Xcel Energy

Life Cycle Management Study for Sherburne County (Sherco) Generating Station Units 1 and 2

Minnesota Public Utilities Commission Docket Number E002/RP-13-368

July 1, 2013

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

July 1, 2013

—Via Electronic Filing—

Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

Re: SHERBURNE COUNTY (SHERCO) GENERATING STATION UNITS 1 AND 2
LIFE CYCLE MANAGEMENT STUDY
DOCKET NO. E002/RP-13-368

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Life Cycle Management Study for the Sherburne County Generating Station Units 1 and 2 as required by paragraph 4 of the Minnesota Public Utilities Commission's November 30, 2012 ORDER in the Company's most recent Resource Plan (Docket No. E002/RP-10-825).

We have electronically filed this document with the Commission and copies have been served on the parties on the attached service lists. The study can be accessed by searching for Docket No. E002/RP-13-368 at the following website: https://www.edockets.state.mn.us/EFiling/home.jsp.

Please contact me at james.r.alders@xcelenergy.com or (612) 330-6732 if you have any questions regarding this filing.

Sincerely,

/s/

JAMES R. ALDERS
STRATEGY CONSULTANT
REGULATORY AFFAIRS

Enclosures
c: Service Lists

CERTIFICATE OF SERVICE

I, Ketti R. Lindberg, hereby certify that I have this day served copies of the foregoing document or a summary thereof on the attached list of persons.

xx by depositing a true and correct copy or summary thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota; or

xx via electronic filing

- **Docket No. E002/RP-10-825**
- **Minnesota Environmental Quality Board**
- **Stakeholders and Other Interested Parties**

(Regarding Filing in Docket No. E002/RP-13-368)

Dated this 1st day of July 2013

/s/

____
Ketti R. Lindberg

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Life Cycle Management Study for Sherburne County (Sherco) Generating Station Units 1 and 2

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Appendices

Chapter 1. Executive Summary

The Sherburne County (Sherco) generating facility in Becker, Minnesota is the Company's largest power plant in the Midwest, with its three units capable of providing a total of 2,400 MW of electricity. Units 1 and 2 have a production capability of 750 MW each for total capacity of 1,500 MW and provide approximately 20% of the electricity used by our Minnesota customers each year. As a baseload facility, Sherco is available 24 hours a day, seven days a week, giving it a critical role in meeting our customers' energy needs. Sherco's size, age, role in our generation fleet, and existing pollution control investments differentiate it from other coal-fired power plants in Minnesota that have been retired or are scheduled to be retired in the next few years.

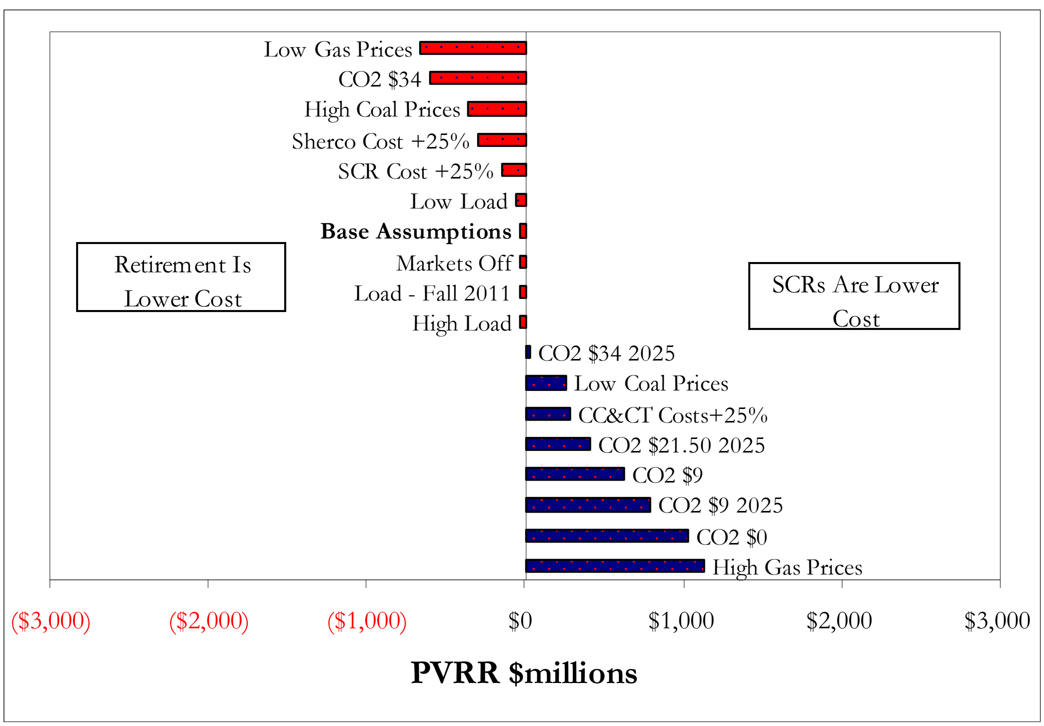
In our 2010 Resource Plan filing, the Company noted that Sherco 1 and 2 are over thirty years old and that we had begun the process of investigating how best to manage the units for the future. In its November 30, 2012 Resource Plan Order, the Commission directed the Company to prepare a study that examines the cost of continuing to operate Sherco 1 and 2 and evaluates retrofit and retirement scenarios. To ensure that the Commission has a comprehensive view of the risks and benefits of the various options for Sherco 1 and 2, the Company has completed extensive modeling, thoroughly reviewed the status of environmental regulation, and engaged stakeholders of various backgrounds and perspectives.

The Company used the Strategist resource planning model to evaluate the cost of retrofitting the units with additional pollution control equipment or retiring Sherco 1 and 2. The retrofit scenarios evaluate the installation of Selective Catalytic Reduction (SCR) pollution control equipment, while the retirement scenarios evaluate replacing Sherco 1 and 2 with new natural gas generation, renewable energy, and conservation or a combination of those options. With the assistance of consulting engineers, the Company conducted an extensive review of the capital investments and operations and maintenance expenses necessary to keep the plant running efficiently and reliably. We have carefully evaluated the costs of replacement generation, including estimating the cost of supplying natural gas to a replacement combustion turbine or combined cycle unit and upgrading or adding transmission capacity to deliver energy from new generation resources.

The scenarios were tested under a wide range of assumptions about the future to understand the sensitivity of the analysis to changes in input assumptions. These sensitivities include suggestions from our stakeholders that help further test the results. The modeling results show that when the anticipated direct costs to operate Sherco 1 and 2 (including SCRs) are compared to the alternatives, continued operation of Sherco 1 and 2 is clearly the most cost-effective option. Only a significantly lower forecast of natural gas prices or a much higher forecast of coal prices calls that conclusion into question.

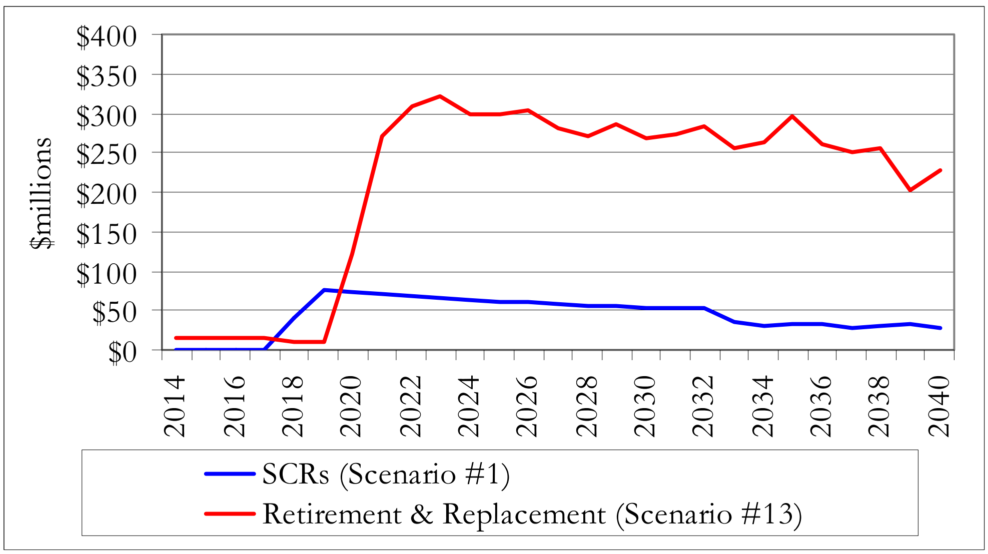
When the Commission's carbon proxy cost values are applied, however, there is very little cost difference over the long term between continued operation and some of the replacement scenarios. Thus, the timing and cost of carbon regulation is a key factor in determining the relative costs of retrofit and retirement scenarios. Figure 1.1 compares the present value of revenue requirements (PVRR) of retirement of Sherco 1 and 2 in 2019 and 2020 to the alternative of retrofitting the units with SCRs and continuing operations until 2040. As the chart shows, under the base assumptions, including a carbon dioxide (CO_2) cost of \$21.50/ton, the cost difference between installing SCRs and retiring the units is negligible. This implies that there is no significant cost advantage of either the retirement or the retrofit strategies with carbon priced at \$21.50/ton. The chart also illustrates which input assumption sensitivities favor which strategy and how much they change the PVRR results. Low gas prices, higher CO_2 prices, higher coal prices, or higher costs at Sherco favor retirement. Assumption sensitivities that favor the installation of SCRs and continued operation include higher natural gas prices, lower CO_2 costs or later implementation of CO_2 costs, low coal prices, or higher construction cost for new natural gas plants. The load sensitivities have little effect.

Figure 1.1: Summary of PVRR Results



Another method of evaluating the scenarios is to estimate the annual costs to customers. Figure 1.2 shows the projected annual costs to customers of early installation of SCRs and early retirement of Sherco 1 and 2. The chart is based on the \$0/ton CO_2 sensitivity simulations to align with current regulatory conditions and the expectation that there will not be carbon regulation in effect by 2017. The chart illustrates that installation of SCRs on both units would results in a total annual cost of almost \$75 million and the cost of retirement and replacement could exceed \$300 million.

Figure 1.2: Annual Cost Impacts of SCRs and Retirement Strategies



As previously mentioned, the cost and timing of carbon regulation is a key driver of the results. Yet it is unknown what kind of carbon policy will ultimately be adopted and how that that policy will affect existing coal-fired power plants like Sherco 1 and 2. Similarly, there is considerable uncertainty around the need to further reduce NO_X emissions. Units 1 and 2 are well-positioned to comply with current environmental regulations and do not need SCRs at this time. However, SCRs might be required if Minnesota has areas that do not meet the ozone NAAQS as it may be revised in 2014 or falls into nonattainment for particulate matter. Additionally, the Company could be required to install SCRs under the Regional Haze Rule or "reasonably attributable visibility impairment" (RAVI) visibility regulations, which is currently subject to litigation between the Environmental Protection Agency and environmental advocates. While the timing is uncertain, we anticipate that SCRs may be required late this decade or sometime the following decade.

This uncertainty is particularly relevant because it is these regulatory factors that drive when a decision on the future of Sherco 1 and 2 needs to be made and the cost-effectiveness of the various scenarios. The Company has not identified factors that suggest action should be taken immediately. As shown in the charts above, advancing installation of SCRs or beginning the process of replacing Sherco 1 and 2 will have a significant impact on customer rates. Each SCR is estimated to cost approximately $170 million in 2012 dollars. The cost to replace both Sherco units with combined cycle natural gas plants, for example, is estimated at $1.7 billion.

