	-	-	-
Nuclear-Base	14,053	13,576	14,013	13,576	13,047	8,152	3,676	-	-	-	-	-	-	-	-
Nuclear-Min	14,053	13,535	13,676	13,370	12,750	8,036	3,507	-	-	-	-	-	-	-	-
Gas CC-Max	11,777	10,420	9,399	11,350	11,773	15,335	13,738	18,880	17,705	17,655	17,264	16,103	13,997	13,176	13,392
Gas CC-Base	9,677	8,975	8,305	9,996	10,016	12,666	11,071	16,480	15,220	15,020	14,874	14,006	12,025	11,406	11,609
Gas CC-Min	5,308	5,427	3,978	3,924	3,769	5,946	5,039	8,365	7,502	7,119	7,509	7,246	6,490	6,123	6,307
Oil CT-Max	9	15	14	14	5	14	11	19	20	19	27	-	-	-	-
Oil CT-Base	6	13	12	11	3	2	3	2	1	1	1	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
Other-Max	860	814	823	721	673	464	465	465	287	286	288	202	203	202	202
Other-Base	858	811	820	720	671	457	463	462	285	285	284	197	192	190	191
Other-Min	840	792	775	679	629	416	426	410	269	266	262	181	178	171	173
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	907	681	835	834	847	815	1,084	1,073	1,355	1,485	1,502
Gas CT-Base	664	509	470	705	670	190	262	329	302	275	425	214	180	172	165
Gas CT-Min	192	145	94	84	93	54	49	86	80	60	143	96	104	98	92
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	19,048	19,008	18,979	18,468	21,681	28,036	27,943	28,955	28,613
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	4,251	6,198	7,183	7,220	8,187	11,097	14,972	15,993	17,901	17,920
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	4,333	7,243	11,117	14,061	15,010	15,030
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	4,333	4,352	4,372	4,402	4,410	4,430
Imports-Max	1,666	2,042	1,186	997	1,070	5,974	8,137	7,478	7,653	7,993	8,905	9,289	10,202	12,435	12,794
Imports-Base	580	922	473	356	348	1,895	3,435	2,305	2,611	2,698	2,769	2,645	3,011	4,017	4,141
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,182	15,726	9,348	9,395	9,176	8,878	8,636	9,507	12,863	12,694	12,928	12,824
Exports-Base	9,123	8,952	11,297	13,978	13,184	6,225	4,221	5,517	5,288	4,864	5,832	7,823	8,111	7,118	6,937
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 122

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,634	8,535	9,225	9,124	5,799	5,799	5,388	2,709	2,871	2,931	2,704	2,911
Coal-Base	10,193	7,181	7,514	8,821	7,789	3,339	3,155	2,809	2,832	2,560	604	403	398	363	386
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,878	2,048	2,046	1,740	78	73	92	50	54
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640	8,658	8,666	8,658	8,640
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640	8,595	8,468	8,457	8,448
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	11,939	8,396	8,319	8,387	8,250	8,309	8,147	8,066	8,103
Gas CC-Max	11,777	10,420	9,399	11,350	11,462	14,522	13,085	18,010	16,895	16,987	17,039	15,713	14,088	13,549	13,774
Gas CC-Base	9,677	8,975	8,305	9,996	9,776	12,309	10,772	16,101	14,861	14,713	14,891	13,886	12,316	11,777	11,947
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,874	8,267	7,329	6,907	7,217	6,871	6,051	5,430	5,527
Oil CT-Max	9	15	14	14	5	6	7	10	12	10	18	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	1	1	1	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	0	0	1	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	459	460	461	285	285	285	202	201	198	201
Other-Min	840	792	775	679	625	417	420	410	276	276	275	194	196	193	193
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	526	545	557	521	674	403	619	663	679
Gas CT-Base	664	509	470	705	661	180	154	204	192	183	310	130	108	107	102
Gas CT-Min	192	145	94	84	81	53	39	76	75	56	97	74	54	53	55
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	21,466	24,648	25,670	25,328
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	4,271	5,255	6,254	6,260	9,170	13,044	13,095	13,083	13,102
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	3,389	7,263	9,232	10,192	10,212
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	3,408	3,437	4,410	4,430
Imports-Max	1,666	2,042	1,186	997	893	3,117	3,586	3,380	3,578	3,704	3,900	4,196	4,856	5,756	6,085
Imports-Base	580	922	473	356	270	535	884	523	619	680	812	733	914	1,228	1,293
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,182	16,262	12,984	11,849	12,225	11,848	11,728	10,879	13,239	14,157	14,116	13,965
Exports-Base	9,123	8,952	11,297	13,978	13,805	9,807	8,662	9,783	9,369	9,023	8,496	10,532	10,415	8,880	8,574
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

	Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Coal-Max	11,494	8,192	8,380	9,634	8,642	9,527	9,386	5,865	5,836	5,561	2,669	2,973	2,846	2,572	2,775
	Coal-Base	10,193	7,181	7,514	8,821	7,851	3,456	3,276	2,837	2,878	2,599	567	393	394	352	379
	Coal-Min	7,522	4,683	4,262	4,365	4,468	2,197	1,878	2,053	2,055	1,743	92	89	106	69	73
	Nuclear-Max	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	5,373	4,918	5,388	4,918	5,373
	Nuclear-Base	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	5,364	4,852	5,140	4,753	5,134
	Nuclear-Min	14,053	13,535	13,676	13,370	12,750	8,036	5,210	4,759	5,105	4,754	5,029	4,655	4,956	4,612	4,963
	Gas CC-Max	11,777	10,420	9,399	11,350	11,773	15,335	13,753	18,543	17,299	17,323	16,835	15,783	13,516	12,908	13,064
	Gas CC-Base	9,677	8,975	8,305	9,996	10,016	12,666	11,054	16,332	15,032	14,917	14,626	13,775	11,704	11,130	11,292
	Gas CC-Min	5,308	5,427	3,978	3,924	3,769	5,946	4,859	8,269	7,290	6,813	7,205	6,899	6,036	5,490	5,712
	Oil CT-Max	9	15	14	14	5	14	20	16	16	16	14	-	-	-	-
S	Oil CT-Base	6	13	12	11	3	2	2	1	1	1	2	-	-	-	-
c	Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
e	Other-Max	860	814	823	721	673	464	465	465	287	286	287	202	203	202	202
n	Other-Base	858	811	820	720	671	457	459	461	285	285	284	197	198	194	198
a	Other-Min	840	792	775	679	629	416	423	412	272	273	274	187	192	187	192
r	Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
i	Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
o	Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Gas CT-Max	883	695	607	916	907	681	637	592	590	559	649	537	666	937	899
1	Gas CT-Base	664	509	470	705	670	190	166	207	196	190	287	121	103	100	94
2	Gas CT-Min	192	145	94	84	93	54	38	89	83	62	118	69	48	43	45
3	Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	19,008	18,979	18,468	21,681	24,751	24,648	22,385	22,043
	Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Solar-Max	1,730	1,853	2,154	2,266	2,308	4,251	6,198	7,183	8,186	8,187	11,097	13,044	14,061	15,973	15,993
	Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	3,328	3,357	3,369	6,279	9,190	12,129	13,083	13,102
	Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	2,471	2,483	2,503
	Imports-Max	1,666	2,042	1,186	997	1,070	5,974	7,682	5,346	5,362	5,861	6,385	7,042	7,646	10,087	10,001
	Imports-Base	580	922	473	356	348	1,895	3,019	1,126	1,160	1,333	1,262	1,422	1,546	2,246	2,174
	Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Exports-Max	12,295	11,133	13,183	16,182	15,726	9,348	7,160	10,396	10,342	9,811	11,136	13,244	13,705	12,994	13,019
	Exports-Base	9,123	8,952	11,297	13,978	13,184	6,225	4,278	7,872	7,820	7,152	8,189	9,226	9,684	8,107	8,036
	Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

	Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	5,227	2,616	2,912	2,836	2,659	2,877
	Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,457	566	390	381	366	387
	Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,739	79	67	86	49	51
	Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013
	Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013
	Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	13,559	13,086	13,506	13,278	13,695
	Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,634	15,972	15,668	14,177	14,098	14,299
	Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,865	14,342	13,967	12,504	12,220	12,397
	Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,130	5,897	5,574	5,519	5,477	5,637
	Oil CT-Max	9	15	14	14	5	6	7	6	6	5	8	-	-	-	-
S	Oil CT-Base	6	13	12	11	4	2	2	2	1	1	2	-	-	-	-
c	Oil CT-Min	6	4	3	2	1	0	0	0	1	0	1	-	-	-	-
e	Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
n	Other-Base	858	811	820	720	671	459	460	459	285	285	285	202	203	202	202
a	Other-Min	840	792	775	679	625	417	418	402	277	276	276	194	197	198	198
r	Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
i	Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
o	Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Gas CT-Max	883	695	607	916	881	581	502	477	469	452	599	220	276	243	242
1	Gas CT-Base	664	509	470	705	661	180	153	199	189	185	311	136	137	136	130
2	Gas CT-Min	192	145	94	84	81	53	38	78	77	57	99	74	47	61	62
4	Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	18,181	21,353	22,385	22,043
	Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	4,333	7,243	9,190	10,198	11,155	11,175
	Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	3,408	5,368	6,337	6,357
	Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	2,471	2,483	2,503
	Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,640	1,882	2,304	2,618	3,551	3,521
	Imports-Base	580	922	473	356	270	535	489	99	104	181	220	338	320	503	464
	Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,823	13,807	13,315	14,549	14,252	14,328
	Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,495	11,724	11,456	11,830	10,044	10,011
	Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 125

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,634	8,642	9,527	9,439	5,960	5,967	3,455	3,989	3,926	3,486	3,818	3,853
Coal-Base	10,193	7,181	7,514	8,821	7,851	3,456	3,416	2,987	3,023	2,128	2,553	2,448	2,158	2,246	2,321
Coal-Min	7,522	4,683	4,262	4,365	4,468	2,197	1,919	2,057	2,053	1,711	1,990	1,983	1,719	1,898	1,901
Nuclear-Max	14,053	13,576	14,013	13,576	13,047	8,152	3,676	-	-	-	-	-	-	-	-
Nuclear-Base	14,053	13,576	14,013	13,576	13,047	8,152	3,676	-	-	-	-	-	-	-	-
Nuclear-Min	14,053	13,535	13,676	13,370	12,750	8,036	3,507	-	-	-	-	-	-	-	-
Gas CC-Max	11,777	10,420	9,399	11,350	11,773	15,335	13,738	18,880	17,705	17,091	17,171	15,664	13,962	12,801	12,977
Gas CC-Base	9,677	8,975	8,305	9,996	10,016	12,666	11,071	16,480	15,220	14,561	14,897	13,657	12,009	11,126	11,254
Gas CC-Min	5,308	5,427	3,978	3,924	3,769	5,946	5,039	8,365	7,502	7,069	7,395	7,102	6,312	5,858	6,022
Oil CT-Max	9	15	14	14	5	14	11	19	20	17	15	-	-	-	-
Oil CT-Base	6	13	12	11	3	2	3	2	1	1	1	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
Other-Max	860	814	823	721	673	464	465	465	287	286	289	202	203	202	202
Other-Base	858	811	820	720	671	457	463	462	285	283	284	196	191	191	191
Other-Min	840	792	775	679	629	416	426	410	269	266	270	173	171	179	178
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	907	681	835	834	847	1,312	1,188	833	1,264	1,630	1,774
Gas CT-Base	664	509	470	705	670	190	262	329	302	522	623	375	356	311	322
Gas CT-Min	192	145	94	84	93	54	49	86	80	104	130	134	123	106	111
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	19,048	19,008	18,979	21,753	24,966	28,036	27,943	25,670	25,328
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	4,251	6,198	7,183	7,220	10,114	11,097	14,972	15,993	16,937	17,920
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	7,224	7,243	11,117	13,095	15,010	15,030
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	5,296	5,316	5,336	5,368	6,337	6,357
Imports-Max	1,666	2,042	1,186	997	1,070	5,974	8,137	7,478	7,653	7,485	7,042	7,349	8,369	9,624	9,976
Imports-Base	580	922	473	356	348	1,895	3,435	2,305	2,611	2,350	2,004	1,973	2,429	3,063	3,156
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,182	15,726	9,348	7,402	8,710	8,389	10,490	12,358	13,660	14,082	13,512	13,372
Exports-Base	9,123	8,952	11,297	13,978	13,184	6,225	4,221	5,517	5,288	6,587	7,135	8,847	8,608	7,824	7,590
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 126

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,634	8,535	9,225	9,124	5,799	5,799	3,456	3,983	3,998	3,507	3,940	3,963
Coal-Base	10,193	7,181	7,514	8,821	7,789	3,339	3,155	2,809	2,832	2,054	2,468	2,343	2,091	2,273	2,347
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,878	2,048	2,046	1,699	1,976	1,974	1,711	1,955	1,958
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640	8,658	8,666	8,658	8,640
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640	8,595	8,468	8,457	8,448
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	11,939	8,396	8,319	8,271	8,250	8,309	8,065	8,214	8,204
Gas CC-Max	11,777	10,420	9,399	11,350	11,462	14,522	13,085	18,010	16,895	16,624	16,647	14,901	13,310	12,584	12,782
Gas CC-Base	9,677	8,975	8,305	9,996	9,776	12,309	10,772	16,101	14,861	14,419	14,728	13,304	11,740	11,378	11,449
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,874	8,267	7,329	6,879	7,333	6,969	6,116	5,499	5,631
Oil CT-Max	9	15	14	14	5	6	7	10	12	16	15	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	1	1	2	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	0	1	1	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	288	202	203	202	202
Other-Base	858	811	820	720	671	459	460	461	285	285	285	202	199	200	201
Other-Min	840	792	775	679	625	417	420	410	276	275	276	193	190	194	194
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	526	545	557	691	767	468	539	472	492
Gas CT-Base	664	509	470	705	661	180	154	204	192	391	455	185	170	159	159
Gas CT-Min	192	145	94	84	81	53	39	76	75	79	95	103	86	72	75
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	21,466	21,353	22,385	22,043
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	4,271	5,255	6,254	8,187	9,170	13,044	13,095	13,083	13,102
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	3,369	3,389	7,263	9,232	10,192	10,212
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	3,408	3,437	4,410	4,430
Imports-Max	1,666	2,042	1,186	997	893	3,117	3,586	3,380	3,578	3,301	2,938	3,170	3,854	4,429	4,649
Imports-Base	580	922	473	356	270	535	884	523	619	660	505	495	667	830	899
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,182	16,262	12,984	11,849	12,225	11,848	11,777	12,302	14,111	14,055	14,567	14,377
Exports-Base	9,123	8,952	11,297	13,978	13,805	9,807	8,662	9,783	9,369	9,377	10,034	11,667	11,325	10,002	9,651
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 127