The Company believes the most prudent course of action at this time is to continue to operate Sherco 1 and 2 as we await greater clarity and certainty around the development of environmental regulation and the resulting timing and costs. This strategy aligns the timing of a decision on the future of Sherco 1 and 2 with the availability of more complete information. To ensure timely action when additional information becomes available, we recommend the Commission establish firm triggers for reevaluation and future decision-making. Specifically, we recommend the Commission require reanalysis when: 1) air quality regulations establish a need for SCRs, or 2) a carbon regulation framework takes shape. Should an SCR requirement emerge prior to development of carbon regulation, the Company will reevaluate the cost-effectiveness of installing SCRs and recovering the cost over a shorter period to preserve the option to retire the units earlier than 2040 in the event of eventual carbon regulation.

Chapter 2. Introduction

The Company develops integrated resource plans to identify the expected demand for electricity over a 15-year period and propose options for reliably meeting the projected need. The decisions made in resource plan proceedings directly affect what generation resources are planned and when they are constructed. The decisions also impact the amount of conservation and demand-side resources targeted in the Company's Conservation Improvement Program (CIP).

As part of the Company's 2011-2025 Integrated Resource Plan, the Company agreed to complete a Life Cycle Management Study for Sherco Units 1 and 2. The Commission's Resource Plan Order requires the Company, by July 1, 2013, to:

> …submit a Sherco Life Cycle Management Study that examines the feasibility and cost-effectiveness of continuing to operate, retrofitting, or retiring Sherburne County (Sherco) Generating Station Units 1 and 2. Procedurally, interested parties shall have the opportunity to intervene, conduct discovery, and comment.[1]

The Commission's Order also outlined minimum required study components, including:

- Specific cost estimates of controls and other required investments.
- An analysis of how a temporary or permanent outage at either Sherco 1 or 2 would affect system reliability.
- A base case that includes Commission-adopted carbon dioxide (CO_2) costs and externality values.
- A base case that accounts for all likely federal Environmental Protection Agency (EPA) regulations.
- Analysis of scenarios that include the following:
  - A range of updated externality values based on those used by Commission and federal government for regulatory impact analysis.
  - A wide range of fuel prices.
  - Least-cost scenarios to reduce greenhouse gasses relative to 2005 levels by at least 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050.
  - Least-cost plans for replacing 50 and 75 percent of the capacity of Sherco 1 and 2 through a combination of conservation and capacity powered by renewable sources of energy.

[1] Docket No. E002/RP-10-825, ORDER ESTABLISHING PROCEDURAL SCHEDULES AND FILING REQUIREMENTS (November 30, 2012).

This study addresses all components of the Commission's Order and provides additional information in response to input from interested parties that advised the Company on the study. Through the stakeholder engagement process, we aimed to:

- Develop modeling scenarios, modeling assumptions, and study contents that reflected stakeholders' interests and perspectives;
- Maintain transparency of the modeling process and proactively address stakeholder concerns and requests for information;
- Develop shared understanding of modeling results; and
- Lay the groundwork for successful continuation of stakeholder engagement following study submission.

We appreciate the thoughtful and constructive input provided by the stakeholders, and believe their involvement resulted in a comprehensive and objective study. The following organizations participated in the stakeholder process:

- Minnesota Department of Commerce, Division of Energy Resources
- Minnesota Department of Natural Resources
- Minnesota Pollution Control Agency
- North Dakota Public Service Commission (Staff)
- South Dakota Public Service Commission (Staff)
- City of Becker, Minnesota
- Liberty Paper Inc.
- Minnesota Chamber of Commerce
- Xcel Large Industrials
- Center for Energy and the Environment
- Fresh Energy
- Izaak Walton League, Midwest Office
- Minnesota Center for Environmental Advocacy
- Sierra Club

This study helps inform our next Resource Plan, which is scheduled to be filed February 1, 2014. It is in the context of the next Resource Plan, and not this study, that the size, type, and timing of future resources will be decided. In this study, we provide the information needed to evaluate the benefits and risks of the various options for Sherco 1 and 2.

Chapter 3. Background

A. NSP Generation Portfolio

The NSP Electric System serves over 1.6 million electric customers in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan. Together, NSP's generating plants have a net maximum capacity of over 8,300 MW.[2] Our generating facilities use a variety of fuel sources including coal, natural gas, nuclear fuel, water (hydro), oil, and refuse; we also have facilities that generate electricity from the wind and sun. We strive to operate our plants safely and responsibly and have a national reputation for operational excellence and environmental stewardship. Figure 3.1 shows the NSP System fuel mix as a percent of total energy generated and purchased in 2012. Figure 3.2 shows the fuel mix as a percent of 2012 accredited capacity.

Figure 3.1: NSP System Energy Mix, 2012[3]

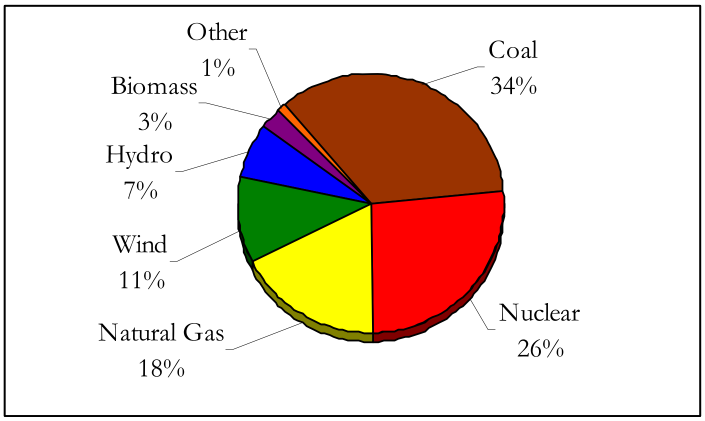
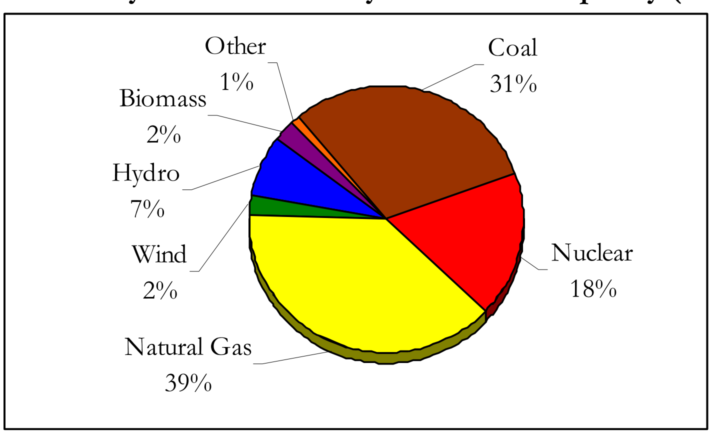


Figure 3.2: NSP System Fuel Mix by Accredited Capacity (MW), 2012[4]



[2] The Net Maximum Capacity (NMC) is defined as the unit's Gross Maximum Capacity less any capacity (MW) that is used for that unit's station service or auxiliary load.
[3] 2012 actual generation reflects unavailability of Sherco Unit 3 for all of 2012.
[4] Unforced capacity or UCAP includes an adjustment for recent forced outage factors. This figure includes capacity for Sherco 3 to be more representative of typical NSP system.

Our generation portfolio has evolved over time as a result of state and federal energy policies and regulations and Company-driven efforts to improve efficiencies and environmental performance. For example, to comply with the Minnesota Renewable Energy Standard, we have added over 1,200 MW of renewable energy to the NSP System since 2006, including wind, hydro, biomass, and solar resources. We have nearly 1,900 MW of commercial wind capacity on the NSP System through purchased power contracts and owned assets. We also have approximately 10 MW_{DC} of solar generation on our system from a combination of distributed generation sites and the 2 MW solar installation in Slayton, Minnesota. The expansion of our renewable energy portfolio helped us lower carbon emissions by 22% over the 2005 to 2012 period.

Through the Metropolitan Emissions Reduction Project (MERP), the Company made extensive voluntary efforts to reduce air emissions from three Twin Cities coal-powered generating plants, while increasing the amount of electricity they produce. MERP projects included adding state-of-the-art emissions controls to the coal-fired Allen S. King plant in Oak Park Heights, Minnesota; replacing the coal-fired High Bridge plant built in 1923 near downtown St. Paul with a natural gas-fired combined-cycle plant; and repowering the coal-fired Riverside plant running since 1911 in northeast Minneapolis with natural gas-fired combined-cycle units. As a result of these efforts, the nitrogen oxide (NO_X), sulfur dioxide (SO_2), and particulate matter (PM) emissions from those three plants were reduced by 90% or more and carbon dioxide (CO_2) emissions were reduced by 40%.[5]

We are also making significant investments in our nuclear facilities to keep them operating safely and reliably for the next 20 years. Xcel Energy owns and operates three nuclear units in Minnesota: one unit at Monticello and two units at Prairie Island in Welch. These plants have provided safe, efficient, and clean energy to our customers since the 1970s. We proposed and the Commission approved extending the life of these plants and increasing power output at our Monticello nuclear plant.

We expect our generation portfolio to continue to evolve as some of our older plants are refurbished or retired and we add new generation to the system. Based on our current Resource Planning estimates, we expect to retire the older, coal-fired units at our Black Dog generation facility (Units 3 and 4) by spring 2015 and the peaking units at Key City in Mankato and at Granite City near St. Cloud in 2018, for total retirements of approximately 370 MW of fossil-fuel fired production capacity.

[5] http://www.xcelenergy.com/About_Us/Energy_News/News_Archive/Xcel_Energy_completes_ Twin_Cities_Metro_Emissions_Reduction_Project.

The Commission's March 5, 2012 Order in Docket No. E002/RP-10-825 determined that the record demonstrates a need for an additional 150 MW by 2017, increasing up to 500 MW by 2019. The Company is engaged in a competitive resource acquisition process to meet the identified need.[6] We are also currently evaluating bids for additional wind resources to begin construction this year. The Company will pursue additional solar resources in order to comply with the solar energy standard passed by the 2013 Legislature, requiring 1.5 percent of retail sales to come from solar energy by 2020.[7]

[6] Docket No. E002/CN-12-1240.
[7] Minn. Stat. §216B.1691, subd. 2f.

Chapter 4. Sherco Units 1 and 2

The Sherco generating plant is the Company's largest plant in the Midwest, located 45 miles northwest of the Twin Cities in Becker, Minnesota. It is a three-unit, coal-fired power plant capable of providing enough power to serve more than two million typical homes. Units 1 and 2 have a production capability of 750 MW each for total capacity of 1,500 MW.[8] As a baseload facility, Sherco is available 24 hours a day, seven days a week, giving it a critical role in meeting our customers' energy needs.

Sherco 1 and 2 were built in the 1970s to meet the growing demand for electricity and to reduce the use of older, less efficient plants. The plant was constructed on a 4,500-acre site to accommodate future expansion. A third unit was built in 1983-1987, which at the time marked the largest construction project ever in the state of Minnesota. Sherco Unit 3 is co-owned by Xcel Energy (59%) and Southern Minnesota Municipal Power Agency (41%).

A. Existing and Pending Pollution Control Equipment

The development of environmental regulation coincided with the development of Sherco Units 1 and 2. These units became operational in 1976 and 1977 to meet the growing demand for electricity and to reduce the use of older, less efficient plants. Sherco 1 and 2 were specifically designed to be well-controlled units in order to minimize their impact on the environment. For example, wet scrubbers control PM and SO_2 emissions. State-of-the-art cooling water intake structures limit the impacts on aquatic organisms and closed cycle cooling limits the impacts of heated water discharge from the power plant. Land resources were protected by the design and construction of engineered ash ponds to ensure safe handling of ash generated from the units.

The environmental controls for Sherco 1 and 2 have continued to be enhanced as new technology and environmental regulations have developed. For example, new particulate emission controls were installed in the late 1990s. Wet electrostatic precipitators (WESPs) were added to the scrubbers to further remove PM, especially fine particles. To lower emissions of NO_X several projects have been completed, including:

[8] The net dependable production capacity is 681MW for Unit 1and 682 MW for Unit 2.

- Low NO_X burners (LNBs) with separated and closed coupled overfire air (OFA) on Unit 2 in 1995;
- Replacement of furnace dampers and associated controls to help optimize combustion on Unit 2 in 2006; and
- LNB with separated and closed coupled OFA on Unit 1 in 2007.

The air emissions control devices are being upgraded from the original scrubber design to incorporate new sparger tubes, which increases the SO_2 removal capacity of the systems, and new electrodes and higher frequency power supplies are being installed on the WESPs to improve PM removal. With completion of the sorbent injection system for mercury (Hg) control in 2014, Sherco Units 1 and 2 will have control devices in place for PM, SO_2 and Hg that will reduce emissions to levels consistent with Best Available Control Technology (BACT) or BACT-equivalent technology for retrofit units. Below we discuss the existing pollution control equipment by pollutant and historical and forecasted emissions performance. Table 4.1 summarizes the existing pollution control equipment and equipment currently being installed.

Table 4.1: Existing and Pending Pollution Control Equipment

Effluent	Control Equipment Description	Existing	In Progress
PM	Wet Particulate Scrubber	X	
	Wet Electrostatic Precipitator (WESP)	X	
	High Frequency Power Supplies and Upgraded Electrodes on WESP		2012-14
NO_X	Low NOx Burners	X	
	Over Fire Air	X	
	Combustion Optimization Systems	X	
SO_2	Wet Flue Gas Desulfurization (WFGD)/ Wet Particulate Scrubber	X	
	Sparger Tubes in Scrubber/WESP modules		2012-14
Hg	Activated Carbon Injection		2014
Ash	Fly Ash Disposal Ponds	X	
	Bottom Ash Disposal Ponds	X	
Water	Water Recycling	X	
	Advanced Screen Technology	X	
	Closed Cycle Cooling	X	

1. *Particulate Matter (PM)*

Sherco 1 and 2 were originally equipped with venturi scrubber modules – a type of wet scrubber – for control of particulate matter. The venturi scrubber modules have been retrofit with wet electrostatic precipitators (WESP) to increase the removal capacity of the control devices. A WESP collects negatively-charged particles on positively-charged surfaces, which are flushed with water to remove the particulates. At Sherco 1 and 2, the WESP is installed downstream of an existing wet flue gas desulfurization (WFGD) system, where the flue gas is already saturated, thus minimizing the amount of added water. The Company is currently installing new high frequency power supplies on each module to allow significantly higher electrical voltage and current to each WESP field, which results in reduced particulate emissions. In addition, an upgrade of the electrodes is being completed, which will increase the overall electrode coverage and improve performance. This work will be completed by the end of 2014.

2. *Nitrogen Oxides (NO_X)*

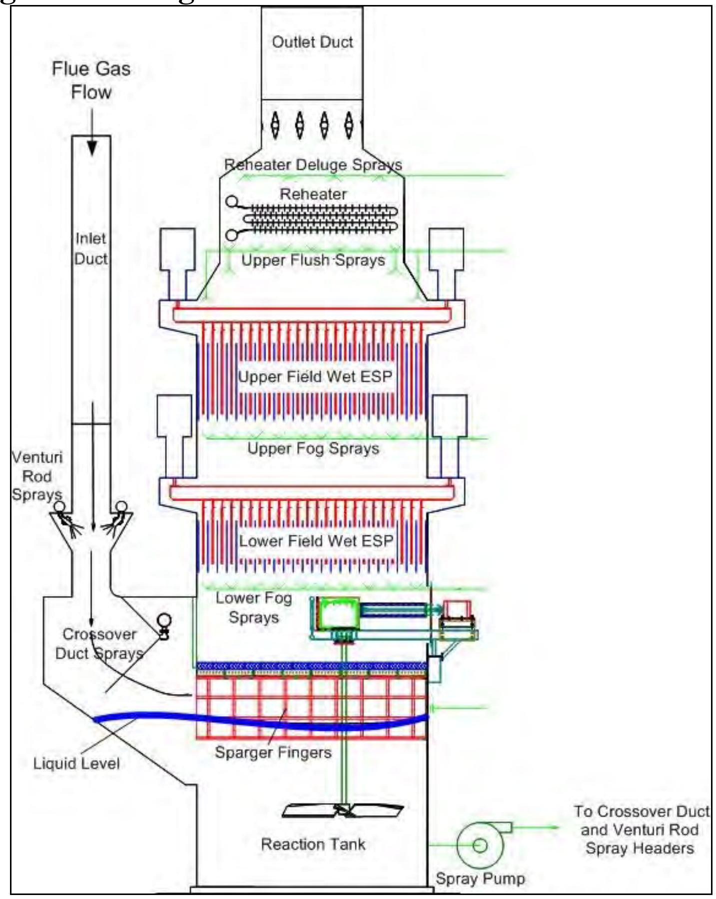
Sherco 1 and 2 currently utilize low NO_X burners (LNB), separated and close coupled overfire air (OFA) systems, and combustion optimization systems to reduce NO_X emissions. These systems were installed on Sherco Units 1 and 2 as part of our efforts to reduce NO_X emissions at the facility for several federal programs.

LNB control the formation and emission of NO_X through staged combustion. LNB control and balance the fuel and airflow to each burner, and control the amount and position of secondary air in the burner zone. The OFA systems work by reducing the excess air in the burner zone, thereby enhancing the combustion staging effect and further reducing NO_X emissions. To further reduce NO_X emissions and to optimize combustion, "burner balancing" is used to properly balance the amounts of coal and air that enter the furnace. This entails monitoring and adjusting burners in real time, so that the fuel-to-air ratio is equalized across the boiler.

3. *Sulfur Dioxide (SO_2)*

Both units currently use WFGD systems to control SO_2. The WFGD systems historically achieved 75% removal. The Company is currently in the process of retrofitting the current venturi scrubber/WESP modules with sparger tubes to further increase SO_2 removal from these units. These sparger tubes are being installed within the existing modules so that the incoming flue gas is channeled through the sparger tubes, forcing the flue gas to bubble through the slurry in the reaction tank. This increased contact time of the flue gas with the slurry results in greater levels of SO_2 removal. Figure 4.1 is a diagram of a scrubber module with sparger tubes.

Figure 4.1: Diagram of 1 of 12 Scrubber Modules Per Unit



4. *Mercury (Hg)*

In 2009, the Company submitted its plan to install mercury controls in accordance with the Minnesota Mercury Emission Control Act of 2006. This plan has two parts: 1) continue to study and test new mercury control technologies, while monitoring the development of potential federal environmental regulations; and 2) install a sorbent injection system at Sherco 1 and 2 by no later than December 31, 2014, if no other mercury control technologies are determined to be more advantageous, considering mercury control and cost. We have completed full-scale testing of mercury control technology on Units 1 and 2 to validate that the sorbent injection system, using activated carbon as the sorbent, will effectively remove mercury from Units 1 and 2. We are continuing to evaluate alternate control technologies, but, absent the identification of a superior alternative in the immediate future, we plan to complete the installation of the sorbent injection system by December 31, 2014.

5. Ash

The Sherco Plant uses a variety of methods to manage its coal ash. Fly ash from Units 1 and 2 is transported to lined ponds designed and permitted for permanent disposal. The ponds are lined with clay and/or High Density Polyethylene (HDPE) membranes and are operated under permits issued by the state. New ponds are constructed as the old ponds are filled to capacity. When filled, the disposal ponds are capped with a Linear Low Polyethylene (LLPE) membrane and dewatered. This provides for permanent disposal in what is essentially a dry disposal facility after dewatering is complete. Post closure requirements include an engineered cap and vegetation, long-term maintenance, and ongoing groundwater monitoring until such time as the ponds are fully dewatered.

Bottom ash collected from Sherco Units 1 and 2 is hydraulically transported to a clay-lined pond that temporarily stores the ash. The ash is periodically removed by mechanical dredging. Most of the bottom ash is beneficially used onsite as construction material. A small percentage that is not reused is disposed of in the Unit 1 and 2 ponds.

The U.S. Environmental Protection Agency (EPA) inspected the Sherco ponds in fall 2009 and awarded the facility its highest possible rating for design and structural integrity.

6. Water

The Sherco Plant uses water from three different sources: Mississippi River, groundwater, and storm water. The plant generates numerous different wastewater streams and about 90% is treated, stored, and reused onsite within various plant processes. The only plant process water that is discharged to the Mississippi River is from the cooling tower.

The closed-cycle cooling system withdraws water from the Mississippi River and continuously recirculates that water through the condensers and cooling system in a process that reuses the water six or seven times before eventual discharge. The condenser cooling water is treated with sodium hypochlorite and sodium bromide to control the microbiological growth in the system and sulfuric acid is added for pH control and to reduce scaling. As the cooling water passes over the cooling towers several times, some is lost through evaporation, which requires the addition of make-up water from the river to maintain water levels in the system. This continuous evaporation of water in the system, coupled with the constant replenishment from the river, eventually concentrates total dissolved and suspended solids to levels six to 10 times that of the source water. To maintain water quality in the cooling towers and condensers, some water from the cooling towers is continuously bled from the system (referred to as blow-down) to a holding pond to be treated before being discharged to the river. The holding pond is designed for at least a 24-hour residence time to reduce total residual chlorine in the discharged water.

Process wastewater is also generated at Sherco by sluicing ash to the scrubber solids ponds and from various other plant service water systems. As discussed above, fly ash from Units 1 and 2 is hydraulically transported to the scrubber solids pond. The water is then returned to the plant for reuse. Bottom ash from Units 1 and 2 is similarly sluiced to the bottom ash pond. Excess bottom ash transport water is decanted to the recycle basin for reuse. The system of plant drains also discharges to the recycle basin where it is collected for reuse. All water used to manage ash is recycled for use in the plant's industrial processes. Under normal operating conditions there is no discharge of process wastewater from the site, other than cooling tower blow-down.

B. Emissions Performance

Our investments in pollution control equipment on Sherco 1 and 2 have resulted in substantial quantifiable emissions reductions. Figure 4.2 shows the long-term emissions trends for PM, NO_X, and SO_2. The projected emissions reflect these units achieving the emission rate limits included in our Administrative Order with the Minnesota Pollution Control Agency (MPCA) beginning January 1, 2015. These limits are less than or equal to 0.12 pounds SO_2 per million British Thermal Unit (lb/mmBTU) and less than or equal to 0.15 lb NOx/mmBTU.