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,634	8,642	9,527	9,386	5,865	5,836	3,457	3,968	3,972	3,471	3,870	3,885
Coal-Base	10,193	7,181	7,514	8,821	7,851	3,456	3,276	2,837	2,878	2,059	2,473	2,327	2,064	2,219	2,296
Coal-Min	7,522	4,683	4,262	4,365	4,468	2,197	1,878	2,053	2,055	1,707	1,989	1,979	1,714	1,958	1,962
Nuclear-Max	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	5,373	4,918	5,388	4,918	5,373
Nuclear-Base	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	5,373	4,852	5,140	4,753	5,134
Nuclear-Min	14,053	13,535	13,676	13,370	12,750	8,036	5,210	4,759	5,105	4,641	4,958	4,655	5,020	4,658	5,018
Gas CC-Max	11,777	10,420	9,399	11,350	11,773	15,335	13,753	18,543	17,299	16,736	16,786	15,057	12,793	12,145	12,263
Gas CC-Base	9,677	8,975	8,305	9,996	10,016	12,666	11,054	16,332	15,032	14,495	14,728	13,235	11,133	10,748	10,814
Gas CC-Min	5,308	5,427	3,978	3,924	3,769	5,946	4,859	8,269	7,290	6,902	7,362	6,854	6,063	5,564	5,687
Oil CT-Max	9	15	14	14	5	14	20	16	16	21	18	-	-	-	-
Oil CT-Base	6	13	12	11	3	2	2	1	1	2	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
Other-Max	860	814	823	721	673	464	465	465	287	286	288	202	203	202	202
Other-Base	858	811	820	720	671	457	459	461	285	285	285	197	195	195	198
Other-Min	840	792	775	679	629	416	423	412	272	262	268	187	192	191	193
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	907	681	637	592	590	699	756	487	729	786	818
Gas CT-Base	664	509	470	705	670	190	166	207	196	386	444	181	184	168	172
Gas CT-Min	192	145	94	84	93	54	38	89	83	105	126	103	75	62	68
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	19,008	18,979	21,753	21,681	24,751	24,648	25,670	25,328
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	4,251	6,198	7,183	8,186	10,114	11,097	13,044	14,061	15,010	15,993
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	3,328	3,357	5,296	5,316	9,190	12,129	13,083	13,102
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	3,408	3,437	4,410	4,430
Imports-Max	1,666	2,042	1,186	997	1,070	5,974	7,682	5,346	5,362	5,824	5,029	5,259	5,834	6,959	6,983
Imports-Base	580	922	473	356	348	1,895	3,019	1,126	1,160	1,187	877	1,035	1,192	1,644	1,581
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,182	15,726	9,348	7,160	10,396	10,342	11,555	12,224	14,014	13,774	13,717	13,711
Exports-Base	9,123	8,952	11,297	13,978	13,184	6,225	4,278	7,872	7,820	8,166	9,022	10,273	10,462	9,000	8,893
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 128

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	3,447	3,988	4,012	3,504	3,974	3,973
Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,010	2,397	2,310	2,049	2,283	2,365
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,700	1,951	1,932	1,699	1,947	1,949
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	13,559	13,086	13,506	13,278	13,695
Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,441	15,327	14,750	13,287	13,497	13,566
Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,701	13,863	13,329	11,860	11,876	11,915
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,135	4,864	4,525	4,565	4,979	5,113
Oil CT-Max	9	15	14	14	5	6	7	6	6	8	7	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	2	1	2	3	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	1	1	1	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	459	460	459	285	285	285	202	203	202	202
Other-Min	840	792	775	679	625	417	418	402	277	276	279	194	197	197	199
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	502	477	469	653	711	294	326	412	431
Gas CT-Base	664	509	470	705	661	180	153	199	189	376	429	189	188	175	178
Gas CT-Min	192	145	94	84	81	53	38	78	77	81	96	53	71	58	57
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	18,181	18,059	19,100	18,758
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	7,224	7,243	11,117	11,164	11,155	11,175
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	3,408	5,368	6,337	6,357
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	3,437	4,410	4,430
Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,691	1,276	1,389	1,611	1,942	1,964
Imports-Base	580	922	473	356	270	535	489	99	104	240	130	212	223	311	278
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,212	15,014	14,243	14,421	14,201	14,189
Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,135	13,088	12,648	12,801	11,433	11,326
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 129

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,634	8,642	9,527	9,386	5,865	5,836	3,457	-	-	-	-	-
Coal-Base	10,193	7,181	7,514	8,821	7,851	3,456	3,276	2,837	2,878	2,059	-	-	-	-	-
Coal-Min	7,522	4,683	4,262	4,365	4,468	2,197	1,878	2,053	2,055	1,707	-	-	-	-	-
Nuclear-Max	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	3,676	-	-	-	-
Nuclear-Base	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	3,604	-	-	-	-
Nuclear-Min	14,053	13,535	13,676	13,370	12,750	8,036	5,210	4,759	5,105	4,641	3,336	-	-	-	-
Gas CC-Max	11,777	10,420	9,399	11,350	11,773	15,335	13,753	18,543	17,299	16,736	15,153	14,391	13,176	12,590	12,817
Gas CC-Base	9,677	8,975	8,305	9,996	10,016	12,666	11,054	16,332	15,032	14,495	14,240	13,451	12,190	11,593	11,746
Gas CC-Min	5,308	5,427	3,978	3,924	3,769	5,946	4,859	8,269	7,290	6,902	7,335	7,273	6,577	6,217	6,422
Oil CT-Max	9	15	14	14	5	14	20	16	16	21	8	-	-	-	-
Oil CT-Base	6	13	12	11	3	2	2	1	1	2	1	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
Other-Max	860	814	823	721	673	464	465	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	457	459	461	285	285	283	195	195	194	194
Other-Min	840	792	775	679	629	416	423	412	272	262	261	176	177	170	169
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	907	681	637	592	590	699	1,160	1,752	2,177	2,201	2,355
Gas CT-Base	664	509	470	705	670	190	166	207	196	386	858	561	628	573	594
Gas CT-Min	192	145	94	84	93	54	38	89	83	105	283	257	275	232	250
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	19,008	18,979	21,753	24,966	28,036	27,943	28,955	28,613
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	4,251	6,198	7,183	8,186	10,114	13,988	15,935	16,959	16,937	16,957
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	3,328	3,357	5,296	8,207	12,081	13,095	14,046	14,066
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	3,389	3,408	3,437	3,447	3,466
Imports-Max	1,666	2,042	1,186	997	1,070	5,974	7,682	5,346	5,362	5,824	6,887	9,899	10,820	13,148	13,488
Imports-Base	580	922	473	356	348	1,895	3,019	1,126	1,160	1,187	1,695	2,747	3,201	4,209	4,375
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,182	15,726	9,348	7,160	10,396	10,342	11,555	13,237	13,044	12,513	12,863	12,728
Exports-Base	9,123	8,952	11,297	13,978	13,184	6,225	4,278	7,872	7,820	8,166	8,342	8,004	7,685	6,748	6,539
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

	Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Scenario 130	Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	3,447	-	-	-	-	-
	Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,010	-	-	-	-	-
	Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,700	-	-	-	-	-
	Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640
	Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	12,295	8,398	8,261	8,073	8,083
	Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	11,518	8,152	8,066	7,979	7,982
	Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,441	14,917	13,771	12,658	12,418	12,537
	Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,701	13,295	12,210	10,603	9,734	9,888
	Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,135	5,856	6,906	6,082	5,492	5,620
	Oil CT-Max	9	15	14	14	5	6	7	6	6	8	7	-	-	-	-
	Oil CT-Base	6	13	12	11	4	2	2	2	1	2	2	-	-	-	-
	Oil CT-Min	6	4	3	2	1	0	0	0	1	1	0	-	-	-	-
	Other-Max	860	814	823	721	673	463	463	465	287	286	288	202	203	202	202
	Other-Base	858	811	820	720	671	459	460	459	285	285	284	200	198	193	194
	Other-Min	840	792	775	679	625	417	418	402	277	276	272	193	192	192	192
	Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Gas CT-Max	883	695	607	916	881	581	502	477	469	653	838	652	932	1,028	1,122
	Gas CT-Base	664	509	470	705	661	180	153	199	189	376	498	212	222	209	207
	Gas CT-Min	192	145	94	84	81	53	38	78	77	81	171	113	154	141	146
	Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	18,396	21,466	24,648	22,385	22,043
	Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	7,224	10,134	12,081	14,061	14,046	15,030
	Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	6,279	10,154	12,129	14,046	14,066
	Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	4,352	4,372	4,402	4,410	4,430
	Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,691	2,100	3,807	4,406	5,678	5,974
	Imports-Base	580	922	473	356	270	535	489	99	104	240	350	826	1,028	1,359	1,449
	Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,212	14,139	13,652	14,386	14,017	13,849
	Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,135	12,342	11,088	10,786	9,540	9,244
	Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 131

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,634	8,535	9,225	9,124	5,799	5,800	3,456	-	-	-	-	-
Coal-Base	10,193	7,181	7,514	8,821	7,789	3,339	3,155	2,809	2,832	2,054	-	-	-	-	-
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,878	2,048	2,046	1,699	-	-	-	-	-
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640	8,658	8,666	6,827	3,632
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,627	8,398	8,261	6,431	3,356
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	11,939	8,396	8,319	8,271	8,085	8,152	8,066	6,177	3,051
Gas CC-Max	11,777	10,420	9,399	11,350	11,462	14,522	13,085	18,008	16,895	16,624	15,906	14,156	13,106	12,795	12,441
Gas CC-Base	9,677	8,975	8,305	9,996	9,776	12,309	10,772	16,101	14,859	14,419	13,974	12,210	10,603	10,819	11,110
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,874	8,263	7,329	6,880	7,282	6,906	6,081	5,652	5,914
Oil CT-Max	9	15	14	14	5	6	7	10	12	16	14	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	1	1	2	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	0	1	0	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	459	460	461	285	285	284	200	198	197	194
Other-Min	840	792	775	679	625	417	420	410	276	275	271	193	192	190	179
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	526	545	557	691	899	661	933	1,329	2,003
Gas CT-Base	664	509	470	705	661	180	154	204	192	391	525	212	222	494	543
Gas CT-Min	192	145	94	84	81	53	39	76	75	79	176	113	155	164	206
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	18,396	21,466	24,648	22,385	25,328
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	4,271	5,255	6,254	8,187	12,061	12,081	14,061	15,010	17,920
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	3,369	6,279	10,154	12,129	13,083	14,066
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	4,352	4,372	4,402	4,410	5,394
Imports-Max	1,666	2,042	1,186	997	893	3,117	3,586	3,380	3,578	3,301	3,501	3,807	4,407	7,051	9,244
Imports-Base	580	922	473	356	270	535	884	523	619	660	748	826	1,028	1,711	2,904
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,182	16,262	12,984	11,849	12,224	11,848	11,777	11,871	13,652	14,386	12,737	13,040
Exports-Base	9,123	8,952	11,297	13,978	13,805	9,807	8,662	9,783	9,367	9,377	9,912	11,088	10,786	8,883	7,681
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 132

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	3,447	-	-	-	-	-
Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,010	-	-	-	-	-
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,700	-	-	-	-	-
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	11,744	9,005
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,564	13,867	11,418	8,673
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	13,559	13,233	13,553	11,066	7,951
Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,441	15,377	13,879	12,770	12,765	12,383
Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,701	13,775	12,469	10,961	10,587	10,944
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,135	5,895	6,105	6,009	5,459	5,663
Oil CT-Max	9	15	14	14	5	6	7	6	6	8	9	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	2	1	2	3	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	1	1	1	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	459	460	459	285	285	285	202	202	200	199
Other-Min	840	792	775	679	625	417	418	402	277	276	278	197	198	195	185
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	502	477	469	653	858	557	651	919	958
Gas CT-Base	664	509	470	705	661	180	153	199	189	376	537	213	188	395	492
Gas CT-Min	192	145	94	84	81	53	38	78	77	81	176	115	97	130	169
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	18,396	18,181	21,353	22,385	25,328
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	7,224	10,134	10,154	11,164	13,083	15,030
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	3,389	6,299	8,266	11,155	12,139
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	2,471	2,483	3,466
Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,691	1,879	2,295	2,583	4,744	6,326
Imports-Base	580	922	473	356	270	535	489	99	104	240	259	338	368	713	1,257
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,212	13,606	13,787	14,915	14,665	14,396
Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,135	11,793	12,362	12,497	10,749	9,371
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario	Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Scenario 133	Coal-Max	11,494	8,192	8,380	9,634	8,642	9,527	9,439	5,960	5,967	3,455	-	-	-	-	-
	Coal-Base	10,193	7,181	7,514	8,821	7,851	3,456	3,416	2,987	3,023	2,128	-	-	-	-	-
	Coal-Min	7,522	4,683	4,262	4,365	4,468	2,197	1,919	2,067	2,061	1,717	-	-	-	-	-
	Nuclear-Max	14,053	13,576	14,013	13,576	13,047	8,152	3,676	-	-	-	-	-	-	-	-
	Nuclear-Base	14,053	13,576	14,013	13,576	13,047	8,152	3,676	-	-	-	-	-	-	-	-
	Nuclear-Min	14,053	13,535	13,676	13,370	12,750	8,036	3,507	-	-	-	-	-	-	-	-
	Gas CC-Max	11,777	10,420	9,399	11,350	11,773	15,335	13,738	18,880	17,705	17,091	16,295	14,599	13,365	12,590	12,817
	Gas CC-Base	9,677	8,975	8,305	9,996	10,016	12,666	11,071	16,480	15,220	14,561	14,138	13,451	12,190	11,593	11,746
	Gas CC-Min	5,308	5,427	3,978	3,924	3,769	5,946	5,039	8,388	7,427	7,159	7,534	7,273	6,577	6,217	6,422
	Oil CT-Max	9	15	14	14	5	14	11	19	20	17	17	-	-	-	-
	Oil CT-Base	6	13	12	11	3	2	3	2	1	1	1	-	-	-	-
	Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
	Other-Max	860	814	823	721	673	464	465	465	287	286	286	202	203	202	202
	Other-Base	858	811	820	720	671	457	463	462	285	283	279	195	195	194	194
	Other-Min	840	792	775	679	629	416	426	411	269	266	265	176	177	170	169
	Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Gas CT-Max	883	695	607	916	907	681	835	834	847	1,312	2,035	1,752	2,177	2,201	2,355
	Gas CT-Base	664	509	470	705	670	190	262	329	302	522	695	561	628	573	594
	Gas CT-Min	192	145	94	84	93	54	49	98	90	124	287	257	275	232	250
	Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	19,048	19,008	18,979	21,753	24,966	28,036	27,943	28,955	28,613
	Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Solar-Max	1,730	1,853	2,154	2,266	2,308	4,251	7,162	9,110	9,152	12,042	14,952	15,935	16,959	17,901	17,920
	Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	7,224	10,134	12,081	13,095	14,046	14,066
	Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	3,308	3,328	3,357	3,369	3,389	3,408	3,437	3,447	3,466
	Imports-Max	1,666	2,042	1,186	997	1,070	5,974	8,137	8,049	8,307	8,584	9,510	9,899	10,820	13,148	13,488
	Imports-Base	580	922	473	356	348	1,895	3,435	2,305	2,611	2,350	2,725	2,747	3,201	4,209	4,375
	Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Exports-Max	12,295	11,133	13,183	16,182	15,726	9,348	7,151	8,356	8,034	10,490	11,717	13,044	12,513	12,863	12,728
	Exports-Base	9,123	8,952	11,297	13,978	13,184	6,225	4,221	5,517	5,288	6,587	7,310	8,004	7,685	6,748	6,539
	Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

	Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Scenario 134	Coal-Max	11,494	8,192	8,380	9,634	8,535	9,225	9,124	5,799	5,799	3,456	-	-	-	-	-
	Coal-Base	10,193	7,181	7,514	8,821	7,789	3,339	3,155	2,809	2,832	2,054	-	-	-	-	-
	Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,878	2,048	2,046	1,705	-	-	-	-	-
	Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,640	8,658	8,666	8,658	8,640
	Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	12,317	8,658	8,666	8,658	8,627	8,398	8,261	8,073	8,083
	Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	11,939	8,396	8,319	8,271	8,085	8,152	8,066	7,979	7,982
	Gas CC-Max	11,777	10,420	9,399	11,350	11,462	14,522	13,085	18,010	16,895	16,624	15,906	13,771	12,658	12,418	12,537
	Gas CC-Base	9,677	8,975	8,305	9,996	9,776	12,309	10,772	16,101	14,861	14,419	13,974	12,210	10,603	9,734	9,888
	Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,874	8,267	7,329	6,899	7,268	6,812	6,117	5,499	5,625
	Oil CT-Max	9	15	14	14	5	6	7	10	12	16	14	-	-	-	-
	Oil CT-Base	6	13	12	11	4	2	2	1	1	2	2	-	-	-	-
	Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
	Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
	Other-Base	858	811	820	720	671	459	460	461	285	285	284	200	198	193	194
	Other-Min	840	792	775	679	625	417	420	410	276	275	271	193	192	192	192
	Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
	Gas CT-Max	883	695	607	916	881	581	526	545	557	691	899	652	932	1,028	1,122
	Gas CT-Base	664	509	470	705	661	180	154	204	192	391	525	212	222	209	207
	Gas CT-Min	192	145	94	84	81	53	39	76	75	93	212	113	167	141	146
	Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	18,396	21,466	24,648	22,385	22,043
	Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
	Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	4,271	5,255	6,254	8,187	12,061	12,081	14,061	14,046	15,030
	Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	3,369	6,279	10,154	12,129	14,046	14,066
	Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	2,471	3,447	3,466
	Imports-Max	1,666	2,042	1,186	997	893	3,117	3,586	3,380	3,578	3,693	4,286	4,697	5,337	6,237	6,549
	Imports-Base	580	922	473	356	270	535	884	523	619	660	748	826	1,028	1,359	1,449
	Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Exports-Max	12,295	11,133	13,183	16,182	16,262	12,984	11,849	12,225	11,848	11,777	11,871	13,652	14,386	14,017	13,849
	Exports-Base	9,123	8,952	11,297	13,978	13,805	9,807	8,662	9,783	9,369	9,377	9,912	11,088	10,786	9,540	9,244
	Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 135

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,634	8,642	9,527	9,386	5,865	5,836	3,457	-	-	-	-	-
Coal-Base	10,193	7,181	7,514	8,821	7,851	3,456	3,276	2,837	2,878	2,059	-	-	-	-	-
Coal-Min	7,522	4,683	4,262	4,365	4,468	2,197	1,878	2,053	2,055	1,707	-	-	-	-	-
Nuclear-Max	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	5,373	4,918	5,388	4,918	5,373
Nuclear-Base	14,053	13,576	14,013	13,576	13,047	8,152	5,373	4,918	5,388	4,918	5,301	4,831	5,204	4,806	5,189
Nuclear-Min	14,053	13,535	13,676	13,370	12,750	8,036	5,210	4,759	5,105	4,641	4,958	4,601	4,849	4,305	4,666
Gas CC-Max	11,777	10,420	9,399	11,350	11,773	15,335	13,753	18,543	17,299	16,736	15,892	14,032	12,974	12,233	12,408
Gas CC-Base	9,677	8,975	8,305	9,996	10,016	12,666	11,054	16,332	15,032	14,495	13,866	13,233	12,026	11,492	11,625
Gas CC-Min	5,308	5,427	3,978	3,924	3,769	5,946	4,859	8,269	7,290	6,902	7,188	6,875	6,078	5,524	5,690
Oil CT-Max	9	15	14	14	5	14	20	16	16	21	12	-	-	-	-
Oil CT-Base	6	13	12	11	3	2	2	1	1	2	2	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	0	0	0	-	-	-	-
Other-Max	860	814	823	721	673	464	465	465	287	286	285	202	203	202	202
Other-Base	858	811	820	720	671	457	459	461	285	285	282	197	200	197	197
Other-Min	840	792	775	679	629	416	423	412	272	262	266	188	188	176	180
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	907	681	637	592	590	699	981	935	1,114	1,507	1,541
Gas CT-Base	664	509	470	705	670	190	166	207	196	386	517	447	566	510	522
Gas CT-Min	192	145	94	84	93	54	38	89	83	105	219	210	189	165	170
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	19,008	18,979	21,753	24,966	24,751	24,648	25,670	25,328
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	4,251	6,198	7,183	8,186	10,114	13,988	14,008	15,027	15,973	15,993
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	3,328	3,357	5,296	8,207	10,154	11,164	12,119	12,139
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	3,389	3,408	3,437	4,410	4,430
Imports-Max	1,666	2,042	1,186	997	1,070	5,974	7,682	5,346	5,362	5,824	5,816	6,443	6,985	8,542	8,559
Imports-Base	580	922	473	356	348	1,895	3,019	1,126	1,160	1,187	1,321	1,456	1,591	2,300	2,233
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,182	15,726	9,348	7,160	10,396	10,342	11,555	13,001	13,508	13,167	13,366	13,373
Exports-Base	9,123	8,952	11,297	13,978	13,184	6,225	4,278	7,872	7,820	8,166	8,941	9,489	9,360	7,832	7,720
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Department Attachment 5
Annual Energy by Type (GWh)

Scenario 136

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal-Max	11,494	8,192	8,380	9,635	8,534	9,225	8,998	5,508	5,530	3,447	-	-	-	-	-
Coal-Base	10,193	7,181	7,514	8,822	7,786	3,339	3,132	2,697	2,717	2,010	-	-	-	-	-
Coal-Min	7,522	4,683	4,262	4,365	4,222	2,189	1,876	2,045	2,045	1,700	-	-	-	-	-
Nuclear-Max	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013
Nuclear-Base	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,576	14,053	13,576	14,013	13,564	13,867	13,312	13,706
Nuclear-Min	14,053	13,535	13,676	13,370	13,730	13,370	13,587	13,203	13,493	13,196	13,559	13,233	13,553	13,084	13,450
Gas CC-Max	11,777	10,420	9,399	11,352	11,458	14,522	12,808	16,548	15,332	15,441	15,377	13,879	12,770	12,093	12,247
Gas CC-Base	9,677	8,975	8,305	9,998	9,770	12,311	10,607	15,090	13,838	13,701	13,775	12,469	10,962	10,278	10,380
Gas CC-Min	5,308	5,427	3,978	3,924	3,439	5,869	4,834	5,683	5,025	5,135	5,895	6,105	6,008	5,434	5,590
Oil CT-Max	9	15	14	14	5	6	7	6	6	8	9	-	-	-	-
Oil CT-Base	6	13	12	11	4	2	2	2	1	2	3	-	-	-	-
Oil CT-Min	6	4	3	2	1	0	0	0	1	1	1	-	-	-	-
Other-Max	860	814	823	721	673	463	463	465	287	286	287	202	203	202	202
Other-Base	858	811	820	720	671	459	460	459	285	285	285	202	202	200	201
Other-Min	840	792	775	679	625	417	418	402	277	276	278	197	198	198	198
Hydro-Max	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Base	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Hydro-Min	2,316	2,621	2,697	2,697	2,700	1,409	946	946	946	946	946	946	898	886	877
Gas CT-Max	883	695	607	916	881	581	502	477	469	653	858	557	651	600	613
Gas CT-Base	664	509	470	705	661	180	153	199	189	376	537	213	188	182	180
Gas CT-Min	192	145	94	84	81	53	38	78	77	81	176	115	97	74	77
Wind-Max	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	18,396	18,181	21,353	22,385	22,043
Wind-Base	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Wind-Min	12,187	15,133	16,701	16,171	15,974	15,846	15,763	15,723	15,685	15,183	15,111	14,896	14,764	12,530	12,188
Solar-Max	1,730	1,853	2,154	2,266	2,308	2,324	3,308	4,292	4,323	7,224	10,134	10,154	11,164	12,119	12,139
Solar-Base	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	3,389	6,299	8,266	10,192	10,212
Solar-Min	1,730	1,853	2,154	2,266	2,308	2,324	2,344	2,365	2,391	2,406	2,425	2,445	2,471	3,447	3,466
Imports-Max	1,666	2,042	1,186	997	893	3,117	2,771	1,431	1,412	1,691	1,879	2,294	2,583	3,141	3,108
Imports-Base	580	922	473	356	270	535	489	99	104	240	259	338	368	558	541
Imports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports-Max	12,295	11,133	13,183	16,184	16,257	12,983	12,968	15,227	15,185	14,212	13,606	13,787	14,915	14,785	14,747
Exports-Base	9,123	8,952	11,297	13,980	13,794	9,809	9,775	13,147	13,077	12,135	11,793	12,362	12,497	11,138	10,996
Exports-Min	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Docket No. E002/RP- 19-368

Attachment 6

EnCompass Discussion

1. Baseload Scenarios

Xcel's database has fifteen numbered datasets called "baseload scenarios." These baseload scenarios capture timing for retirements of the four baseload resources (King, Sherco unit 3, Monticello, and Prairie Island). Currently, King is scheduled to retire in 2038, Sherco unit 3 in 2035, Monticello in 2030, and Prairie Island units 1 and 2 are scheduled to retire in 2033 and 2034, respectively. Xcel's Base Case (Scenario 1) assumes these scheduled retirement dates, but baseload scenarios 2 to 15 examine three different potential retirement options for the resources: on-time, early, or extended. Xcel's fifteen baseload scenarios are shown in Table 1 below, along with the EnCompass datasets used to modify the base case.[1]

[1] For more detailed information on the baseload scenario datasets, see "Datasets" section below.

Table 1: Xcel's baseload scenarios by number, name, and dataset added

Baseload Scenario Number	Baseload scenario name and retirement timing, as deviating from base case	EnCompass Datasets Added
Scenario 1	Base Case--on time retirements for all four resources	NSP Reference Case Simplify
Scenario 2	Early King	Early King LBC 2
Scenario 3	Early Sherco unit 3	Early SH3 LBC 3
Scenario 4	Early King, Early Sherco unit 3	Early King Early SH3 LBC 4
Scenario 5	Early Monticello	Early Monti LBC 5
Scenario 6	Early Prairie Island	Early PI LBC 6
Scenario 7	Early Monticello, Early Prairie Island	Early Monti Early PI LBC 7
Scenario 8	Early King, Early Monticello, Early Prairie Island, Early Sherco unit 3	Early King Early Monti Early PI Early SH3 LBC 8
Scenario 9	Early King, Early Sherco unit 3, Extend Monticello	Early King Early SH3 Extend Monti LBC 9
Scenario 10	Early King, Extend Monticello	Early King Extend Monti LBC 10
Scenario 11	Early King, Early Sherco unit 3, Extend Prairie Island	Early King Early SH3 Extend PI LBC 11
Scenario 12	Early King, Early Sherco unit 3, Extend Monticello, Extend Prairie Island	Early King Early SH3 Extend Monti Extend PI LBC 12
Scenario 13	Extend Monticello	Extend Monti LBC 13
Scenario 14	Extend Prairie Island	Extend PI LBC 14
Scenario 15	Extend Monticello, Extend Prairie Island	Extend Monti Extend PI LBC 15

Xcel's fifteen baseload scenarios do not represent all possible combinations of retirements for these four baseload resources; there are actually 81 possible combinations of the three retirement timing options (early/on time/extended) for the four baseload plants in question. The Department examined 36 of the possible 81 baseload scenarios in Strategist, or an additional 21 baseload scenarios beyond those 15 submitted by Xcel. The remaining 45 potential baseload scenarios were examined by neither the Department nor the Company; these baseload scenarios were ones that extended the retirement dates of the coal plants.[2]

The following table shows total possible baseload scenarios (all combinations). Baseload scenarios examined by the Department are unshaded, scenarios examined by Xcel are numbered, and scenarios examined by neither the Department nor Xcel are shaded:

[2] The Department did not examine extended retirement dates for King and Sherco unit 3 for two primary reasons. First, burning coal for electricity generally runs counter to the State of Minnesota's clean energy goals; nonetheless, it's theoretically possible for carbon intensive resources to be considered financially prudent to operate. Second, coal plants have become some of the least cost-effective baseload plants to operate.

Table 2: Total possible baseload scenario combinations with Xcel's four resources and three retirement timings; unexamined scenarios shaded

	Early King, Early Sherco 3	Early King, On Time Sherco 3	Early King, Extend Sherco 3	On Time King, Early Sherco 3	On Time King, On Time Sherco 3	On Time King, Extend Sherco 3	Extend King, Early Sherco 3	Extend King, On Time Sherco 3	Extend King, Extend Sherco 3
Early Monticello, Early Prairie Island	8				7				
Early Monticello, On Time Prairie Island					5				
Early Monticello, Extend Prairie Island									
On Time Monticello, Early Prairie Island					6				
On Time Monticello, On Time Prairie Island	4	2		3	1 (Base)				
On Time Monticello, Extend Prairie Island	11				14				
Extend Monticello, Early Prairie Island									
Extend Monticello, On Time Prairie Island	9	10			13				
Extend Monticello, Extend Prairie Island	12				15				

Notably, Xcel did not examine any scenarios in which one nuclear plant was retired early while the other was extended. It happened that the Department's preferred baseload scenario ended up doing exactly that: retiring Monticello early and extending the retirement date of Prairie Island. Therefore, the Department's preferred scenario was not examined by Xcel in the Company's filing.

2. Contingencies

For each baseload scenario examined by Xcel, the Company also modeled a number of different contingencies (referred to by Xcel as "sensitivities"). In Xcel's analysis, baseload scenarios are solely dedicated to analyzing baseload retirement timings, while contingencies represent several other potential factors such as load forecast, externality and regulatory costs, gas prices, or various levels of demand-side resources. The following table shows the baseload contingencies—that is, contingencies examined in each of Xcel's fifteen baseload scenarios—along with each of the EnCompass datasets used to modify the base case.[3]

Table 3: Contingencies examined in each of Xcel's fifteen baseload scenarios by name, change made to each baseload scenario, and datasets added

Contingency	Change made to each baseload scenario (Scenarios 1-15)	EnCompass Datasets Added
PVRR (Present Value Revenue Requirement)	Sets EnCompass-generated externality costs to $0	Sens A – PVRR
Low Gas, Market	Lowers gas and oil distillate prices at various fuel delivery points; lowers MISO energy market price	Sens B – Low Gas, Market
High Gas, Market	Increases gas and oil distillate prices at various fuel delivery points; increases MISO energy market price	Sens C – High Gas, Market
Low Load	Lowers demand by increasing distributed generation, specifically DG solar and energy efficiency; actual load forecast is not changed	Sens D – Low Load
High Load	Increases NSP Monthly Peak, Energy and Load Shape Forecasts	Sens E – High Load
Low Resource Cost	Lowers fixed and variable costs of generic capital projects, both distributed and non-distributed	Sens F – Low Resource Cost
High Resource Cost	Increases fixed and variable costs of generic capital projects, both distributed and non-distributed	Sens G – High Resource Cost
Low Externality	Applies Commission approved externality values, no externalities are internalized into rates	Sens I – Low Externality

[3] For more detailed information on the contingency datasets, see "Datasets" section below.