Figure 4.2: Sherco 1 and 2 Emissions Trend, 2005-2020 (PM, NO_X, and SO_2)

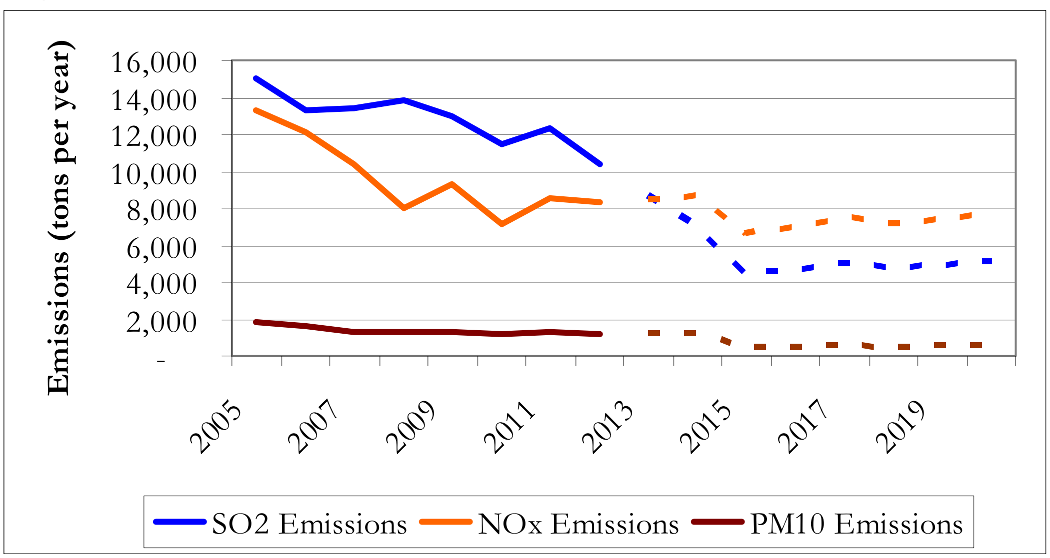
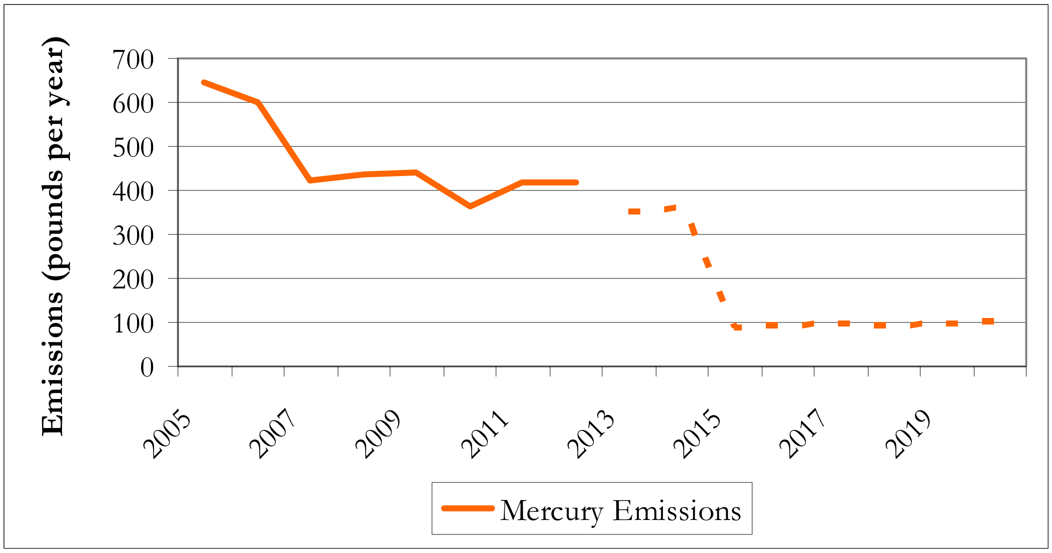


Figure 4.3 shows the long-range trend for mercury emissions. The projected mercury emissions reflect these units achieving an emission rate of less than 1.0 pound of mercury per terra BTU beginning in 2015.

Figure 4.3: Sherco 1 and 2 Emissions Trend, 2005-2020 (Mercury)



Chapter 5. Environmental Regulation

Sherco Units 1 and 2 are subject to numerous environmental rules and regulations designed to protect human health and the environment. The EPA regulates multiple activities to protect air, water and land resources. For example, the EPA implements air quality programs to reduce air emissions from many types of sources to the levels needed to meet health-based air quality standards. Through periodic reviews, EPA has made these standards significantly more stringent over time in response to studies on the health effects of various air pollutants.

Sherco Units 1 and 2 are well prepared to comply with existing and developing air, water and land regulations, including EPA's Mercury and Air Toxics Standards (MATS). There are two regulatory areas that could require additional pollution control equipment beyond what is currently installed or being installed, including:

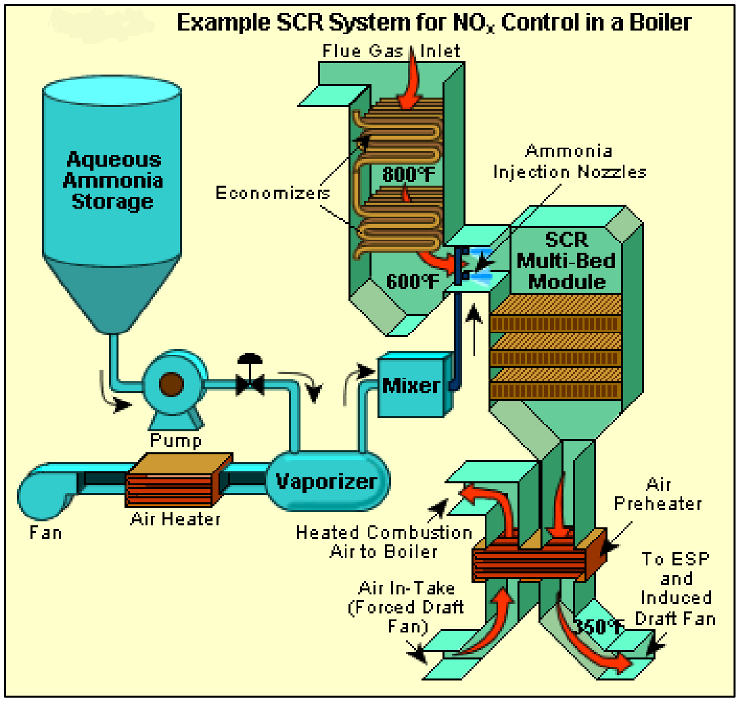
- National Ambient Air Quality Standards (NAAQS) for ozone or PM; and
- Regional Haze Rule or "reasonably attributable visibility impairment" (RAVI) visibility regulations, which focus on emissions of SO_2, NO_X and PM.

We briefly discuss these developments below, as well as uncertainties surrounding the future direction of carbon regulation. Appendix A provides a complete discussion of the known and anticipated environmental rules and regulations and how they may impact operation of Sherco 1 and 2.

A. Potential Future Investments Required for Environmental Compliance

Sherco Units 1 and 2, with their upgraded particulate matter controls and the scrubber upgrades that will be completed by 2015, are expected to have emission performance for PM and SO_2 equivalent to current BACT for retrofit units. The combustion controls, low NO_X burners and overfire air controls put on the units several years ago have substantially reduced NO_X emissions. As a result, the only additional control equipment that could reasonably be anticipated to be required for the units is the addition of Selective Catalytic Reduction (SCR) technology, which would further reduce NO_X emissions. In SCR systems, vaporized ammonia injected into the flue gas stream acts as a reducing agent, achieving NOx emission reductions when passed over a catalyst. The NO_X and ammonia react to form nitrogen and water vapor. Figure 5.1 is a diagram of an SCR system.

Figure 5.1: Diagram of Example SCR System



Further NO_X emission reductions might be required if Minnesota has areas that do not meet the ozone NAAQS as it may be revised in 2014, or falls into nonattainment for particulate matter. Once EPA adopts or revises a NAAQS, states are required to monitor their air quality to determine whether the ambient air in any areas of the state fail to meet the NAAQS. States analyze their air monitoring data and submit to EPA their designations of parts of the state as in attainment or nonattainment of the NAAQS. EPA then reviews the state's proposal and determines the final area designations. Typically, this process is completed two years after a NAAQS revision.

If any areas within Minnesota were to be classified as being in nonattainment, the Minnesota Pollution Control Agency (MPCA) would have to develop a State Implementation Plan (SIP) to bring the area back to attainment. When developing the SIP, the MPCA would need to address point source emissions inside of the nonattainment area, which could include Sherco 1 and 2, as well as mobile source emissions and other sources.

EPA is working to revise the ozone NAAQS and is expected to propose a new standard in 2013 with expectations that it will be finalized in 2014. According to the ozone NAAQS implementation schedule shown in Appendix A, further NO_X reductions might be required in the early to mid 2020s, if Minnesota is designated as being in nonattainment for ozone.

Similarly, on January 15, 2013, EPA finalized NAAQS for both coarse and fine particulate matter. EPA is expected to designate non-compliant locations by December 2014. We believe Minnesota will remain in attainment for $PM_{2.5}$ based on the latest revisions to the NAAQS described above. However, according to the MPCA's 2013 Report to the Legislature,[9] despite overall improvements in air quality, Minnesota is at some risk of exceeding the federal standards for both ozone and $PM_{2.5}$. If installation of SCRs were to be found necessary to address any future nonattainment of the particle NAAQS, the compliance date would be in the mid-2020s.

The visibility programs focus on reducing emissions of PM, SO_2 and NO_X as pollutants that can result in visibility impairment in national parks and wilderness areas. Based on the current level of controls for PM and the upgraded controls for SO_2 at Sherco 1 and 2, it is not expected that any further reductions would be required due to continued implementation of visibility programs. However, should further NO_X reductions be required at some point in the future, SCR systems on one or both units could be installed. The time when additional controls may be required for Sherco Units 1 and 2 for visibility regulation purposes is difficult to assess due to ongoing litigation. Based on our analysis, the range of time within which SCR systems might be required would be 2018-25. Further discussion is included in Appendix A.

As discussed later in the study, our model assumes early implementation of SCR systems in 2018 and 2019, and later implementation in 2024 and 2025 to address the range of potential timelines for additional pollution control. The addition of an SCR system on one of the units would take approximately four years to receive the necessary regulatory approvals and install and test the system for operation. Due to the scheduling of major overhauls for the units, addition of an SCR on the second unit is expected to take five years.

Additionally, in the event that one or both of the units is repowered or replaced with natural gas capacity, the new natural gas-fired unit would be required to complete a full permitting and regulatory approval process, install BACT, and comply with existing and developing air, water and land regulations.

B. Carbon Dioxide Regulation

The most significant environmental policy affecting the future of coal-fired power plants (including Sherco Units 1 and 2) is also the most uncertain. Today, it is

[9] The electronic version is available on the MPCA web site at *www.pca.state.mn.us/yhizb6a*.

unknown what kind of greenhouse gas (GHG) policy will ultimately be adopted or how that that policy will affect existing coal-fired power plants like Sherco 1 and 2. For example, a strict stack-by-stack approach could reduce future operation of the units, while a more flexible portfolio-based approach could potentially allow operations to continue at Sherco 1 and 2 with emissions reductions achieved through other means.