Contingency	Change made to each baseload scenario (Scenarios 1-15)	EnCompass Datasets Added
Low Ext, Low Reg	Applies Commission approved values, some externalities internalized into rates, so also impacts market prices	Sens J – Low Ext, Low Reg
Mid Ext, Mid Reg	Applies Commission approved values, also impacts market prices	Sens K – Mid Ext, Mid Reg
High Externality	Applies Commission approved values, no externalities internalized into rates	Sens L – High Externality
No Ext, No Reg	Externality values set to zero, no externalities internalized into rates	Sens M – No Ext, No Reg
Markets Off	MISO maximum energy limit, reverse capacity limit, reverse energy limit all set to 0 (no market interactions)	Sens N - Markets Off
ND Plan	Changes to demand response resources and Community Solar Garden costs externality values set to zero, no externalities internalized into rates	ND Plan Sens M – No Ext, No Reg
High Distributed Solar Adoption (Futures Contingency; Sensitivity P)	Lowers demand by increasing distributed generation, specifically DG solar and energy efficiency; actual load forecast is not changed Lowers gas and oil distillate prices at various fuel delivery points; lowers MISO energy market price Lowers fixed and variable costs of generic capital projects, both distributed and non-distributed	Sens D - Low Load Sens B - Low Gas, Market Sens F - Low Resource Cost
High Electrification (Futures Contingency; Sensitivity Q)	Increases load with higher energy and demand forecasts Increases gas and oil distillate prices at various fuel delivery points; increases MISO energy market price Lowers fixed and variable costs of generic capital projects, both distributed and non-distributed	Sens E- High Load Sens C - High Gas Market, Sens F - Low Resource Cost

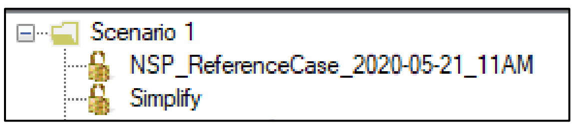
Contingency	Change made to each baseload scenario (Scenarios 1-15)	EnCompass Datasets Added
No Carbon Adder for Sales		Sens S – no carbon adder for sales
Hourly Carbon Retail Load		Sens U – Hourly Carbon Retail Load
Externalities in Dispatch		Sens V – Externalities in Dispatch
50 Percent Solar ELCC		Solar_ELCC-50PCT Sens A (PVRR run only)

Note that, as described in Xcel's Supplement, the Company examined an additional set of contingencies for its preferred plan (Scenario 9).

3. Datasets

Scenario 1, Xcel's base case, is modeled using two datasets: "NSP_ReferenceCase_2020-05-21_11AM" and "Simplify." In EnCompass, this is structured in the following manner:

Figure 1: Department screenshot of EnCompass scenario tree demonstrating Xcel's Scenario 1 with datasets



The NSP_ReferenceCase_2020-05-21_11AM dataset contains the bulk of the data associated with Xcel's database. This data can range from NSP load to MISO assumptions to the cost of coal to the depreciation of each plant; in short, every possible piece of data needed to model the base case can be found in this dataset. This means that the NSP_ReferenceCase_2020-05-21_11AM dataset also includes unnecessary data that doesn't get used and in effect slows down the model, which means the model takes longer to solve each run. To counter this, Xcel developed the "Simplify" dataset to remove unneeded/unused information and thus increase the speed of the run times.[4]

When Simplify dataset is added to EnCompass and nested under NSP_ReferenceCase_2020-05-21_11AM, as shown in Figure 1, the Simplify dataset over-writes some of the data in NSP_ReferenceCase_2020-05-21_11AM. Simplify does not contain the same amount of data as NSP_ReferenceCase_2020-05-21_11AM; rather, it contains only the targeted information that Xcel wishes to change in NSP_ReferenceCase_2020-05-21_11AM to help reduce the run times.
This over-writing of prior data is how all datasets work in EnCompass.

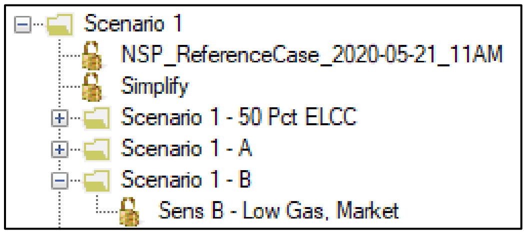
This means that the last dataset added will over-write any conflicting information that comes before it in a prior dataset. This also means that every other plan in Xcel's database is built upon these two datasets: all other baseload scenarios and contingencies are modeled by adding one or more additional

[4] In a call with the Department, Xcel stated that the "Simplify" dataset primarily removes ramp rates and the downtime of different facilities that do not have a material impact on the model's dispatch of the resources.

datasets, which then serve to modify the NSP_ReferenceCase_2020-05-21_11AM dataset.[5] This is the mechanism used by modelers when parties refer to "changes to the base case" or "modifications to the base scenario."

For example, Figure 2 below shows the structure of Xcel's Scenario 1 – B as it appears in EnCompass:

Figure 2: Department screenshot of EnCompass scenario tree demonstrating Xcel's Scenario 1 and Scenario 1-B with datasets



As shown in Figure 2, Scenario 1 – B uses three datasets:

- NSP_ReferenceCase_2020-05-21_11AM;
- Simplify; and
- Sens B – Low Gas, Market.

In this case, the Sens B – Low Gas, Market dataset lowers MISO energy prices as well as natural gas and oil distillate prices; therefore, the corresponding prices used in NSP_ReferenceCase_2020-05-21_11AM are overwritten in Scenario 1-B. The other folders (for example, "Scenario 1 – 50 Pct ELCC") contain datasets used in other runs.

Table 1 above shows the datasets used in EnCompass to model each of Xcel's baseload scenarios.[6] Since the Department, in Strategist, modeled an additional 21 baseload scenario combinations beyond those modeled by the Company, the Department used the Strategist version of many of the datasets shown in Table 1 along with new data sets to create the new scenarios. For example, Table 4 below shows the datasets that would be used to model the Department's preferred plan in EnCompass:

[5] Theoretically, Xcel's baseload scenario and contingency datasets could also over-write the Simplify dataset; however, the Department is unaware of instances where this might be the case.

[6] "LBC" stands for "Leave Behind Costs," and refers to the costs incurred by Xcel to shut down a plant. These costs are separate from decommissioning or depreciation costs, which occur before the plant is retired; rather, LBC costs begin to be incurred at the time of plant shutdown. As such, from a modeling point of view, they are typically a good indicator of plant retirements when looking at expansion plans. For each of Xcel's fifteen baseload scenarios, Xcel calculated a unique LBC dataset that reflects total baseload retirement leave-behind costs of a given scenario.

Table 4: Xcel datasets that would be used to model the Department's preferred plan

Department Preferred Plan	Datasets Associated with Department Preferred Plan
Early King Early Sherco unit 3 Early Monticello Extend Prairie Island	NSP_ReferenceCase_2020-05-21_11AM Simplify Early King Early SH3 Early Monti Extend PI LBC 2 LBC 3 LBC 5 LBC 14

To see the datasets used to model Xcel's baseload contingencies (as opposed to Xcel's preferred plan contingencies), see Table 3 above.

4. Expansion Plan versus Production Cost Runs

a. Expansion Plan Runs

When a modeling run is completed for a given scenario, one aspect of the results of the run is called an expansion plan, which refers to the specific combination of resource retirements or additions that occur over the planning period. Some of Xcel's scenarios generate expansion plans, while others use the pre-existing expansion plan of a "parent" scenario and simply re-dispatch resources within the construct of the expansion plan. These latter runs are generally used to better understand plan cost implications of an expansion plan. Therefore, Xcel groups its runs into two categories: "expansion plan runs" (also referred to as "optimized" runs) and "production cost runs."

In EnCompass, an expansion plan run takes up a lot of computer bandwidth; a single expansion plan involves solving a problem that has millions of different potential solutions. As a result, Xcel and the Department both found that expansion plan runs were best modeled with only a single run taking place on a given computer. Furthermore, to aid in reducing the size of an expansion plan problem, EnCompass uses simplified parameters when optimizing a run: rather than account for every hour of every day for every day of the year (referred to as an "8760" run), Encompass, as the inputs were constructed by Xcel, will only solve to the typical peak and off-peak days for each month of the full planning period.

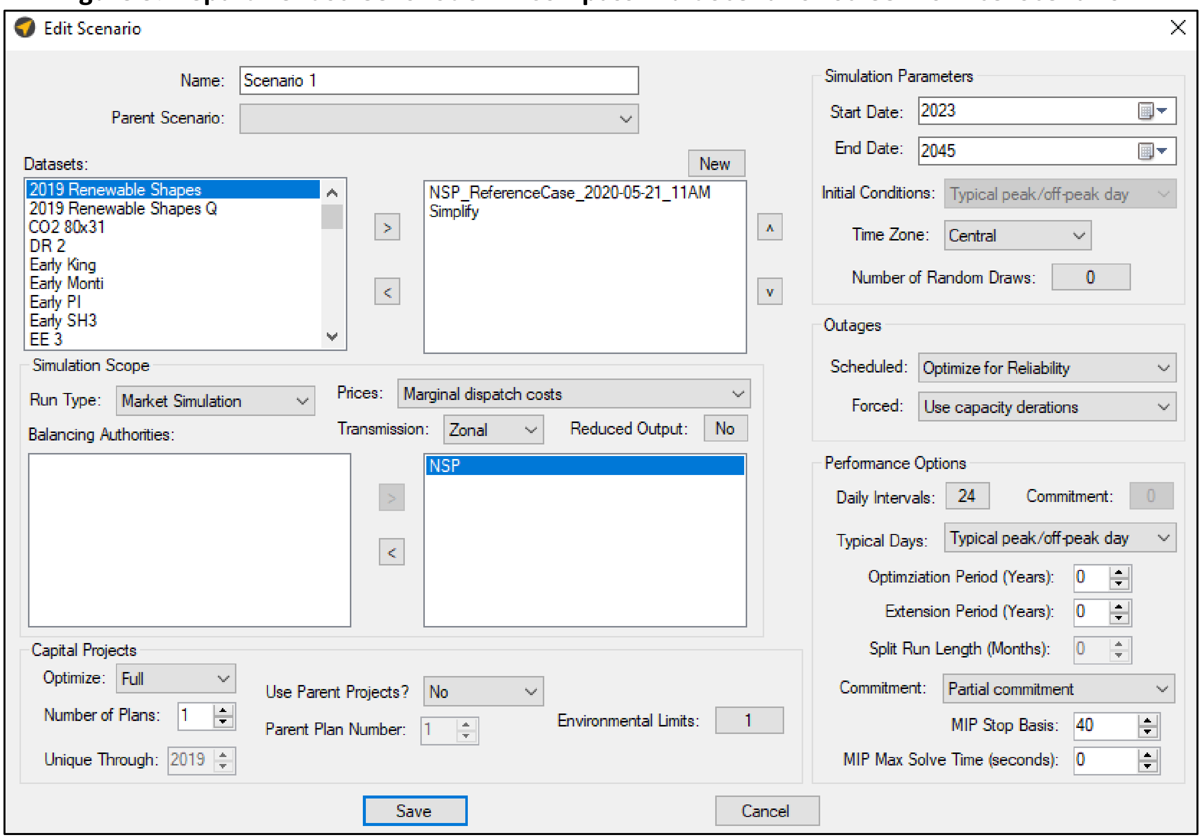
The Company found, however, that even with these simplified parameters, expansion plan runs were taking too long to solve.[7] To address this problem, the Company used an EnCompass feature called the "MIP stop basis" that trades model precision for run time (or vice versa).[8] Xcel found that its expansion

[7] This was described by Xcel in a call between the Department and the Company.

[8] EnCompass first determines the cost of an ideal expansion plan, adding fractions of units (partial-unit plan). The model then repeatedly tests varying plans that add full units (whole-unit plan). When EnCompass reaches a whole-unit plan whose cost is within a certain fraction of the cost of partial unit plan, the model stops. The fraction is determined by the modeler and is referred to as the MIP stop basis. Typically, the percentage Xcel used in its

plan runs typically required an MIP stop basis of 40, with some set at 50; by contrast, production cost runs typically required an MIP stop basis of 20.[9] This higher MIP stop basis indicates that Xcel's expansion plan runs are less precise than the Company's production cost runs. While these simplified and less precise parameters would not be desirable in a production cost run (more on this below), it is acceptable for an expansion plan run. This is because, beyond the expansion plan itself, the Company does not appear to use any of the data associated with an expansion plan run in other EnCompass runs.[10] Further, all CEMs have a trade-off between run time and accuracy. For example, in Strategist the greater the number of expansion unit alternatives available the longer a run will take.
Figure 3 below shows the run parameters for Xcel's base case (Scenario 1), which is an expansion plan run.[11]

Figure 3: Department screenshot of EnCompass "Edit Scenario" screen for Xcel Scenario 1



modeling is 40 basis points (or 0.4 percent) for expansion plan runs and 20 basis points (or 0.2 percent) for production cost runs. This means that two different expansion plan runs using the same exact set of inputs and data could produce outputs that are up to 0.4 percent different from one another. Put another way: it is possible that multiple plans are within the stop criteria.

[9] A MIP input of 40 indicates the cost of the actual plan must be within 0.4 percent of the cost of the ideal plan.

[10] For example, in an expansion plan run, Xcel uses data that shows an early Sherco 3 retirement or the addition of a generic combustion turbine in the 2030's; however, the Company does not appear to use the plan cost (or any other plan data).

[11] The Department notes a few points of interest in Figure 3. The right hand "Datasets" field shows the two datasets that define Scenario 1 (NSP_ReferenceCase_2020-05-021_11AM and Simplify) in the correct order; under "Capital Projects," the "Optimize" function is set to "Full" (indicating an expansion plan run); the simulation parameters have a start date of 2023 and an end date of 2045, and under "Performance Options," the "Typical Days" is set to "Typical peak/off-peak day."

As with Scenario 1, each of Xcel's baseload scenarios is modeled as an expansion plan run; that is, Scenario 1, Scenario 2, Scenario 3, …through Scenario 15.[12]

b. Production Cost Runs

Xcel's production cost runs are in some ways the inverse of the Company's expansion plan runs: these runs do not take up as much bandwidth to model (Xcel and the Department each found that they could comfortably run four production cost runs at the same time on a single computer), but production cost runs produce a very large amount of highly detailed information. These are the "8760" runs that solve to each hour of the day for every day of the year for each year of the planning period. Since Xcel's production cost runs do not generate their own expansion plans, but simply re-dispatch resources within a parent expansion plan, the 'parent' expansion plan run must be run and completed prior to modeling a 'child' production cost run.

Production cost runs can also be used to better understand information that was simplified in the expansion plan data. This means that the production cost run is more precise in the production cost routine, but this benefit comes at the cost of assuming as given the expansion plan. In any event, Xcel's production cost runs use an MIP stop basis of 20, trading run time for precision.[13] Figure 4 below shows the scenario assumptions for Xcel's Scenario 1-PVSC, which is a production cost run that uses the expansion plan of Scenario 1.[14][15]

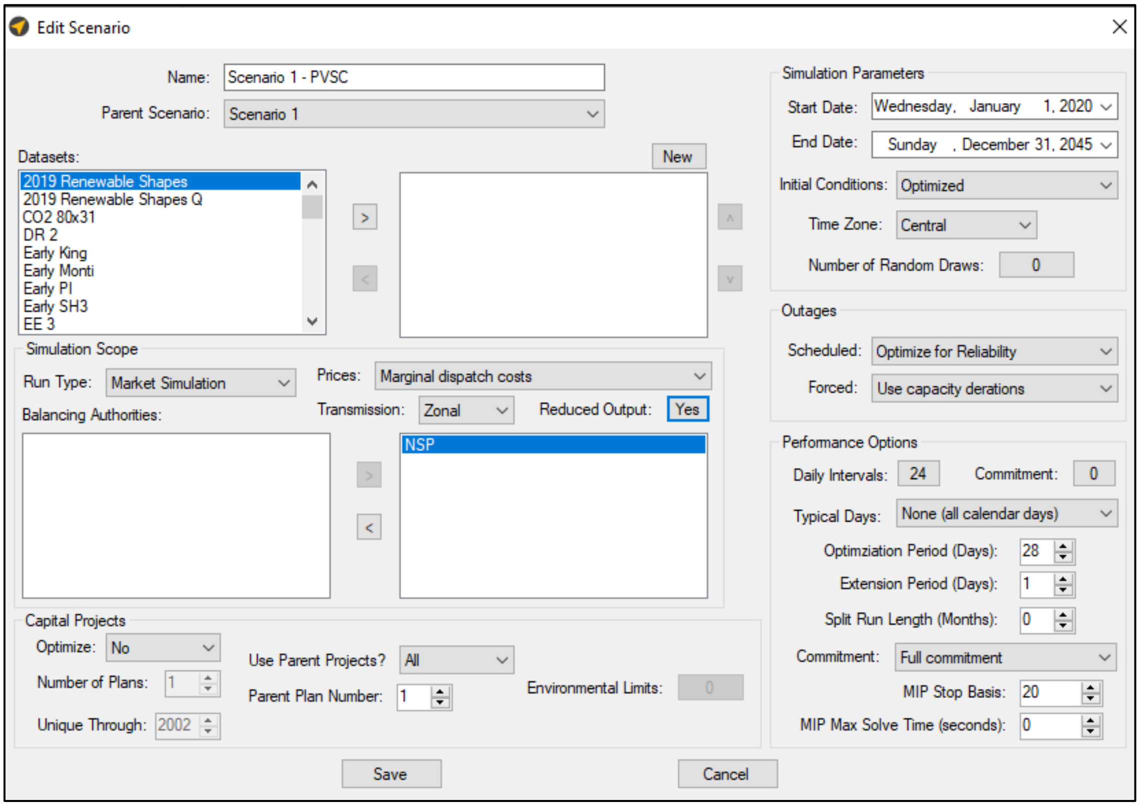
[12] Before modeling Scenarios 2-15, however, Scenario 1 must first be run and completed. While Scenarios 2-15 do not use the outputs of Scenario 1, they do use the inputs. Scenario 1 is the parent plan of Scenarios 2-15.

[13] Since production cost runs use a parent expansion plan run, the run time is much faster than a typical expansion plan run, so this tradeoff makes sense.

[14] Note that "Optimize" is set to "No" while "Use Parent Projects?" is set to "All" (meaning that the Scenario 1-PVSC production cost run does not generate an expansion plan and instead uses the expansion plan determined in the parent Scenario 1 run). Note also that that the MIP Stop basis is set to 20 and that performance options are set to "typical days: none (all calendar days)" and "Daily Intervals: 24" (meaning that the model solves for each of 24 hours for each day of the year).

[15] Each baseload scenario run (e.g., Scenario 1, Scenario 2, Scenario 3…Scenario 15) has an associated production cost run (e.g., Scenario 1-PVSC, Scenario 2-PVSC, Scenario 3-PVSC, …Scenario 15-PVSC). Prior to running a production cost run, the parent expansion plan run must first be modeled and completed.

Figure 4: Department screenshot of EnCompass "Edit Scenario" screen for Xcel Scenario 1-PVSC



The Department notes a few points of contrast between Figure 3 and Figure 4.

In the Scenario 1 expansion plan, no datasets appear in the upper right-hand quadrant for Scenario 1-PVSC. This is because Scenario 1-PVSC is a child scenario, and a child scenario will always use the *inputs* of the parent scenario (in this case, Scenario 1). Since the NSP_ReferenceCase_2020-05-021_11AM and Simplify datasets were used as inputs in Scenario 1, they are already built into Scenario 1-PVSC. Note however, that this is a different function from using the expansion plan, or the *outputs* of the parent scenario.[16] Therefore, while a child scenario always uses the inputs of a parent scenario, the modeler must specify whether the child scenario should use the outputs of a parent scenario as well.

Additionally, the Department notes that while Xcel's expansion plan runs begin in 2023, the production cost runs begin in 2020. This difference in start years is because Xcel expects no changes in the expansion plan to occur before 2023; that is, there should be no new units added or unknown retirements occurring from 2020 through 2022. However, since the planning period for the resource plan begins in 2020, Xcel still needed to calculate the cost of the plan for the whole planning period; thus, the production cost runs begin in 2020.

Third, in production cost run, there is a selection of Yes for "Reduced Output," unlike in the expansion plan run. This function does not alter the analysis, but restricts the amount of data produced from the

[16] The "Use Parent Projects?" function is specific to using the outputs of a parent scenario.

run; this may be needed to save space in the EnCompass database.[17] This function is discussed in the section of the Comments entitled "Department's Matching Analysis."

c. Contingencies

The final component to understanding Xcel's database is the treatment of contingencies. As described in the "Contingencies" section above, Xcel uses two sets of contingencies: those examined in each of the fifteen baseload scenarios (referred to by the Department as "baseload contingencies" and listed in Table 3 above), and those examined solely in Xcel's preferred plan, Scenario 9 (referred to by the Department as Scenario 9 contingencies).[18] The following discussion pertains to Xcel's baseload contingencies.

In Xcel's database, some baseload contingencies are modeled as solely as production cost runs while other are modeled both as expansion plan and production cost runs. Scenario 1-B (which uses the Low Gas, Spot Market contingency) is an example of the former while Scenarios 1-E and 1-E-PVSC (which use the High Load contingency) is an example of the latter.

Figure 5 shows how Scenario 1-B and 1-E are structured in EnCompass's scenario tree.

Figure 5: Department screenshot of EnCompass scenario tree demonstrating Xcel's Scenario 1-B versus Scenario 1-E

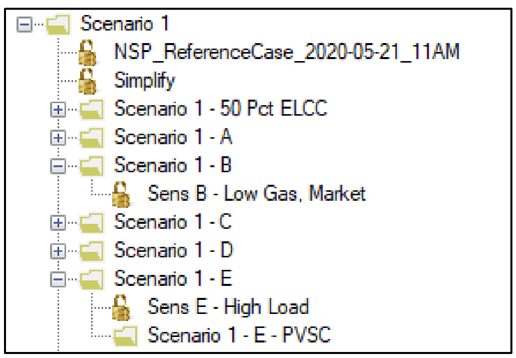


Figure 5 shows that Scenario 1 is the parent to Scenario 1-B. This means that since Scenario 1-B is a production cost run, it uses the Scenario 1 expansion plan.[19]

[17] As submitted to the Department by Xcel, the Scenario 1-PVSC run did not suppress outputs, but the Department made this change. It may or may not be necessary for Xcel to save space in its EnCompass's databases, but it is necessary for the Department. This is because, while Xcel uses a "network" version of EnCompass, the Department uses a "desktop" version of EnCompass. In the desktop version, each database has a maximum capacity of 10 GB, which can be completely used up from a single production cost run.
[18] Matrices of all runs Xcel performed in EnCompass can be found in Attachment A to these Comments.
[19] In EnCompass, this is done by setting "Optimize" to "No" and "Use Parent Projects?" to "All," the same settings shown in the Scenario 1-PVSC example above.

Scenario 1 is also the parent to Scenario 1-E. Scenario 1-E is a new expansion plan run and, while it uses the same inputs as Scenario 1, it does not use the expansion plan outputs; instead, Scenario 1-E generates an entirely new expansion plan.[20]

Both Scenario 1 and Scenario 1-E are parents to Scenario 1-E-PVSC. Scenario 1-E-PVSC is a production cost run that uses the expansion plan established in Scenario 1-E. Since Scenario 1-E does not use the Scenario 1 expansion plan, Scenario 1-E-PVSC does not use the Scenario 1 expansion plan either.[21]

The following table shows all child scenarios for which Scenario 1 is a parent plan and indicates whether the given child scenario is an expansion plan or production cost run. The contingencies associated with each of these scenarios are also examined in each of the other baseload scenarios.

[20] Scenario 1-E sets the "Optimize" function to "Full" and the "Use Parent Projects?" option to "No," the same settings shown in the Scenario 1 example above. Unlike Scenario 1, however, Scenario 1-E has a parent scenario.

[21] Scenario 1-E-PVSC sets the "Optimize" function to "No" and "Use Parent Projects?" to "All," the same settings shown in the Scenario 1-B. This means that Scenario 1-E-PVSC uses the expansion plan of Scenario 1-E. However, since Scenario 1-E sets the "Use Parent Projects?" option to "No," the chain stops there. The Scenario 1 expansion plan does not inform Scenario 1-E-PVSC.

Table 5: Scenario 1 child scenarios, identified by type of run

Scenario	**Expansion Plan Run**	**Production Cost Run**
Scenario 1-A*		x
Scenario 1-B		x
Scenario 1-C		x
Scenario 1-D	x	
Scenario 1-D-PVSC		x
Scenario 1-E	x	
Scenario 1-E-PVSC		x
Scenario 1-F		x
Scenario 1-G		x
Scenario 1-I		x
Scenario 1-J		x
Scenario 1-L		x
Scenario 1-M		x
Scenario 1-N		x
Scenario 1-ND Plan*	x	
Scenario 1-ND Plan- PVSC		x
Scenario 1-P	x	
Scenario 1-P-PVSC		x
Scenario 1-Q	x	
Scenario 1-Q-PVSC		x
Scenario 1-S: No Carbon Adder for Sales	x	
Scenario 1-S-PVSC		x
Scenario 1-U: Hourly Carbon Retail Load	x	
Scenario 1-U-PVSC		x
Scenario 1-V: Externalities in Dispatch	x	
Scenario 1-V-PVSC		x
Scenario 1-50 Percent Solar ELCC	x	
Scenario 1-50 Percent Solar ELCC*		x

**These Scenarios look at PVRR instead of PVSC but are still considered Production Cost Runs.*

5. Externality and Regulatory Costs

Many of Xcel's contingencies involve varied levels of externality and regulatory costs; this section exists to help the reader understand how these cost streams are captured.

When a power plant operates, it produces emissions (CO, CO_2, NO_X, SO_X, etc.). To calculate the total externality cost associated with these emissions, the analyst:

- Determines the amount of energy produced by the plant over a given period of time (MWh/year)
- Determines the release rate of each type of emission at that specific plant (this can be in tons/MWh or tons/MMBTU [for the fuel] and MMBTU/MWh [for the generator])
- Determines the "tax" rate for each type of emission ($/ton)
- Multiplies the release rate by the tax rate for each type of emission to obtain the externality rate ($/MWh)
- Multiplies the plant's energy produced in a given time (MWh/year) by the externality rate ($/MWh) of each type of emission to obtain the externality cost associated with each emission ($/year)
- Sums the results to get total externality costs ($/year)[22]

Externality costs are typically reported in nominal dollars, but they are not actually built into any electricity prices or rates. They simply represent the cost of societal ills associated with the emissions; nobody pays for them with money.

When externality costs get bundled into the price of electricity (or *internalized*), they are referred to as internalized costs, internalized externality costs, or, in the case of Xcel's IRP, "regulatory costs." Unlike externality costs, regulatory costs are actual costs that *do* get paid for with money.[23]

When regulatory costs are present, the price to generate energy at a specific plant or resource is dependent upon emissions production at that plant or resource. Since utilities choose to run and dispatch resources based on price, and since the MISO marketplace facilitates purchases and sales based on price, the inclusion of regulatory costs impacts both utility choices and market outcomes.

The Minnesota Legislature directed the Minnesota Commission to develop externality and regulatory (internal) costs. The Commission produced an order that calculated CO_2 internal costs based on the assumption that Congress implements some type of nationwide emissions tax on generators starting in 2025. In other words, the Commission envisioned a theoretical future in which some externality costs are internalized in rates; however, it's also possible that this does not happen. Therefore, starting in 2025, there are two potential futures of the treatment of CO_2 externality and regulatory costs: either there is no emissions tax and the externality costs associated with emissions remain 100% externality costs, or *some* externality costs remain externality costs (non-CO_2) and *some* externality costs (CO_2) are internalized in rates and become regulatory costs.

In resource planning, the externality costs associated with the emissions from all of a utility's resources remain externality costs and will not affect the dispatch order or the Present Value Revenue Requirement (PVRR). It *will* affect the Present Value Social Cost (PVSC), since PVSC is equal to PVRR +

[22] In Strategist, this cost is tracked separately from the internal costs and reported as part of societal costs but not revenue requirements. At this time, the Department is unclear how this cost is tracked in EnCompass.
[23] Note that while there are currently no CO_2 internal costs in rates, there may be some costs for SO_x and NO_x allowances built into rates.

externalities. Therefore, if 100% of the externality cost remains externality cost in 2025, the only thing to be determined is the externality rates: for example, should they be high, middle, or low? In EnCompass, Xcel captures these two options in the contingencies "Low Externality" (Sens I dataset) and "High Externality" (Sens L dataset). Xcel also examined a contingency "Externalities in dispatch" (Sens V dataset); this name suggests that it would assume 100% of externality costs remain categorized as such, but that these externality costs do impact dispatch order.

If Congress decides to enact some type of emissions tax, *some but not all* externality costs associated with emissions are internalized as regulatory costs (limited to CO_2 in the PUC's order); the remaining externality costs (all except CO_2) continue to be considered externality costs. In EnCompass, Xcel captures various options in the contingencies "No Externality, No Regulatory" (Sens M dataset), "Low Externality, Low Regulatory" (Sens J dataset), and "Mid Externality, Mid Regulatory" (Sens K dataset).

Docket No. E002/RP- 19-368

Attachment 7

EnCompass Matching Results

EnCompass Matching Results

Scenario	Expansion Plan Runs (2023-2045)	MIP Stop Basis	Value
Scenario 1	Scenario 1 - Base	40	$ 28,499,086
Scenario 1 - DW	Scenario 1 - Base - DW	40	$ 28,531,223
	Delta		$ 32,137
	%Change		0.11%
Scenario 2	Scenario 2 - Early King	40	$ 28,605,346
Scenario 2 - DW	Scenario 2 - Early King - DW	40	$ 28,605,251
	Delta		$ (96)
	%Change		0.00%
Scenario 3	Scenario 3 - Early SH3	40	$ 28,544,509
Scenario 3 - DW	Scenario 3 - Early SH3 - DW	40	$ 28,549,251
	Delta		$ 4,743
	%Change		0.02%
Scenario 4	Scenario 4 - Early Coal	40	$ 28,645,082
Scenario 4 - DW	Scenario 4 - Early Coal - DW	40	$ 28,599,537
	Delta		$ (45,545)
	%Change		-0.16%
Scenario 5	Scenario 5 - Early Monti	40	$ 28,707,694
Scenario 5 - DW	Scenario 5 - Early Monti - DW	40	$ 28,697,697
	Delta		$ (9,996)
	%Change		-0.03%
Scenario 6	Scenario 6 - Early PI	40	$ 29,416,869
Scenario 6 - DW	Scenario 6 - Early PI - DW	40	$ 29,458,905
	Delta		$ 42,036
	%Change		0.14%
Scenario 7	Scenario 7 - Early Nuclear	40	$ 29,543,505
Scenario 7 - DW	Scenario 7 - Early Nuclear - DW	40	$ 29,540,665
	Delta		$ (2,839)
	%Change		-0.01%
Scenario 8	Scenario 8 - Early Baseload	40	$ 29,650,556
Scenario 8 - DW	Scenario 8 - Early Baseload - DW	45	$ 29,711,983
	Delta		$ 61,426
	%Change		0.21%
Scenario 9	Scenario 9 - Early Coal; Extend Monti	40	$ 28,319,802
Scenario 9 - DW	Scenario 9 - Early Coal; Extend Monti - DW	40	$ 28,327,002
	Delta		$ 7,201
	%Change		0.03%
Scenario 10	Scenario 10 - Early King; Extend Monti	40	$ 28,298,720
Scenario 10 - DW	Scenario 10 - Early King; Extend Monti - DW	40	$ 28,296,626
	Delta		$ (2,095)
	%Change		-0.01%
Scenario 11	Scenario 11 - Early Coal; Extend PI	40	$ 27,901,330
Scenario 11 - DW	Scenario 11 - Early Coal; Extend PI - DW	40	$ 27,930,431
	Delta		$ 29,102
	%Change		0.10%