The EPA has already started regulating carbon dioxide (CO_2) under the CAA, but there is also the possibility of a broader federal legislative policy that could establish GHG reduction targets. In addition, state legislatures and other policy makers are considering their own GHG proposals. Consequently, at this time, the impact of CO_2 regulation on future operation of Sherco Units 1 and 2 is unclear. As discussed below, the Commission requires utilities to incorporate a carbon proxy cost in resource planning analyses to recognize the eventual likelihood of some form of carbon regulation. The Company uses the Commission-approved carbon proxy cost range in this study.

1. *Background*

CO_2 is a greenhouse gas that traps the sun's energy in the atmosphere, resulting in an overall warming of the Earth's climate. CO_2 is an inevitable consequence of the combustion of fossil fuels, and, as such, the concentration of CO_2 and other GHGs in the atmosphere has increased as global use of fossil fuels as an energy source has grown. To address climate change, many policymakers have sought to reduce CO_2 emissions through various legislative policy proposals. Over the last several years, some policymakers have turned to EPA regulation under the CAA as the primary vehicle to reduce emissions of CO_2.

During the first four years of the Obama administration, Congress attempted to pass comprehensive climate and GHG legislation. Although the U.S. House of Representatives passed a nationwide cap and trade program proposal (H.R. 2454) in 2009 that would have required a 17% emissions reduction from 2005 levels by 2020 for utilities and other major emitters, the Senate did not follow and that proposal did not become law. After the elections of 2010 and 2012, Congress expressed stronger opposition to cap and trade and other climate legislation. As a result, national climate legislation remains unlikely in the near term.

Nevertheless, President Obama continues to express interest in moving toward more sustainable forms of energy to address climate change. During his second inaugural speech on January 21, 2013, President Obama stated, "We, the people, still believe that our obligations as Americans are not just to ourselves, but to all posterity. We will respond to the threat of climate change, knowing that the failure to do so would betray our children and future generations."

Some political groups are advocating a direct federal tax on the carbon content of fossil fuels (*i.e.* coal, oil and natural gas) as a means to reduce carbon emissions while generating tax revenue. Other carbon reduction policies could include a clean energy standard, which would be similar to a renewable standard but would also include (in addition to renewable energy) other clean and low-carbon sources, such as natural gas, nuclear power and "clean coal" technology with carbon sequestration. Market-based proposals such as cap-and-trade programs remain a possibility, but are considered unlikely in the short term.

2. *GHG Regulation under the CAA*

EPA has already begun regulating GHG through the CAA. In 2009, in response to the U.S. Supreme Court's decision in *Massachusetts v. EPA*[10] the EPA issued its "endangerment finding" that GHG emissions endanger public health and welfare and that emissions from motor vehicles contribute to the GHGs in the atmosphere. The EPA also promulgated permit requirements for GHGs for large new and modified stationary sources, such as power plants. In December 2010, the EPA announced a settlement with several states and environmental groups to begin preparing regulations of emissions from both new and existing steam EGUs, such as coal-fired power plants, under Section 111 of the CAA. The EPA has proposed regulations for new sources and is developing regulations for existing sources.

Although several businesses and business organizations have challenged EPA's regulations, on June 26, 2012, the U.S. Court of Appeals for the District of Columbia Circuit upheld EPA's determination that GHGs can be regulated under the Clean Air Act.[11] As a result of this decision, EPA's development of GHG regulation will likely continue.

a. New Source Review

Starting January 1, 2011, EPA began regulating GHGs under the New Source Review (NSR) Program of the CAA. EPA now requires a review of GHG emissions for air permits issued to new power plants that are major sources, or to existing power plants that undertake major modifications. This review, known as the BACT review, is required before the plant can receive an air permit. EPA requires BACT review on all

[10] 549 U.S. 497 (2007).
[11] *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102 (D.C. Cir. 2012).

new plants emitting at least 100,000 tons per year of CO_2 emissions and modified facilities increasing their CO_2 emissions by at least 75,000 tons per year.[12] The GHG BACT review is a process that involves identifying a set of options for reducing GHG emissions, analyzing those options, then choosing the best available option based on energy, environmental and economic reasons.

b. New Source Performance Standard

In April 2012, EPA proposed a New Source Performance Standard (NSPS) under section 111(b) of the CAA for new power plants.[13] This NSPS would require all new coal- or gas-fired generating plants (excluding peaking plants) to meet a CO_2 emission rate achievable today only by natural gas combined cycle plants. This proposed GHG NSPS acts as a ban on new coal-fired plants unless they utilize carbon capture and sequestration to capture half or more of their emissions. Today, carbon capture and sequestration is not a commercially available technology. In its proposal, EPA recognizes this fact and, as a result, the proposal would allow construction of a coal-fired plant without carbon capture provided the owner or operator commits to installing capture and sequestration technology within ten years. Despite this provision, it is unlikely that any coal plant developer would risk the substantial capital required to build a coal plant on the assumption that capture and sequestration technology would develop over the next decade. If adopted as proposed, the rule would not allow additional coal to be considered in the future following any decision to retire an existing coal facility. The proposed rule is currently being challenged. As a result, the timing of its finalization and its final requirements are not known. On June 25, 2013, the Obama administration announced plans to re-propose this rule by September, 30, 2013. The timing of the final rule and its final requirements are not known.

c. Existing Power Plants

In its 2010 settlement with the environmental community, EPA also committed to regulate CO_2 emissions from existing power plants. The EPA originally stated that it would propose GHG rules for existing power plants under Section 111(d) of the CAA and finalize these rules in 2012. The Obama Administration announced on June 25, 2013 its plan to issue a proposed rule for existing power plants by June 1, 2014, with a final standard by June 1, 2015. The proposal is expected to include a requirement that State Implementation Plans (SIP) be submitted to EPA by June 30,

[12] *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule*, 75 *Fed. Reg.* 31514 (June 3, 2010).
[13] *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, 77 *Fed. Reg.* 22392 (April 13, 2012).

2016. Compliance deadlines would likely be within three to five years of EPA's adoption of the new existing power plant standard or a state's SIP that implements the standard. The Administration encourages working directly with the states to build upon current efforts, provide flexibility, and take advantage of a wide variety of energy sources and technologies. Given Congress' likely opposition to climate legislation, EPA's Section 111(d) program is likely to be one of the principle vehicles for the Obama Administration's efforts to address climate change.

Section 111(d) of the CAA grants EPA authority to establish "guidelines" for reductions of certain emissions from existing sources like power plants. It is not certain how EPA will develop its guidelines. For example, in light of the lack of a commercially viable capture and sequestration technology, EPA may establish emission limits for specific types of power plants (*i.e.* stack-by-stack) based on achievable efficiency improvements. Regardless, once the stack-by-stack standards are established, the options for state implementation of the guidelines are broad. Unlike other sections of the CAA (which set mandatory, stack-by-stack targets), Section 111(d) contemplates significant state flexibility in meeting these guidelines and allows states to develop their own plans for compliance. Xcel Energy believes that Section 111(d) allows states to develop alternative plans that incorporate renewable portfolio standards, demand-side management, emission reduction programs such as MERP, and other clean energy programs. We also believe that is imperative for EPA to recognize in its proposal clean energy initiatives already underway. Our customers have paid for these initiatives and if they are not considered in the "baseline assumptions," then customers will have to pay for additional reductions that do not reflect those already achieved.

Other advocacy groups have proposed alternative proposals for Section 111(d) regulations. The National Resources Defense Council (NRDC) has provided a proposal that would cut existing power plant emissions 26% by 2020 from 2005 levels.[14] The proposal would require emissions limits for each state that would need to be met in 2020. NRDC contemplates that states could comply through the use of a credit trading program similar to a cap and trade program. Based on the technology available today, a state could not meet the emission limits solely by making changes to its coal-fired plants; it would have to make significant reductions by some combination of switching to natural gas-fired generation and adding more renewable energy and energy efficiency.

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[14] www.NRDC.org/policy.

3. Strategies to Reduce Carbon Emissions

Because the policies for CO_2 regulation are not established, we do not know whether utilities will have the flexibility to make system-wide carbon reductions based on the most cost-effective strategies, or whether reductions will have to be made via a stack-by-stack approach. Under a stack-by-stack approach, Sherco Units 1 and 2 may be able to slightly reduce carbon emissions through heat rate and other efficiency improvements. While carbon capture and sequestration technology may be available in the future for coal-fired power plants, the geologic formations near Sherco do not allow for sequestration of CO_2, making it likely unviable for Sherco 1 and 2.

Xcel Energy advocates for a systematic approach based on the clean energy programs discussed above. This approach results in more significant emission reductions at far lower cost and could include emissions reduction strategies like making efficiency improvements at fossil fuel-fired plants; adding more renewable energy to the system; and increasing customer demand side management programs. Utilities can also retire coal-fired (or inefficient gas-fired) power plants and replace them with more efficient natural gas combined cycle plants or a combination of natural gas and renewables. Combined cycle plants have a CO_2 emission rate that is approximately half of that of typical pulverized coal plants. If the applicable carbon policy will allow the use of clean energy programs, such as renewable portfolio standards and demand-side management, Sherco Units 1 and 2 may be largely unaffected by a carbon policy, as Xcel Energy pursues emissions reductions through other strategies.

4. Carbon Proxy Cost

To address carbon policy uncertainty when making future resource decisions, Minn. Stat. § 216H.06 requires the Commission to establish an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation, and update the estimates annually following informal proceedings. The carbon proxy cost is intended as a planning tool to estimate how future regulation of CO_2 emissions will affect the cost of generating electricity. The Commission's November 2, 2012 Order in Docket No. E999/CI-07-1199 maintained the estimate of the range of likely costs of CO_2 regulation at between \$9 and \$34/ton of CO_2 for 2012 and 2013. Utilities must apply the range of CO_2 values in their resource planning as of 2017.

Chapter 6. Strategist Modeling Inputs and Assumptions

A. Overview

The Strategist planning model simulates the operation of the NSP System under different future scenarios and tests the model results under a range of input assumptions. Strategist is used in resource planning to estimate the cost of various resource expansion plans, to evaluate specific capacity alternatives, and to measure the potential risks of new environmental legislation and other policy scenarios. Each model run produces total system cost and emissions results, which are analyzed across the various scenarios. In this analysis, Strategist is used to evaluate the cost of retrofitting Sherco 1 and 2 with new pollution control equipment to reduce NO_X emissions and the alternative of retiring the units and replacing with combinations of new natural gas generation, renewable energy, and conservation.

The Strategist analysis is organized into three parts:

- Reference Case Assumptions
- Scenarios and Sensitivities
- Model Output

The Reference Case is the starting point from which the various life cycle management strategies are built. The Reference Case contains the cost and performance inputs for all of our generation resources, load growth projections, fuel cost forecasts, and expected cost to construct new generation resources. The Reference Case assumes that Sherco 1 and 2 continue current operations through 2040 without the addition of new environmental controls beyond what is already in progress. Structuring the Reference Case this way allows for clear comparison of each scenario's incremental cost and impact to customer rates. The Reference Case includes our estimate of the necessary costs to continue reliable operations of the unit, including operation and maintenance expenses, and capital investments. It also incorporates known policy commitments, such as the Renewable Energy Standard and energy conservation goals.[15] Per the Commission's Order, a CO_2 cost of \$21.50/ton is included in the Reference Case starting in 2017.[16] We ran an alternative Reference Case without the CO_2 cost to satisfy the North Dakota Public Utilities

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[15] Minn. Stat. §216B.1691 sets the renewable energy objectives of achieving 25% of retail sales by 2016 and 30% by 2020. Minn. Stat. §216B.2401 establishes a goal of achieving annual savings of 1.5% of retail sales. The Reference Case assumes savings of 1.5% of sales through 2015 and 1.4% thereafter to reflect an expected decline in achievable savings.

[16] Docket No. E999/CI-07-1199. Order Establishing 2012 and 2013 Estimate of Future Carbon Dioxide Regulation Costs. November 2, 2012.

Commission's request. To the Reference Case, we add pollution control scenarios and retirement scenarios.

Scenarios establish the high level options for the future of Sherco 1 and 2, specifically whether one or both units continue to operate and if retired, what resources replace them. For this analysis, the scenarios address:

- Timing of additional pollution control equipment at one or both of the units;
- Timing of retirement for one or both of the units; and
- Replacement options that will maintain system reliability.

To model the cost of NO_X pollution control equipment, we add to the Reference Case the capital investment needed to install the equipment and ongoing costs to operate and maintain it. With the installation of SCRs, we make the assumption that the units will continue to operate until 2040. In retirement scenarios, the Sherco units are decommissioned either in 2019 and 2020, before their current fully depreciated dates, or in 2024 and 2025, and replaced with a variety of different generation alternatives. Strategist tracks fuel consumption, plant emissions, and calculates total annual system costs. Annual costs are discounted to derive a single present value of revenue requirements (PVRR) for each scenario.

We conduct sensitivity analysis to test the impact of important input assumptions on the PVRR results. The sensitivity analysis changes a single input variable at a time and estimates different PVRR values for each scenario. We conducted sensitivity tests for load, fuel prices, CO_2 costs, and equipment costs. In total, we ran 23 different scenarios and 26 sensitivities or 598 Strategist simulations for this analysis. These are summarized in Appendix B.

As required by the Commission's Resource Plan Order,[17] the Company also analyzed sensitivities that include a wide range of fuel prices and meet the 15% by 2015 and 30% by 2025 GHG goals established by the Minnesota Legislature. Achievement of the 80% by 2050 GHG goal is unaffected by our Sherco LCM strategy as both units will likely be retired by 2050 regardless. The Company also included as sensitivities the full range of CO_2 and criteria pollutant externality values developed by the Commission. The Company also provides cost estimate impacts from federal CO_2 externality values and for non-carbon air pollutants, values derived from a National Research Council study. Similar to the externality values established by the Minnesota Commission, the cost of CO_2 has the largest impact on our analysis and the costs applied to the other effluents are much less significant.

[17] Docket No. E002/RP-10-825. Order Establishing Procedural Schedule and Filing Requirements. November 30, 2012.

At the request of Environmental Intervenors, the Commission also asked us to investigate the use of externality values in the development of Regulatory Impact Assessments associated with EPA rulemaking and incorporate them if possible. We investigated the use of externality values in several of the most recent EPA rulemaking dockets and found no values that could be applied to emissions in the same way the Commission's environmental values are applied. We then asked Environmental Intervenors for their thoughts on a source of externality values we should consider and were referenced to a report from the National Research Council. While the NRC study is only one of a broad range of externality investigations in the literature, we used it to test the sensitivity of our analysis to its externality values. Appendix C provides a more in-depth discussion of the results of sensitivity testing, the difficulties we encountered as we reviewed EPA Regulatory Impact Assessments, as well as the limitations of the application of the NRC study.

The results of the simulations are summarized in Strategist Output spreadsheets. These spreadsheets provide several key results, such as total system energy mix, air emissions, fuel consumption, and total annual costs. The spreadsheets also contain detailed information on each individual generation resource in the Strategist model. The total system costs are reported as the net present value of revenue requirements or "PVRR." This value is the sum of all operating, depreciation, return on rate base, and tax costs discounted back to 2013 using the Company's most recently authorized weighted after tax cost of capital.

Rate impacts are also derived from the Strategist output simulation results. This rate impact is calculated by dividing the difference between the annual revenue requirements for the specific sensitivity, minus the same for the Reference Case, divided by annual forecasted sales. The Strategist model tracks fuel as a separate component, allowing the rate impact to be provided in terms of both rate base and fuel clause components.

B. Reference Case Assumptions

As noted above, the Reference Case is the foundation on which the other scenarios and sensitivities are built. Below we discuss the main assumptions of the Reference Case. Additional details on the modeling inputs used in the Reference Case are provided in Appendix D.

1. Load Forecast

The Company used the load forecast developed in spring 2013. This forecast is planned to be the basis for our Resource Plan filing in 2014. From 2013 to 2040, the average growth rate for total energy is 0.60%, and the average growth rate for peak demand is 0.74%. The load forecast incorporates a conservation target of 1.5% of sales from 2013-2016 and 1.4% of sales thereafter. We assume load management of 985 MW in 2013 increasing to 1,045 MW in 2019, for a long term average 1,039 MW. The analysis includes sensitivities on the growth rate of energy and demand, as well as a sensitivity using the forecast from our most recent Resource Plan.

2. *Natural Gas and Market Energy Prices*

We updated the price of natural gas and market energy in March 2013. The near term prices are based on published NYMEX prices. In the longer term, the prices are a simple average of forecasts from three independent forecasting firms. The natural gas prices listed below are for the Ventura distribution hub. Each natural gas generating unit in the Strategist model will include a small delivery charge from Ventura to the plant site. The Strategist model includes a simulation of energy purchases from the MISO market. In each hour of the simulation the model has the option to purchase energy from the MISO market if it is economically efficient to do so. Hourly purchases are limited by a 1,000 MW energy import maximum. Strategist is restricted from selling energy into the MISO market to ensure that new plants are not constructed based on the speculative assumption that their energy could be sold into the market at a profit.

Table 6.1: MISO Market Prices[18] and Natural Gas Forecasts

	On ($/MWh)	Off ($/MWh)	Ventura Gas ($/MMBtu)		On ($/MWh)	Off ($/MWh)	Ventura Gas ($/MMBtu)		On ($/MWh)	Off ($/MWh)	Ventura Gas ($/MMBtu)
2013	$34.54	$21.08	$3.87	**2026**	$63.88	$40.82	$7.27	**2039**	$83.18	$57.06	$9.64
2014	$35.03	$20.52	$4.15	**2027**	$64.77	$41.44	$7.44	**2040**	$84.78	$58.15	$9.82
2015	$37.27	$22.74	$4.28	**2028**	$65.92	$42.30	$7.60	**2041**	$86.40	$59.27	$10.01
2016	$39.59	$25.58	$4.41	**2029**	$68.05	$45.00	$7.82	**2042**	$88.06	$60.40	$10.20
2017	$43.17	$27.88	$4.62	**2030**	$69.85	$46.67	$8.01	**2043**	$89.74	$61.56	$10.40
2018	$47.62	$31.46	$4.96	**2031**	$71.11	$47.41	$8.16	**2044**	$91.46	$62.74	$10.60
2019	$51.56	$34.40	$5.33	**2032**	$72.79	$49.19	$8.33	**2045**	$93.21	$63.94	$10.80
2020	$52.54	$33.52	$5.67	**2033**	$73.81	$50.34	$8.53	**2046**	$95.00	$65.16	$11.01
2021	$55.15	$35.17	$5.93	**2034**	$75.51	$51.38	$8.72	**2047**	$96.82	$66.41	$11.22
2022	$56.85	$36.53	$6.19	**2035**	$77.10	$52.89	$8.93	**2048**	$98.67	$67.68	$11.44
2023	$58.79	$37.36	$6.61	**2036**	$78.58	$53.90	$9.10	**2049**	$100.56	$68.98	$11.66
2024	$60.18	$38.51	$6.83	**2037**	$80.09	$54.93	$9.28	**2050**	$102.49	$70.30	$11.88
2025	$62.76	$39.86	$7.06	**2038**	$81.62	$55.99	$9.45				

3. *Coal Prices*

Coal price forecasts are developed using two major inputs: current contract information combined with long range estimates of future commodity costs and

[18] The MISO market prices are based on the NSP.NSP commercial pricing node.

delivery charges. Typically, coal is purchased by contract for a one to five year term; these actual contract prices are combined with forecasts from Wood Mackenzie, JD Energy, and John T. Boyd Company. To the basic commodity costs we add estimates of transportation charges, SO_2 costs, freeze control, and dust suppressant, as required. The analysis assumes a coal price of $2.25/mmBtu in 2013 escalating at an average of 2.15% per year.

4. *CO_2 Emissions*

The Reference Case includes a cost of $21.50/ton of CO_2 emitted by fossil fuel generation beginning in 2017 and escalating at 2.3% per year. This is the midpoint of the Commission-approved range of $9 to $34/ton. The endpoints of this range will be run as sensitivities. To facilitate the requests of the North Dakota Commission staff, we also conduct all scenarios and sensitivities without any costs applied to CO_2 emissions.

5. *Costs at Sherco*

The Reference Case assumes that Sherco 1 and 2 will continue to operate until 2040 without installation of any new pollution control equipment. It includes our estimate of the necessary costs to continue reliable operations of the units, including O&M expenses and capital investments. The primary operations assumptions are summarized below.

- Maximum Capacity[19] – Unit 1: 681 MW, Unit 2: 682 MW
- Average Heat Rate – Unit 1: 10.3 mmBtu/MWh. Unit 2: 10.5 mmBtu/MWh
- Average Maintenance Requirement – 2.6 weeks/year
- Average Forced Outage Rate – 4%
- Emission Rates (lbs/MWh)[20]
    - Unit 1 – CO_2: 2260, SO_2: 1.07, NO_X: 1.60
    - Unit 2 – CO_2: 2210, SO_2: 1.07, NO_X: 1.61
- Fuel – $2.25/mmBtu in 2013 escalating at an average of 2.15%
- Variable O&M - $1.06/MWh in 2015 escalating at 2.39% (includes activated carbon for mercury control)
- Fixed O&M - $21 million/year for each unit ($42 million total) escalating at 2.45%
- Ongoing Capital 2013-2040 – Unit 1: $648 million, Unit 2: $616 million

[19] This is the maximum capacity net of plant usage and is based on recent capacity testing.
[20] These emission rates are based on expected rates in 2014 after the sparger tube project in the wet scrubbers is complete.

- Decommissioning[21] - $1.5 million/year for each unit.
  - 2013-2040 total decommission accrual – Unit 1: $41.5 million, Unit 2: $41.5 million

The forecasted cost to cover regular operations and maintenance of Units 1 and 2 is comprised of labor, materials, consumables, chemicals, and other items directly used by each unit, as well as an allocation of resources utilized by all of the units at the plant. The forecasted cost of regular O&M increases significantly in 2015 due to the use of activated carbon to control mercury emissions on Units 1 and 2.

The capital investment required to meet currently applicable environmental regulations are included in the Reference Case forecast for Units 1 and 2. This includes the following projects to be completed in the 2013-2015 timeframe:

- FGD Scrubber Sparger Modifications,
- WESP Power Supply Replacement,
- WESP Electrode Replacement,
- Activated Carbon Injection Mercury Control, and
- Boiler Combustion Optimization Controls Replacement.