Scenario	Expansion Plan Runs (2023-2045)	MIP Stop Basis	Value
Scenario 12	Scenario 12 - Early Coal; Extend All Nuclear	40	$ 27,661,844
Scenario 12 - DW	Scenario 12 - Early Coal; Extend All Nuclear - DW	40	$ 27,663,007
	Delta		$ 1,163
	%Change		0.00%
Scenario 13	Scenario 13 - Extend Monti	40	$ 28,193,895
Scenario 13 - DW	Scenario 13 - Extend Monti - DW	40	$ 28,225,361
	Delta		$ 31,466
	%Change		0.11%
Scenario 14	Scenario 14 - Extend PI	40	$ 27,751,271
Scenario 14 - DW	Scenario 14 - Extend PI - DW	40	$ 27,743,821
	Delta		$ (7,450)
	%Change		-0.03%
Scenario 15	Scenario 15 - Extend All Nuclear	40	$ 27,521,958
Scenario 15 - DW	Scenario 15 - Extend All Nuclear - DW	43	$ 27,496,665
	Delta		$ (25,294)
	%Change		-0.09%

Scenario	PVSC Production Cost Runs (2020-'45)	MIP Stop Basis	Value
Scenario 1 - PVSC	Scenario 1 - Base - PVSC	20	$ 28,553,773
Scenario 1 - PVSC - DW	Scenario 1 - Base - PVSC - DW	20	$ 28,882,073
	Delta		$ (328,300)
	%Change		1.15%
Scenario 2 - PVSC	Scenario 2 - Early King - PVSC	20	$ 28,637,067
Scenario 2 - PVSC - DW	Scenario 2 - Early King - PVSC - DW	20	$ 28,934,874
	Delta		$ (297,807)
	%Change		1.04%
Scenario 3 - PVSC	Scenario 3 - Early SH3 - PVSC	20	$ 28,601,000
Scenario 3 - PVSC - DW	Scenario 3 - Early SH3 - PVSC - DW	20	$ 28,899,557
	Delta		$ (298,557)
	%Change		1.04%
Scenario 4 - PVSC	Scenario 4 - Early Coal - PVSC	20	$ 28,673,400
Scenario 4 - PVSC - DW	Scenario 4 - Early Coal - PVSC - DW	20	$ 28,933,397
	Delta		$ (259,997)
	%Change		0.91%
Scenario 5 - PVSC	Scenario 5 - Early Monti - PVSC	20	$ 28,735,098
Scenario 5 - PVSC - DW	Scenario 5 - Early Monti - PVSC - DW	20	$ 29,027,138
	Delta		$ (292,041)
	%Change		1.02%
Scenario 6 - PVSC	Scenario 6 - Early PI - PVSC	20	$ 29,331,115
Scenario 6 - PVSC - DW	Scenario 6 - Early PI - PVSC - DW	20	$ 29,670,185
	Delta		$ (339,070)
	%Change		1.16%
Scenario 7 - PVSC	Scenario 7 - Early Nuclear - PVSC	20	$ 29,429,800
Scenario 7 - PVSC - DW	Scenario 7 - Early Nuclear - PVSC - DW	20	$ 29,732,800
	Delta		$ (303,000)
	%Change		1.03%
Scenario 8 - PVSC	Scenario 8 - Early Baseload - PVSC	20	$ 29,529,190
Scenario 8 - PVSC - DW	Scenario 8 - Early Baseload - PVSC - DW	20	$ 29,870,297
	Delta		$ (341,108)
	%Change		1.16%
Scenario 9 - PVSC	Scenario 9 - Early Coal; Extend Monti - PVSC	20	$ 28,385,792
Scenario 9 - PVSC - DW	Scenario 9 - Early Coal; Extend Monti - PVSC - DW	20	$ 28,689,079
	Delta		$ (303,287)
	%Change		1.07%
Scenario 10 - PVSC	Scenario 10 - Early King; Extend Monti - PVSC	20	$ 28,360,993
Scenario 10 - PVSC - DW	Scenario 10 - Early King; Extend Monti - PVSC - DW	20	$ 28,656,159
	Delta		$ (295,165)
	%Change		1.04%
Scenario 11 - PVSC	Scenario 11 - Early Coal; Extend PI - PVSC	20	$ 28,022,446
Scenario 11 - PVSC - DW	Scenario 11 - Early Coal; Extend PI - PVSC - DW	20	$ 28,347,914
	Delta		$ (325,468)
	%Change		1.16%

Scenario	PVSC Production Cost Runs (2020-'45)	MIP Stop Basis	Value
Scenario 12 - PVSC	Scenario 12 - Early Coal; Extend All Nuclear - PVSC	20	$ 27,805,328
Scenario 12 - PVSC - DW	Scenario 12 - Early Coal; Extend All Nuclear - PVSC - DW	20	$ 28,104,730
	Delta		$ (299,403)
	%Change		1.08%
Scenario 13 - PVSC	Scenario 13 - Extend Monti - PVSC	20	$ 28,276,855
Scenario 13 - PVSC - DW	Scenario 13 - Extend Monti - PVSC - DW	20	$ 28,599,350
	Delta		$ (322,495)
	%Change		1.14%
Scenario 14 - PVSC	Scenario 14 - Extend PI - PVSC	20	$ 27,895,750
Scenario 14 - PVSC - DW	Scenario 14 - Extend PI - PVSC - DW	20	$ 28,189,603
	Delta		$ (293,853)
	%Change		1.05%
Scenario 15 - PVSC	Scenario 15 - Extend All Nuclear - PVSC	20	$ 27,682,982
Scenario 15 - PVSC - DW	Scenario 15 - Extend All Nuclear - PVSC - DW	20	$ 27,961,341
	Delta		$ (278,359)
	%Change		1.01%

Scenario	RunID	Company	Year	Operating Cost	Carrying Costs
Scenario 1	0	NSP	0	$ 28,322,956.04	$ 176,129.97
Scenario 1	0	NSP	2023	$ 1,712,901.17	
Scenario 1	0	NSP	2024	$ 1,757,969.14	
Scenario 1	0	NSP	2025	$ 1,803,960.20	
Scenario 1	0	NSP	2026	$ 1,789,399.58	
Scenario 1	0	NSP	2027	$ 1,903,987.31	
Scenario 1	0	NSP	2028	$ 1,918,827.09	
Scenario 1	0	NSP	2029	$ 1,940,596.79	
Scenario 1	0	NSP	2030	$ 2,020,549.26	$ 7,830.58
Scenario 1	0	NSP	2031	$ 2,048,275.59	$ 7,987.19
Scenario 1	0	NSP	2032	$ 2,140,473.81	$ 8,146.93
Scenario 1	0	NSP	2033	$ 2,336,825.09	$ 16,619.74
Scenario 1	0	NSP	2034	$ 2,423,933.80	$ 25,428.21
Scenario 1	0	NSP	2035	$ 2,408,887.39	$ 30,234.81
Scenario 1	0	NSP	2036	$ 2,526,788.43	$ 30,839.51
Scenario 1	0	NSP	2037	$ 2,619,495.39	$ 31,456.30
Scenario 1	0	NSP	2038	$ 2,767,197.24	$ 36,646.54
Scenario 1	0	NSP	2039	$ 2,850,203.26	$ 37,379.48
Scenario 1	0	NSP	2040	$ 3,021,029.42	$ 38,127.07
Scenario 1	0	NSP	2041	$ 3,187,895.06	$ 38,889.60
Scenario 1	0	NSP	2042	$ 3,340,083.17	$ 39,667.40
Scenario 1	0	NSP	2043	$ 3,471,307.46	$ 40,460.74
Scenario 1	0	NSP	2044	$ 3,549,735.16	$ 41,269.96
Scenario 1	0	NSP	2045	$ 3,776,186.05	$ 42,095.36
Scenario 1 - PVSC	0	NSP	0	$ 28,407,840.43	$ 145,932.32
Scenario 1 - PVSC	0	NSP	2020	$ 1,649,582.38	
Scenario 1 - PVSC	0	NSP	2021	$ 1,683,009.37	
Scenario 1 - PVSC	0	NSP	2022	$ 1,704,264.66	
Scenario 1 - PVSC	0	NSP	2023	$ 1,712,737.36	
Scenario 1 - PVSC	0	NSP	2024	$ 1,760,051.67	
Scenario 1 - PVSC	0	NSP	2025	$ 1,814,392.04	
Scenario 1 - PVSC	0	NSP	2026	$ 1,800,209.97	
Scenario 1 - PVSC	0	NSP	2027	$ 1,911,860.66	
Scenario 1 - PVSC	0	NSP	2028	$ 1,929,705.81	
Scenario 1 - PVSC	0	NSP	2029	$ 1,953,234.62	
Scenario 1 - PVSC	0	NSP	2030	$ 2,034,950.12	$ 7,830.58
Scenario 1 - PVSC	0	NSP	2031	$ 2,065,810.81	$ 7,987.19
Scenario 1 - PVSC	0	NSP	2032	$ 2,157,371.78	$ 8,146.93
Scenario 1 - PVSC	0	NSP	2033	$ 2,351,758.54	$ 16,619.74
Scenario 1 - PVSC	0	NSP	2034	$ 2,441,738.21	$ 25,428.21
Scenario 1 - PVSC	0	NSP	2035	$ 2,438,894.48	$ 30,234.81
Scenario 1 - PVSC	0	NSP	2036	$ 2,560,597.50	$ 30,839.51
Scenario 1 - PVSC	0	NSP	2037	$ 2,655,190.16	$ 31,456.30
Scenario 1 - PVSC	0	NSP	2038	$ 2,803,587.59	$ 36,646.54
Scenario 1 - PVSC	0	NSP	2039	$ 2,893,829.99	$ 37,379.48
Scenario 1 - PVSC	0	NSP	2040	$ 3,060,101.93	$ 38,127.07
Scenario 1 - PVSC	0	NSP	2041	$ 3,228,972.79	$ 38,889.60

Scenario	RunID	Company	Year	Operating Cost	Carrying Costs
Scenario 1 - PVSC	0	NSP	2042	$ 3,388,535.42	$ 39,667.40
Scenario 1 - PVSC	0	NSP	2043	$ 3,521,296.07	$ 40,460.74
Scenario 1 - PVSC	0	NSP	2044	$ 3,607,707.27	$ 41,269.96
Scenario 1 - PVSC	0	NSP	2045	$ 3,837,475.99	$ 42,095.36
Scenario 1 - DW	0	NSP	0	$ 28,355,093.14	$ 176,129.97
Scenario 1 - DW	0	NSP	2023	$ 1,712,901.17	
Scenario 1 - DW	0	NSP	2024	$ 1,757,969.14	
Scenario 1 - DW	0	NSP	2025	$ 1,803,960.20	
Scenario 1 - DW	0	NSP	2026	$ 1,789,399.58	
Scenario 1 - DW	0	NSP	2027	$ 1,903,987.31	
Scenario 1 - DW	0	NSP	2028	$ 1,918,827.09	
Scenario 1 - DW	0	NSP	2029	$ 1,940,596.79	
Scenario 1 - DW	0	NSP	2030	$ 2,020,549.26	$ 7,830.58
Scenario 1 - DW	0	NSP	2031	$ 2,068,037.04	$ 7,987.19
Scenario 1 - DW	0	NSP	2032	$ 2,159,729.31	$ 8,146.93
Scenario 1 - DW	0	NSP	2033	$ 2,366,022.65	$ 16,619.74
Scenario 1 - DW	0	NSP	2034	$ 2,441,740.23	$ 25,428.21
Scenario 1 - DW	0	NSP	2035	$ 2,419,320.36	$ 30,234.81
Scenario 1 - DW	0	NSP	2036	$ 2,536,347.99	$ 30,839.51
Scenario 1 - DW	0	NSP	2037	$ 2,608,045.15	$ 31,456.30
Scenario 1 - DW	0	NSP	2038	$ 2,752,372.94	$ 36,646.54
Scenario 1 - DW	0	NSP	2039	$ 2,860,974.55	$ 37,379.48
Scenario 1 - DW	0	NSP	2040	$ 3,008,517.76	$ 38,127.07
Scenario 1 - DW	0	NSP	2041	$ 3,175,156.52	$ 38,889.60
Scenario 1 - DW	0	NSP	2042	$ 3,337,335.72	$ 39,667.40
Scenario 1 - DW	0	NSP	2043	$ 3,438,829.93	$ 40,460.74
Scenario 1 - DW	0	NSP	2044	$ 3,547,709.40	$ 41,269.96
Scenario 1 - DW	0	NSP	2045	$ 3,760,268.10	$ 42,095.36
Scenario 1 - PVSC - DW	0	NSP	0	$ 28,736,140.19	$ 145,932.32
Scenario 1 - PVSC - DW	0	NSP	2020	$ 1,750,233.25	
Scenario 1 - PVSC - DW	0	NSP	2021	$ 1,789,360.91	
Scenario 1 - PVSC - DW	0	NSP	2022	$ 1,814,321.99	
Scenario 1 - PVSC - DW	0	NSP	2023	$ 1,712,735.49	
Scenario 1 - PVSC - DW	0	NSP	2024	$ 1,760,051.76	
Scenario 1 - PVSC - DW	0	NSP	2025	$ 1,814,393.32	
Scenario 1 - PVSC - DW	0	NSP	2026	$ 1,800,223.36	
Scenario 1 - PVSC - DW	0	NSP	2027	$ 1,911,874.27	
Scenario 1 - PVSC - DW	0	NSP	2028	$ 1,929,700.69	
Scenario 1 - PVSC - DW	0	NSP	2029	$ 1,953,249.02	
Scenario 1 - PVSC - DW	0	NSP	2030	$ 2,034,956.41	$ 7,830.58
Scenario 1 - PVSC - DW	0	NSP	2031	$ 2,084,793.07	$ 7,987.19
Scenario 1 - PVSC - DW	0	NSP	2032	$ 2,176,589.55	$ 8,146.93
Scenario 1 - PVSC - DW	0	NSP	2033	$ 2,381,498.53	$ 16,619.74
Scenario 1 - PVSC - DW	0	NSP	2034	$ 2,460,663.74	$ 25,428.21
Scenario 1 - PVSC - DW	0	NSP	2035	$ 2,449,359.28	$ 30,234.81
Scenario 1 - PVSC - DW	0	NSP	2036	$ 2,570,735.98	$ 30,839.51
Scenario 1 - PVSC - DW	0	NSP	2037	$ 2,647,442.58	$ 31,456.30

Scenario	RunID	Company	Year	Operating Cost	Carrying Costs
Scenario 1 - PVSC - DW	0	NSP	2038	$ 2,791,717.75	$ 36,646.54
Scenario 1 - PVSC - DW	0	NSP	2039	$ 2,898,718.49	$ 37,379.48
Scenario 1 - PVSC - DW	0	NSP	2040	$ 3,052,354.38	$ 38,127.07
Scenario 1 - PVSC - DW	0	NSP	2041	$ 3,216,547.15	$ 38,889.60
Scenario 1 - PVSC - DW	0	NSP	2042	$ 3,386,541.97	$ 39,667.40
Scenario 1 - PVSC - DW	0	NSP	2043	$ 3,493,047.23	$ 40,460.74
Scenario 1 - PVSC - DW	0	NSP	2044	$ 3,605,858.59	$ 41,269.96
Scenario 1 - PVSC - DW	0	NSP	2045	$ 3,823,387.72	$ 42,095.36