Throughout the life of these two units, capital investments have been and will continue to be made to retain the reliability, production performance, and environmental performance of the units. Units 1 and 2 each have approximately 25,000 discrete components. Each year a portion of components that cannot economically or practically be repaired are replaced or rebuilt as a capital investment.

Many of the major components on both units are original to the plant. Inspection and testing results for this equipment indicate that the majority will last for many more years before a capital investment is needed, but some will require capital investments in foreseeable future. In any event, these projects will undergo environmental regulation applicability review before they are completed.

6. *Long-Term Expansion Plan*

To develop the long term expansion plan, most units were modeled as retiring at their currently scheduled book life.[22] Retirements include the 500 MW King coal plant in

[21] In Strategist, decommissioning costs are incurred as yearly expenses during the operating life of the plant and accumulated until the end of life when they are needed.

[22] Blue Lake 1-4, Key City, and Granite City are small peaking facilities. These plants are currently at the end of their book depreciation lives. However, the Company plans to operate these units for a few more years.

2036 and our nuclear facilities in 2031 through 2035. This creates a substantial capacity deficit in future years. Strategist was allowed to pick from natural gas, coal, and nuclear capacity alternatives. Renewable alternatives were not included as optimization alternatives. Instead, specific levels of wind and solar were hard-coded into the model to reflect the need to meet RES requirements. The least cost plan that resulted from the Reference Case simulation was almost entirely natural gas. The expansion plan included continuation of our Solar*Rewards program and sufficient wind additions to meet our 30% by 2020 renewable energy standard. Table 6.2 summarizes the total retirements and additions that are included in the Reference Case. Figures 6.1 and 6.2 illustrate the timing of the resource additions and retirements.

Table 6.2: Resource Additions and Retirements

	Retirements	**Replacements**
Nuclear	1,610MW	0MW
Coal	2,075MW	0MW
Natural Gas	3,166MW	11,617MW
Oil	304MW	0MW
Renewables*	1,284MW	495MW
Other	102MW	0MW
Total	8,541MW	12,112MW

* Wind capacity credit is 12.9%

beyond the end of their book lives. These extensions were discussed in the Company's 2011-2025 Resource Plan. Sherco 3 was also assumed to operate through the end of the study period.

Figure 6.1: Resource Retirements

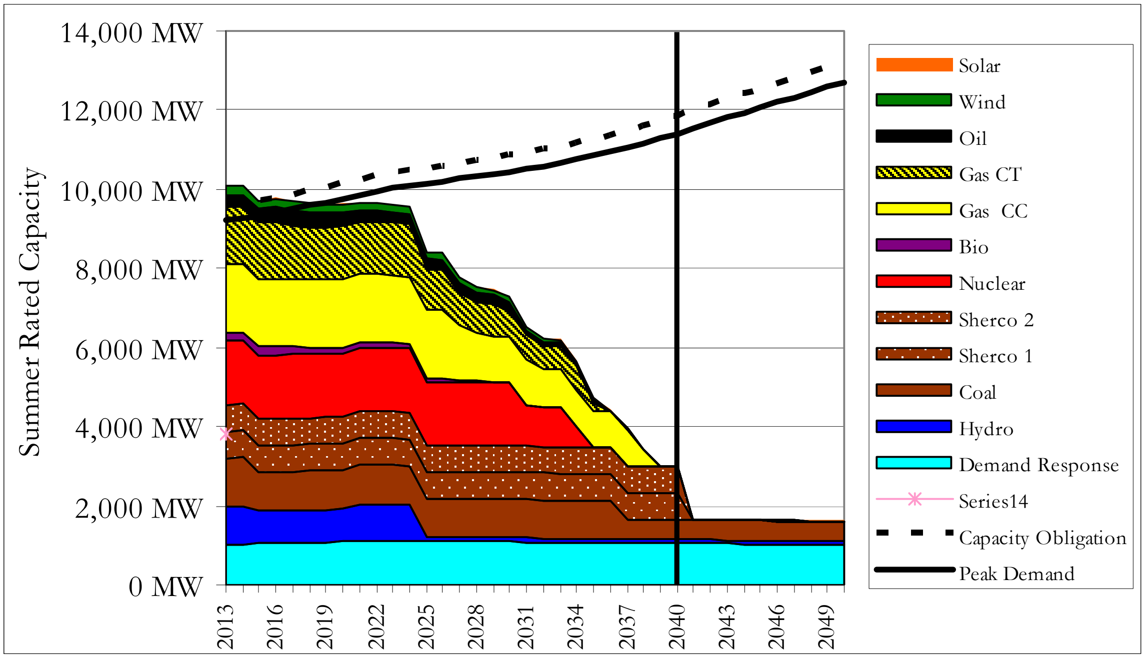


Figure 6.2: Resource Additions

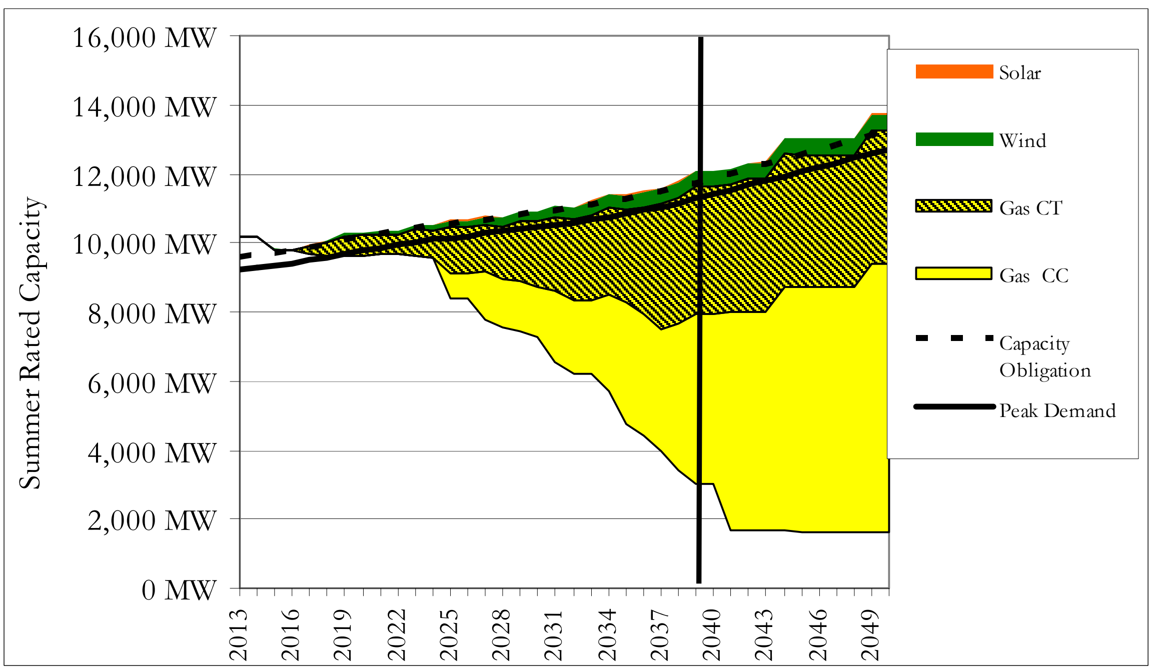
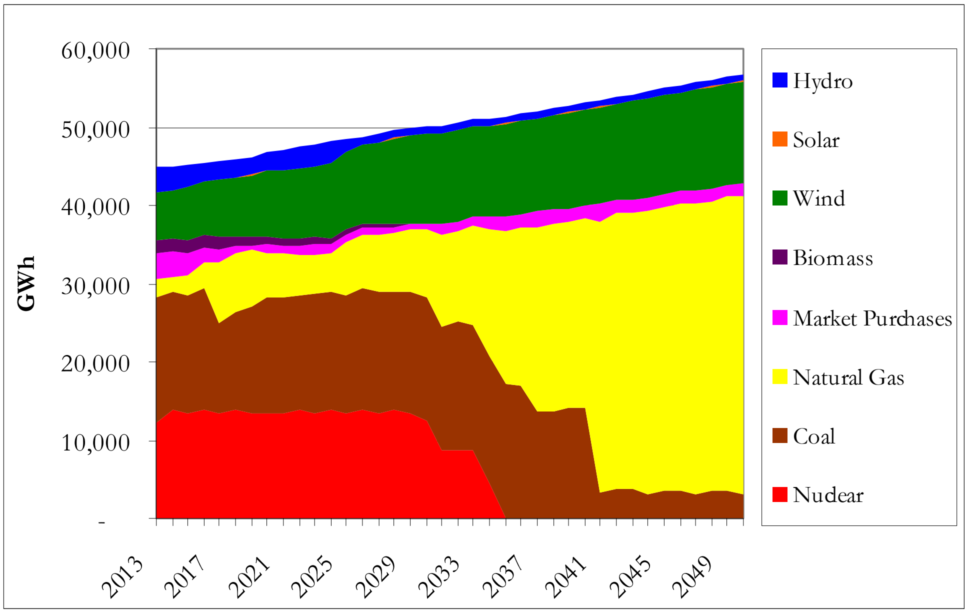


Figure 6.3 shows the Company's projected energy mix based on the Reference Case that was optimized in Strategist. This optimization was based on current cost assessment for various technologies and is for illustrative purposes only since many factors can influence our future fuel mix. As shown, the Reference Case retirements and additions change the characteristics of our energy portfolio, with most of the

future energy coming from natural gas resources with renewables maintaining a level of approximately 30%.

Figure 6.3: 2013-2050 NSP Total System Energy Mix



Chapter 7. Strategist Modeling Results

A. Overview

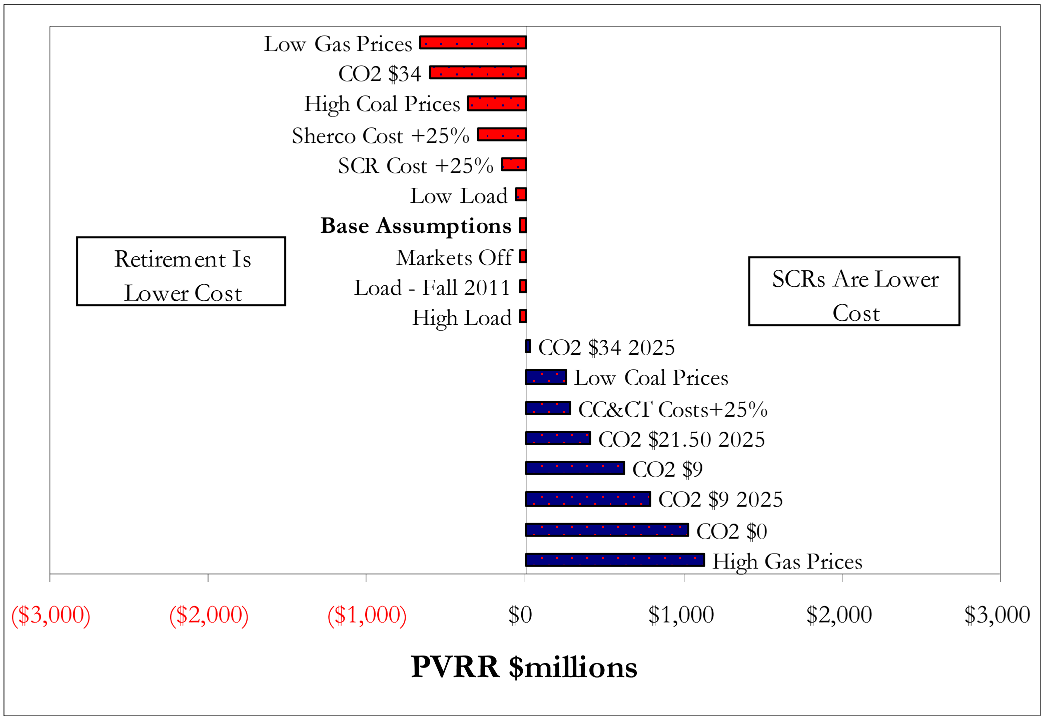
The Company ran a total of 598 simulations to evaluate the cost-effectiveness and emissions profile of various futures for Sherco Units 1 and 2. At a high level, the scenarios compare the relative costs of installing SCRs and continuing to operate one or both units with retirement of one or both units, given a number of assumptions about the future. Sensitivities are used to test the results against changes in assumptions.