Database	Scenario	Date Run	Runtime
ENCompass_NSP	Scenario 1	5/26/2020 8:55 AM	200.93
DW_Scenario_1_Base_PVSC	Scenario 1 - DW	11/18/2020 1:52 PM	265.43

Docket No. E002/RP- 19-368

Attachment 8

EnCompass Results

Scenario	Expansion Plan Runs (2023-2045)	MIP Stop Basis	Value
Scenario 1	Base	40	$ 28,499,086
Scenario 1 - DW	Base- DW	40	$ 28,531,223
	Delta		$ 32,137
	%Change		0.11%
Scenario 1 - D	Scenario 1 - D	50	$ 29,043,890
Scenario 1 - D - DW	Scenario 1 - D - DW	50	$ 29,071,416
	Delta		$ 27,526
	% Change		0.09%
Scenario 1 - E	Scenario 1 - E	50	$ 31,526,085
Scenario 1 - E - DW	Scenario 1 - E - DW	50	$ 31,519,627
	Delta		$ (6,458)
	%Change		-0.02%
Scenario 1 - ND Plan	Scenario 1 - ND Plan	40	$ 27,293,509
Scenario 1 - ND Plan - DW	Scenario 1 - ND Plan - DW	40	$ 27,286,240
	Delta		$ (7,269)
	% Change		-0.03%
Scenario 1 - P	Scenario 1 - P	50	$ 27,070,678
Scenario 1 - P - DW	Scenario 1 - P - DW	50	$ 27,006,497
	Delta		$ (64,181)
	%Change		-0.24%
Scenario 1 - Q	Scenario 1 - Q	50	$ 27,400,666
Scenario 1 - Q - DW	Scenario 1 - Q - DW	50	$ 27,528,015
	Delta		$ 127,350
	% Change		0.46%
Scenario 1 - S	Scenario 1 - S	50	$ 29,991,506
Scenario 1 - S - DW	Scenario 1 - S - DW	50	$ 29,872,062
	Delta		$ (119,445)
	%Change		-0.40%
Scenario 1 - U	Scenario 1 - U	50	$ 28,342,146
Scenario 1 - U - DW	Scenario 1 - U - DW	50	$ 28,346,085
	Delta		$ 3,939
	% Change		0.01%
Scenario 1 - V	Scenario 1 - V	50	$ 29,092,822
Scenario 1 - V - DW	Scenario 1 - V - DW	50	$ 29,000,801
	Delta		$ (92,021)
	%Change		-0.32%
Scenario 1 - 50 Pct ELCC	Scenario 1 - 50 Pct ELCC	40	$ 27,572,164
Scenario 1 - 50 Pct ELCC - DW	Scenario 1 - 50 Pct ELCC - DW	40	$ 27,605,013
	Delta		$ 32,849
	% Change		0.12%

Scenario	PVSC Production Cost Runs (2020-'45)	MIP Stop Basis	Value
Scenario 1 - PVSC	Scenario 1 - PVSC	20	$ 28,553,773
Scenario 1 - PVSC - DW	Scenario 1 - PVSC - DW	20	$ 28,882,073
	Delta		$ (328,300)
	%Change		1.15%
Scenario 1 - B	Scenario 1 - B	20	$ 28,476,611
Scenario 1 - B - DW	Scenario 1 - B - DW	20	$ 28,795,172
	Delta		$ (318,561)
	% Change		1.12%
Scenario 1 - C	Scenario 1 - C	20	$ 28,655,931
Scenario 1 - C - DW	Scenario 1 - C - DW	20	$ 28,995,040
	Delta		$ (339,109)
	%Change		1.18%
Scenario 1 - D - PVSC	Scenario 1 - D - PVSC	40	$ 29,417,127
Scenario 1 - D - PVSC - DW	Scenario 1 - D - PVSC - DW	40	$ 30,166,920
	Delta		$ (749,793)
	% Change		2.55%
Scenario 1 - E - PVSC	Scenario 1 - E - PVSC	20	$ 31,102,329
Scenario 1 - E - PVSC - DW	Scenario 1 - E - PVSC - DW	20	$ 31,393,248
	Delta		$ (290,920)
	%Change		0.94%
Scenario 1 - F	Scenario 1 - F	20	$ 27,093,825
Scenario 1 - F - DW	Scenario 1 - F - DW	20	$ 27,437,078
	Delta		$ (343,253)
	% Change		1.27%
Scenario 1 - G	Scenario 1 - G	20	$ 30,682,252
Scenario 1 - G - DW	Scenario 1 - G - DW	20	$ 31,012,695
	Delta		$ (330,444)
	%Change		1.08%
Scenario 1 - I	Scenario 1 - I	20	$ 27,849,836
Scenario 1 - I - DW	Scenario 1 - I - DW	20	$ 28,150,706
	Delta		$ (300,871)
	% Change		1.08%
Scenario 1 - J	Scenario 1 - J	20	$ 28,025,883
Scenario 1 - J - DW	Scenario 1 - J - DW	20	$ 28,333,377
	Delta		$ (307,494)
	%Change		1.10%
Scenario 1 - K	Scenario 1 - K	20	$ 28,310,639
Scenario 1 - K - DW	Scenario 1 - K - DW	20	$ 28,629,058
	Delta		$ (318,418)
	% Change		1.12%
Scenario 1 - L	Scenario 1 - L	20	$ 27,849,836
Scenario 1 - L - DW	Scenario 1 - L - DW	20	$ 28,150,706
	Delta		$ (300,871)
	%Change		1.08%

Scenario	PVSC Production Cost Runs (2020-'45)	MIP Stop	Value
Scenario 1 - M	Scenario 1 - M	20	$ 27,849,836
Scenario 1 - M - DW	Scenario 1 - M - DW	20	$ 28,150,706
	Delta		$ (300,871)
	% Change		1.08%
Scenario 1 - P - PVSC	Scenario 1 - P - PVSC	20	$ 28,561,094
Scenario 1 - P - PVSC - DW	Scenario 1 - P - PVSC - DW	20	$ 29,419,075
	Delta		$ (857,982)
	%Change		3.00%
Scenario 1 - Q - PVSC	Scenario 1 - Q - PVSC	20	$ 30,391,176
Scenario 1 - Q - PVSC - DW	Scenario 1 - Q - PVSC - DW	20	$ 30,862,797
	Delta		$ (471,621)
	% Change		1.55%
Scenario 1 - S - PVSC	Scenario 1 - S - PVSC	20	$ 31,620,868
Scenario 1 - S - PVSC - DW	Scenario 1 - S - PVSC - DW	20	$ 31,919,078
	Delta		$ (298,211)
	%Change		0.94%
Scenario 1 - U - PVSC	Scenario 1 - U - PVSC	20	$ 28,443,260
Scenario 1 - U - PVSC - DW	Scenario 1 - U - PVSC - DW	20	$ 28,743,156
	Delta		$ (299,896)
	% Change		1.05%
Scenario 1 - V - PVSC	Scenario 1 - V - PVSC	20	$ 29,920,432
Scenario 1 - V - PVSC - DW	Scenario 1 - V - PVSC - DW	20	$ 30,052,715
	Delta		$ (132,283)
	%Change		0.44%
Scenario 1 - 50 Pct ELCC - PVSC	Scenario 1 - 50 Pct ELCC - PVSC	20	$ 27,932,806
Scenario 1 - 50 Pct ELCC - PVSC - DW	Scenario 1 - 50 Pct ELCC - PVSC - DW	20	$ 28,299,171
	Delta		$ (366,366)
	% Change		1.31%

Scenario	PVRR Production Cost Runs	MIP Stop Basis	Value
Scenario 1 - A	Scenario 1 - A	20	$ 28,133,214
Scenario 1 - A - DW	Scenario 1 - A - DW	20	$ 28,405,263
	Delta		$ (272,049)
	%Change		0.97%
Scenario 1 - 50 Pct ELCC - A	Scenario 1 - 50 Pct ELCC - A	20	$ 27,343,962
Scenario 1 - 50 Pct ELCC - A - DW	Scenario 1 - 50 Pct ELCC - A - DW	20	$ 27,695,694
	Delta		$ (351,732)
	% Change		1.29%
Scenario 1 - ND Plan - PC	Scenario 1 - ND Plan - PC	20	$ 27,403,526
Scenario 1 - ND Plan - PC - DW	Scenario 1 - ND Plan - PC - DW	20	$ 27,678,514
	Delta		$ (274,988)
	%Change		1.00%

Scenario	Company	Year	Operating Cost	Carrying Costs
Scenario 1	NSP	0	$ 28,322,956.04	$ 176,129.97
Scenario 1	NSP	2023	$ 1,712,901.17	
Scenario 1	NSP	2024	$ 1,757,969.14	
Scenario 1	NSP	2025	$ 1,803,960.20	
Scenario 1	NSP	2026	$ 1,789,399.58	
Scenario 1	NSP	2027	$ 1,903,987.31	
Scenario 1	NSP	2028	$ 1,918,827.09	
Scenario 1	NSP	2029	$ 1,940,596.79	
Scenario 1	NSP	2030	$ 2,020,549.26	$ 7,830.58
Scenario 1	NSP	2031	$ 2,048,275.59	$ 7,987.19
Scenario 1	NSP	2032	$ 2,140,473.81	$ 8,146.93
Scenario 1	NSP	2033	$ 2,336,825.09	$ 16,619.74
Scenario 1	NSP	2034	$ 2,423,933.80	$ 25,428.21
Scenario 1	NSP	2035	$ 2,408,887.39	$ 30,234.81
Scenario 1	NSP	2036	$ 2,526,788.43	$ 30,839.51
Scenario 1	NSP	2037	$ 2,619,495.39	$ 31,456.30
Scenario 1	NSP	2038	$ 2,767,197.24	$ 36,646.54
Scenario 1	NSP	2039	$ 2,850,203.26	$ 37,379.48
Scenario 1	NSP	2040	$ 3,021,029.42	$ 38,127.07
Scenario 1	NSP	2041	$ 3,187,895.06	$ 38,889.60
Scenario 1	NSP	2042	$ 3,340,083.17	$ 39,667.40
Scenario 1	NSP	2043	$ 3,471,307.46	$ 40,460.74
Scenario 1	NSP	2044	$ 3,549,735.16	$ 41,269.96
Scenario 1	NSP	2045	$ 3,776,186.05	$ 42,095.36
Scenario 1 - PVSC	NSP	0	$ 28,407,840.43	$ 145,932.32
Scenario 1 - PVSC	NSP	2020	$ 1,649,582.38	
Scenario 1 - PVSC	NSP	2021	$ 1,683,009.37	
Scenario 1 - PVSC	NSP	2022	$ 1,704,264.66	
Scenario 1 - PVSC	NSP	2023	$ 1,712,737.36	
Scenario 1 - PVSC	NSP	2024	$ 1,760,051.67	
Scenario 1 - PVSC	NSP	2025	$ 1,814,392.04	
Scenario 1 - PVSC	NSP	2026	$ 1,800,209.97	
Scenario 1 - PVSC	NSP	2027	$ 1,911,860.66	
Scenario 1 - PVSC	NSP	2028	$ 1,929,705.81	
Scenario 1 - PVSC	NSP	2029	$ 1,953,234.62	
Scenario 1 - PVSC	NSP	2030	$ 2,034,950.12	$ 7,830.58
Scenario 1 - PVSC	NSP	2031	$ 2,065,810.81	$ 7,987.19
Scenario 1 - PVSC	NSP	2032	$ 2,157,371.78	$ 8,146.93
Scenario 1 - PVSC	NSP	2033	$ 2,351,758.54	$ 16,619.74
Scenario 1 - PVSC	NSP	2034	$ 2,441,738.21	$ 25,428.21
Scenario 1 - PVSC	NSP	2035	$ 2,438,894.48	$ 30,234.81
Scenario 1 - PVSC	NSP	2036	$ 2,560,597.50	$ 30,839.51
Scenario 1 - PVSC	NSP	2037	$ 2,655,190.16	$ 31,456.30
Scenario 1 - PVSC	NSP	2038	$ 2,803,587.59	$ 36,646.54
Scenario 1 - PVSC	NSP	2039	$ 2,893,829.99	$ 37,379.48
Scenario 1 - PVSC	NSP	2040	$ 3,060,101.93	$ 38,127.07
Scenario 1 - PVSC	NSP	2041	$ 3,228,972.79	$ 38,889.60
Scenario 1 - PVSC	NSP	2042	$ 3,388,535.42	$ 39,667.40
Scenario 1 - PVSC	NSP	2043	$ 3,521,296.07	$ 40,460.74

Scenario	Company	Year	Operating Cost	Carrying Costs
Scenario 1 - PVSC	NSP	2044	$ 3,607,707.27	$ 41,269.96
Scenario 1 - PVSC	NSP	2045	$ 3,837,475.99	$ 42,095.36
Scenario 1 - DW	NSP	0	$ 28,355,093.14	$ 176,129.97
Scenario 1 - DW	NSP	2023	$ 1,712,901.17	
Scenario 1 - DW	NSP	2024	$ 1,757,969.14	
Scenario 1 - DW	NSP	2025	$ 1,803,960.20	
Scenario 1 - DW	NSP	2026	$ 1,789,399.58	
Scenario 1 - DW	NSP	2027	$ 1,903,987.31	
Scenario 1 - DW	NSP	2028	$ 1,918,827.09	
Scenario 1 - DW	NSP	2029	$ 1,940,596.79	
Scenario 1 - DW	NSP	2030	$ 2,020,549.26	$ 7,830.58
Scenario 1 - DW	NSP	2031	$ 2,068,037.04	$ 7,987.19
Scenario 1 - DW	NSP	2032	$ 2,159,729.31	$ 8,146.93
Scenario 1 - DW	NSP	2033	$ 2,366,022.65	$ 16,619.74
Scenario 1 - DW	NSP	2034	$ 2,441,740.23	$ 25,428.21
Scenario 1 - DW	NSP	2035	$ 2,419,320.36	$ 30,234.81
Scenario 1 - DW	NSP	2036	$ 2,536,347.99	$ 30,839.51
Scenario 1 - DW	NSP	2037	$ 2,608,045.15	$ 31,456.30
Scenario 1 - DW	NSP	2038	$ 2,752,372.94	$ 36,646.54
Scenario 1 - DW	NSP	2039	$ 2,860,974.55	$ 37,379.48
Scenario 1 - DW	NSP	2040	$ 3,008,517.76	$ 38,127.07
Scenario 1 - DW	NSP	2041	$ 3,175,156.52	$ 38,889.60
Scenario 1 - DW	NSP	2042	$ 3,337,335.72	$ 39,667.40
Scenario 1 - DW	NSP	2043	$ 3,438,829.93	$ 40,460.74
Scenario 1 - DW	NSP	2044	$ 3,547,709.40	$ 41,269.96
Scenario 1 - DW	NSP	2045	$ 3,760,268.10	$ 42,095.36
Scenario 1 - PVSC - DW	NSP	0	$ 28,736,140.19	$ 145,932.32
Scenario 1 - PVSC - DW	NSP	2020	$ 1,750,233.25	
Scenario 1 - PVSC - DW	NSP	2021	$ 1,789,360.91	
Scenario 1 - PVSC - DW	NSP	2022	$ 1,814,321.99	
Scenario 1 - PVSC - DW	NSP	2023	$ 1,712,735.49	
Scenario 1 - PVSC - DW	NSP	2024	$ 1,760,051.76	
Scenario 1 - PVSC - DW	NSP	2025	$ 1,814,393.32	
Scenario 1 - PVSC - DW	NSP	2026	$ 1,800,223.36	
Scenario 1 - PVSC - DW	NSP	2027	$ 1,911,874.27	
Scenario 1 - PVSC - DW	NSP	2028	$ 1,929,700.69	
Scenario 1 - PVSC - DW	NSP	2029	$ 1,953,249.02	
Scenario 1 - PVSC - DW	NSP	2030	$ 2,034,956.41	$ 7,830.58
Scenario 1 - PVSC - DW	NSP	2031	$ 2,084,793.07	$ 7,987.19
Scenario 1 - PVSC - DW	NSP	2032	$ 2,176,589.55	$ 8,146.93
Scenario 1 - PVSC - DW	NSP	2033	$ 2,381,498.53	$ 16,619.74
Scenario 1 - PVSC - DW	NSP	2034	$ 2,460,663.74	$ 25,428.21
Scenario 1 - PVSC - DW	NSP	2035	$ 2,449,359.28	$ 30,234.81
Scenario 1 - PVSC - DW	NSP	2036	$ 2,570,735.98	$ 30,839.51
Scenario 1 - PVSC - DW	NSP	2037	$ 2,647,442.58	$ 31,456.30
Scenario 1 - PVSC - DW	NSP	2038	$ 2,791,717.75	$ 36,646.54
Scenario 1 - PVSC - DW	NSP	2039	$ 2,898,718.49	$ 37,379.48
Scenario 1 - PVSC - DW	NSP	2040	$ 3,052,354.38	$ 38,127.07
Scenario 1 - PVSC - DW	NSP	2041	$ 3,216,547.15	$ 38,889.60

Scenario	Company	Year	Operating Cost	Carrying Costs
Scenario 1 - PVSC - DW	NSP	2042	$ 3,386,541.97	$ 39,667.40
Scenario 1 - PVSC - DW	NSP	2043	$ 3,493,047.23	$ 40,460.74
Scenario 1 - PVSC - DW	NSP	2044	$ 3,605,858.59	$ 41,269.96
Scenario 1 - PVSC - DW	NSP	2045	$ 3,823,387.72	$ 42,095.36

Scenario	RunID	PlanID	PV Cost ($000)
Scenario 1	0	1	12784358.4
Scenario 1 - DW	0	1	12776957.95

Database	Scenario	Date Run	Runtime
ENCompass_NSP	Scenario 1	5/26/2020 8:55 AM	200.93
DW_Scenario_1_Sensitivities	Scenario 1 - DW	11/18/2020 1:52 PM	265.43

Docket No. E002/RP- 19-368

Attachment 9

EnCompass Work Plan

Note: Matrix provided to Department by Xcel via email

Department Matched

Department to Match in Reply Comments

Description	Parent Run	Child Runs	Base	Base - PVSC	A-PVRR	B-Low Gas/Coal/ Markets	C-High Gas/ Coal/Markets	D-Low Load (High DER)	D - PVSC	E-High Load (Electrification)	E - PVSC
REFERENCE	**Scenario 1**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY KING	**Scenario 2**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY SH3	**Scenario 3**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY COAL	**Scenario 4**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY MONTI	**Scenario 5**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY PI	**Scenario 6**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY All NUCLEAR	**Scenario 7**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY BASELOAD	**Scenario 8**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY COAL; EXTEND MONTI	**Scenario 9**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice
	Scenario 9	Wind Available 2023 @ $500/kW	Optimize	RePrice	RePrice						
	Scenario 9	Solar @ 50% ELCC Throughout	Optimize	RePrice	RePrice						
	Scenario 9	Unconstrained Sales/Purchase Volume	Optimize	RePrice	RePrice						
	Scenario 9	Sherco CC Alternatives - 7HA01 1x1	Optimize	RePrice	RePrice						
	Scenario 9	Sherco CC Alternatives - 7HA02 1x1	Optimize	RePrice	RePrice						
	Scenario 9	Sherco CC Alternatives - 7HA02 2x1	Optimize	RePrice	RePrice						
	Scenario 9	Sherco CC Alternatives - No CC	Optimize	RePrice	RePrice						
	Scenario 9	Solar + Storage: "swap" 1st solar addition	Optimize	RePrice	RePrice						
	Scenario 9	Solar + Storage: "optimize" 1st solar addition	Optimize								
	Scenario 9	Wind + Storage: "swap" 1st wind addition	Optimize	RePrice	RePrice						
	Scenario 9	Wind + Storage: "optimize" 1st wind addition	Optimize								
	Scenario 9	DSM/DR - Add DR Bundle 2	Optimize	RePrice	RePrice						
	Scenario 9	DSM/DR - Add EE Bundle 3	Optimize	RePrice	RePrice						
EARLY KING; EXTEND MONTI	**Scenario 10**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY COAL; EXTEND PI	**Scenario 11**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY COAL; EXTEND All NUCLEA	**Scenario 12**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice
EXTEND MONTI	**Scenario 13**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice
EXTEND PI	**Scenario 14**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice
EXTEND All NUCLEAR	**Scenario 15**		Optimize	RePrice	RePrice	RePrice	RePrice	Optimize	RePrice	Optimize	RePrice

Note: Matrix provided to Department by Xcel via email

Department Matched

Department to Match in Reply Comments

Description	Parent Run	Child Runs	F-Low Resource Cost	G-High Resource Cost	I-Low Externality	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs
REFERENCE	**Scenario 1**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice
EARLY KING	**Scenario 2**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice
EARLY SH3	**Scenario 3**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice
EARLY COAL	**Scenario 4**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice
EARLY MONTI	**Scenario 5**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice
EARLY PI	**Scenario 6**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice
EARLY All NUCLEAR	**Scenario 7**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice
EARLY BASELOAD	**Scenario 8**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice
EARLY COAL; EXTEND MONTI	**Scenario 9**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice
	Scenario 9	Wind Available 2023 @ $500/kW							
	Scenario 9	Solar @ 50% ELCC Throughout							
	Scenario 9	Unconstrained Sales/Purchase Volume							
	Scenario 9	Sherco CC Alternatives - 7HA01 1x1			RePrice	RePrice	RePrice	RePrice	RePrice
	Scenario 9	Sherco CC Alternatives - 7HA02 1x1			RePrice	RePrice	RePrice	RePrice	RePrice
	Scenario 9	Sherco CC Alternatives - 7HA02 2x1			RePrice	RePrice	RePrice	RePrice	RePrice
	Scenario 9	Sherco CC Alternatives - No CC			RePrice	RePrice	RePrice	RePrice	RePrice
	Scenario 9	Solar + Storage: "swap" 1st solar addition			RePrice	RePrice	RePrice	RePrice	RePrice
	Scenario 9	Solar + Storage: "optimize" 1st solar addition							
	Scenario 9	Wind + Storage: "swap" 1st wind addition			RePrice	RePrice	RePrice	RePrice	RePrice
	Scenario 9	Wind + Storage: "optimize" 1st wind addition							
	Scenario 9	DSM/DR - Add DR Bundle 2			RePrice	RePrice	RePrice	RePrice	RePrice
	Scenario 9	DSM/DR - Add EE Bundle 3			RePrice	RePrice	RePrice	RePrice	RePrice
EARLY KING; EXTEND MONTI	**Scenario 10**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice
EARLY COAL; EXTEND PI	**Scenario 11**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice
EARLY COAL; EXTEND All NUCLE	**Scenario 12**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice
EXTEND MONTI	**Scenario 13**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice
EXTEND PI	**Scenario 14**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice
EXTEND All NUCLEAR	**Scenario 15**		RePrice	RePrice	RePrice	RePrice	RePrice	RePrice	RePrice

Note: Matrix provided to Department by Xcel via email

Department Matched (green)

Department to Match in Reply Comments (yellow)

								TBD	TBD		
Description	**Parent Run**	**Child Runs**	**N-Markets Off**	**P - Combo "DBF"**	**P - PVSC**	**Q - Combo "ECF"**	**Q - PVSC**	**R - Reshape Market to Net Load**	**R - PVSC**	**S - No Carbon Adder for Sales**	**S - PVSC**
REFERENCE	**Scenario 1**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY KING	**Scenario 2**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY SH3	**Scenario 3**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY COAL	**Scenario 4**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY MONTI	**Scenario 5**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY PI	**Scenario 6**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY All NUCLEAR	**Scenario 7**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY BASELOAD	**Scenario 8**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY COAL; EXTEND MONTI	**Scenario 9**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
	Scenario 9	Wind Available 2023 @ $500/kW						-			
	Scenario 9	Solar @ 50% ELCC Throughout						-			
	Scenario 9	Unconstrained Sales/Purchase Volume						-			
	Scenario 9	Sherco CC Alternatives - 7HA01 1x1	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
	Scenario 9	Sherco CC Alternatives - 7HA02 1x1	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
	Scenario 9	Sherco CC Alternatives - 7HA02 2x1	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
	Scenario 9	Sherco CC Alternatives - No CC	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
	Scenario 9	Solar + Storage: "swap" 1st solar addition						-			
	Scenario 9	Solar + Storage: "optimize" 1st solar addition						-			
	Scenario 9	Wind + Storage: "swap" 1st wind addition						-			
	Scenario 9	Wind + Storage: "optimize" 1st wind addition						-			
	Scenario 9	DSM/DR - Add DR Bundle 2						-			
	Scenario 9	DSM/DR - Add EE Bundle 3									
EARLY KING; EXTEND MONTI	**Scenario 10**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY COAL; EXTEND PI	**Scenario 11**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY COAL; EXTEND All NUCLEA	**Scenario 12**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EXTEND MONTI	**Scenario 13**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EXTEND PI	**Scenario 14**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EXTEND All NUCLEAR	**Scenario 15**		RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice

Note: Matrix provided to Department by Xcel via email

Department Matched

Department to Match in Reply Comments

Description	Parent Run	Child Runs	TBD T - Hourly Carbon, Net Load Shape	TBD T - PVSC	U - Hourly Carbon, Retail Load Shape	U - PVSC	V - Optimize with Externality in model	V - PVSC
REFERENCE	**Scenario 1**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY KING	**Scenario 2**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY SH3	**Scenario 3**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY COAL	**Scenario 4**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY MONTI	**Scenario 5**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY PI	**Scenario 6**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY All NUCLEAR	**Scenario 7**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY BASELOAD	**Scenario 8**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY COAL; EXTEND MONTI	**Scenario 9**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
	Scenario 9	Wind Available 2023 @ $500/kW	-					
	Scenario 9	Solar @ 50% ELCC Throughout	-					
	Scenario 9	Unconstrained Sales/Purchase Volume	-					
	Scenario 9	Sherco CC Alternatives - 7HA01 1x1	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
	Scenario 9	Sherco CC Alternatives - 7HA02 1x1	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
	Scenario 9	Sherco CC Alternatives - 7HA02 2x1	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
	Scenario 9	Sherco CC Alternatives - No CC	Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
	Scenario 9	Solar + Storage: "swap" 1st solar addition	-					
	Scenario 9	Solar + Storage: "optimize" 1st solar addition	-					
	Scenario 9	Wind + Storage: "swap" 1st wind addition	-					
	Scenario 9	Wind + Storage: "optimize" 1st wind addition	-					
	Scenario 9	DSM/DR - Add DR Bundle 2	-					
	Scenario 9	DSM/DR - Add EE Bundle 3						
EARLY KING; EXTEND MONTI	**Scenario 10**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY COAL; EXTEND PI	**Scenario 11**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EARLY COAL; EXTEND All NUCLE/	**Scenario 12**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EXTEND MONTI	**Scenario 13**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EXTEND PI	**Scenario 14**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice
EXTEND All NUCLEAR	**Scenario 15**		Optimize	RePrice	Optimize	RePrice	Optimize	RePrice

Docket No. E002/RP- 19-368

Attachment 10

EnCompass Expansion Plan

Scenario:	Dept New Base Scenario 1	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
	Sherburne County CC	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
	CT H Generic	-	-	-	-	-	-	-	-	-	-	-	1	-	-	1	1	-	-	1	-	-	-	-	-	-	-	4
	DR_CP_1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
	DR_INT_1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
	DR_SS_1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
	EE_1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
	EE_2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
	B23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B32	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B37	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B45	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S32	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	3
	S33	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	3
	S34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	2
	S35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	2
	S36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S37	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	S41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Scenario: Dept New Base Scenario 1	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
S42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
S43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
S44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
S45	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W32	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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W38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
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W40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
W45	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
COAL_LBC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	1	-	-	-	-	-	-	-	2
NUKE_LBC	-	-	-	-	-	-	-	-	-	-	1	-	-	1	1	-	-	-	-	-	-	-	-	-	-	-	3

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
DW Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	1	-	-	-	-	-	-	-	2
SR Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	2
Difference																											-
DW Solar	-	-	-	-	-	-	-	-	-	-	-	-	3	3	2	2	-	-	-	-	-	-	-	-	-	-	10
SR Solar	-	-	-	-	-	-	-	-	-	-	-	2	2	2	3	5	-	-	-	-	-	-	-	-	-	-	14
Difference																											-
DW Other	5	-	-	-	-	-	-	-	-	-	1	-	-	1	1	1	-	-	1	-	-	-	-	-	-	-	10
SR Other	3	-	-	-	-	-	-	-	-	-	1	-	-	1	1	1	-	-	1	-	-	-	-	-	-	-	8
Difference																											-
DW CC	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
SR CC	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
Difference																											-
DW CT	-	-	-	-	-	-	-	-	-	-	-	1	-	-	1	1	-	-	1	-	-	-	-	-	-	-	4
SR CT	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	1	-	-	-	-	-	-	-	2
Difference																											-

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Comments

Docket No. E002/RP-19-368

Dated this 11th day of February 2021

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Gary	Ambach	Gambach@slipstreaminc.org	Slipstream, Inc.	8973 SW Village Loop Chanhassen, MN 55317	Electronic Service	No	OFF_SL_19-368_19-368_Official
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_19-368_19-368_Official
Susan	Arntz	sarntz@mankatomn.gov	City Of Mankato	P.O. Box 3368 Mankato, MN 560023368	Electronic Service	No	OFF_SL_19-368_19-368_Official
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-368_19-368_Official
Jessica L	Bayles	Jessica.Bayles@stoel.com	Stoel Rives LLP	1150 18th St NW Ste 325 Washington, DC 20036	Electronic Service	No	OFF_SL_19-368_19-368_Official
David	Bender	dbender@earthjustice.org	Earthjustice	1001 G Street NW Suite 1000 Washington, District of Columbia 20001	Electronic Service	No	OFF_SL_19-368_19-368_Official
Tracy	Bertram	tbertram@ci.becker.mn.us		12060 Sherburne Ave Becker City Hall Becker, MN 55308-4694	Electronic Service	No	OFF_SL_19-368_19-368_Official
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
Jessica	Beyer	jbeyer@greatermankato.com	Greater Mankato Growth	1961 Premier Dr Ste 100 Mankato, MN 56001	Electronic Service	No	OFF_SL_19-368_19-368_Official
Melissa E	Birchard	mbirchard@keyesfox.com	KEYES & FOX LLP	18 Loudon Rd PO Box 1391 Concord, NH 03302	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael J.	Bull	mbull@mncee.org	Center for Energy and Environment	212 Third Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-368_19-368_Official
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-368_19-368_Official
Thomas	Carlson	thomas.carlson@edf-re.com	EDF Renewable Energy	10 2nd St NE Ste. 400 Minneapolis, Minnesota 55413	Electronic Service	No	OFF_SL_19-368_19-368_Official
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_19-368_19-368_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-368_19-368_Official
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Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_19-368_19-368_Official
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