The modeling results show that whether retirement or retrofitting is lower cost over the long term largely depends on the assumed price of carbon regulation. Figure 7.1 illustrates the relative PVRR impacts of retirement of Sherco 1 and 2 in 2019 and 2020 to the alternative of retrofitting the units with SCRs and continuing operations until 2040. The chart shows that under base assumptions (including \$21.50/ton CO_2 costs) the difference in total PVRR between the retirement and the SCR scenarios is negligible at only \$38 million PVRR. The chart also illustrates which input assumption sensitivities favor which strategy and how much they change the PVRR results. For example, the analysis shows that:

- Lower natural gas prices, higher CO_2 costs, higher coal prices, and higher-than-expected costs at the Sherco plant all favor retirement of the units.
- Higher natural gas prices, lower CO_2 costs or later implementation of CO_2 costs, low coal prices, and higher construction cost for new natural gas plants all favor installation of SCRs.
- Load sensitivities and the availability of market energy from MISO have little impact on the results.

PVRR results for all scenarios and sensitivities are provided in Appendix E, along with annual details for the 23 base assumption scenarios.

Figure 7.1: Summary of PVRR Results



Our analysis did not attempt to assign probabilities to the various futures. It simply evaluated the impacts should certain assumptions hold true. As discussed previously, there is significant uncertainty around key assumptions, particularly if and when SCRs would be required for continued operation, and how and when potential carbon regulation would affect Sherco 1 and 2's ability to continue to operate. Thus, while the modeling is useful to illustrate the potential costs and benefits of various scenarios and decision paths, the results must be interpreted in the context of this uncertainty. This is particularly true given the significant incremental costs associated with both retrofit and retirement scenarios.

The Company believes the most prudent option is to leave options open until there is greater certainty on the development of environmental regulations. At the same time, we recommend that clear and firm triggers be established that require reevaluation of the alternatives and provide an opportunity for a future Commission decision on the future of Sherco 1 and 2.

B. Retrofit Scenarios

As noted earlier, the only additional emission control equipment that could reasonably be anticipated to be required for Sherco 1 and 2 is the addition of Selective Catalytic Reduction (SCR) technology. If this equipment is required in the future, it will entail significant capital investments and a commensurate increase in customer rates.

However, continued operation would help maintain a diverse fuel mix on our system and mitigate exposure to fluctuations in the natural gas market.

We modeled several scenarios in Strategist that added SCRs to one or both units at Sherco. The scenarios were developed by adding estimates of the capital cost to construct the SCRs and the associated operating costs to the Reference Case. Comparison of the Strategist output for the SCR scenarios to the Reference Case provides an estimate of the incremental cost of the SCRs over the Reference Case, where Sherco continues to operate without additional emission controls.

The cost estimates for the SCRs were originally developed as part of Multi-pollutant Control Study for Sherco 1 and 2 completed by an engineering consulting firm in 2011 and then updated by the same firm in 2013 for use in this study. The costs were entered into Strategist as either capital investments or as annual operating expenses. We did not include any operational impacts from the SCRs on maximum capacity or heat rate because the cost estimates for the project include the installation of new induced draft (ID) fans, which will offset the operational impacts normally associated with SCRs.

The key SCR inputs used in Scenarios 1 and 2 include:

- SCR NO_X Reduction – 67% from baseline emissions;
- SCR Construction Cost Estimate
  - Early (2018/2019) – Unit 1: $190 million, Unit 2: $193 million
  - Late (2024/2025) – Unit 1: $218 million, Unit 2: $222 million;
- SCR Ongoing Capital Costs – Approximately $2 million/year escalating at inflation;
- SCR Variable O&M - $0.27/MWh escalating at 2.39%; and
- SCR Fixed O&M - $146,000/year escalating at 2.45%.

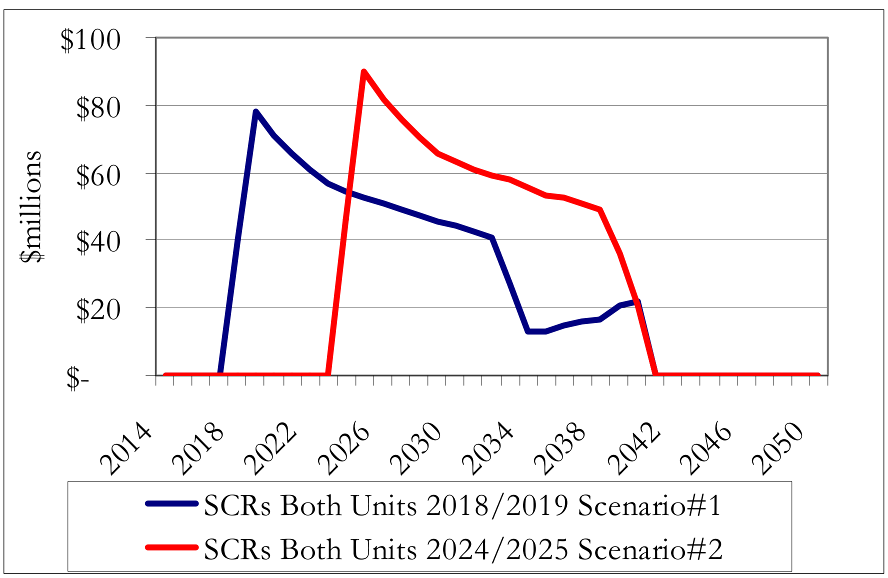
The cost impact of the SCRs are significant; if installed on both units the incremental PVRR cost is an estimated $391 million for the early installation date of 2018/2019 and $282 million for the later dates of 2024/2025. The lower cost for later installation is simply a result of discounting future costs. The costs of SCRs primarily come from the capital investments necessary to install and maintain the equipment. However, there is an additional variable O&M cost associated with chemicals necessary to remove the NO_X from the flue gas stream. The following table segregates the PVRR results for the SCR projects into four subcategories. These results are in comparison to the Reference Case, where Sherco 1 and 2 continue to operate until 2040 without the installation of any new pollution control equipment.

Table 7.1: PVRR Impacts of SCRs Relative to Reference Case

	SCRs Both Units 2018/2019 Scenario#1	SCRs Both Units 2024/2025 Scenario#2
Incremental PVRR from Reference Case	$391million	$282million
PVRR Impact By Cost Category		
Capital Revenue Reqirements	$380million	$275million
Fixed O&M and Other Annual Fixed Costs	$3million	$2million
Fuel and Other Variable Cost	$38million	$23million
Emission Costs	-$29million	-$17million
Total	$391million	$282million

In addition to PVRR impacts, it is also instructive to analyze the annual results that are produced in Strategist. This analysis will help gauge the relative rate impacts of each strategy and the timing of costs that will be borne by our customers. For the SCR alternative, the annual cost impacts begin at approximately $75 to $90 million. These costs gradually decline as the equipment is depreciated and the net book value falls.

Figure 7.2: Annual Costs Impacts for SCRs Relative to Reference Case



Most of the sensitivity tests (load, fuel prices, CO_2 costs) had little to no impact on the cost of the SCRs relative to the Reference Case, as the installation of SCRs on Sherco 1 and 2 will not significantly impact the operation of our system. For example, because Unit 1 and 2 continue to operate until 2040 in both the Reference Case and the SCR scenario, the forecasted amount of coal usage is the same in both scenarios.

As a result, when different coal prices are tested in the model, there is no change in the cost of the SCR scenario relative to the Reference Case.

The sensitivities that impact the SCR scenarios are: 1) the SCR costs assumptions, and 2) the assumed book depreciation life of the SCR equipment. As expected, the SCR +25% cost sensitivity raises the total PVRR of the scenario – that is, it increases rates. In contrast, the total PVRR is lower under the assumption of faster depreciation. Our baseline assumption for the book lives of the SCRs was 15 years. However, continued operation of the Sherco units for 15 years after the installation of the SCRs could put the Company and our customers at risk for extra costs from federal carbon legislation. To test the possibility that the cost of the SCRs could be recovered over a shorter period, allowing the plant to be retired earlier in the event of significant carbon costs, we ran sensitivities with 10 and five-year book depreciation for the SCRs. The total PVRR costs under the assumption of accelerated depreciation were lower than under the base assumption of 15 years. Although the annual book depreciation expense was higher, the shorter financing term resulted in significant savings. This is similar to a comparison of a 30-year versus a 15-year mortgage. With a longer mortgage, the monthly payments are likely to be lower, but the total interest costs will be higher. The following charts illustrate the annual impacts of the depreciation sensitivities and the total PVRR impacts of all the sensitivities ran on the SCR scenarios.

Figure 7.3: Annual Cost Impacts of SCR Book Depreciation Assumptions

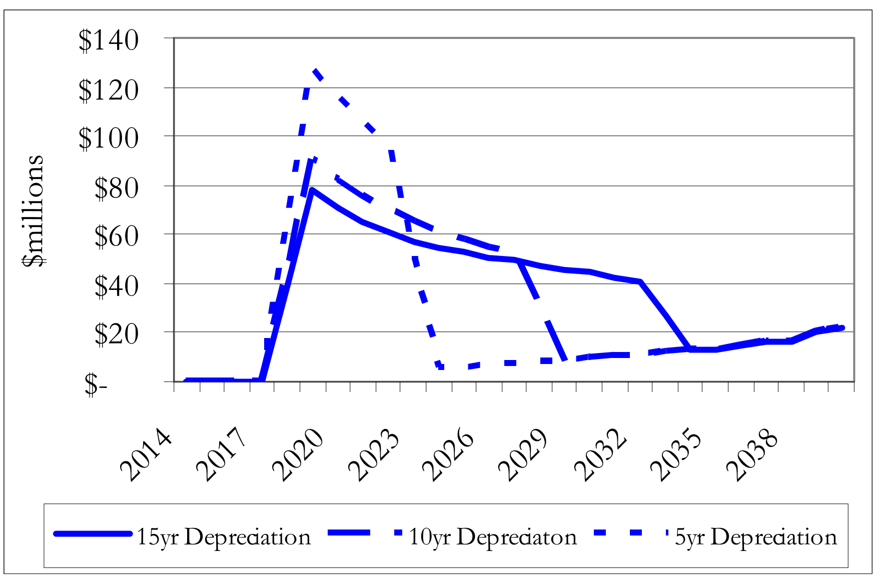
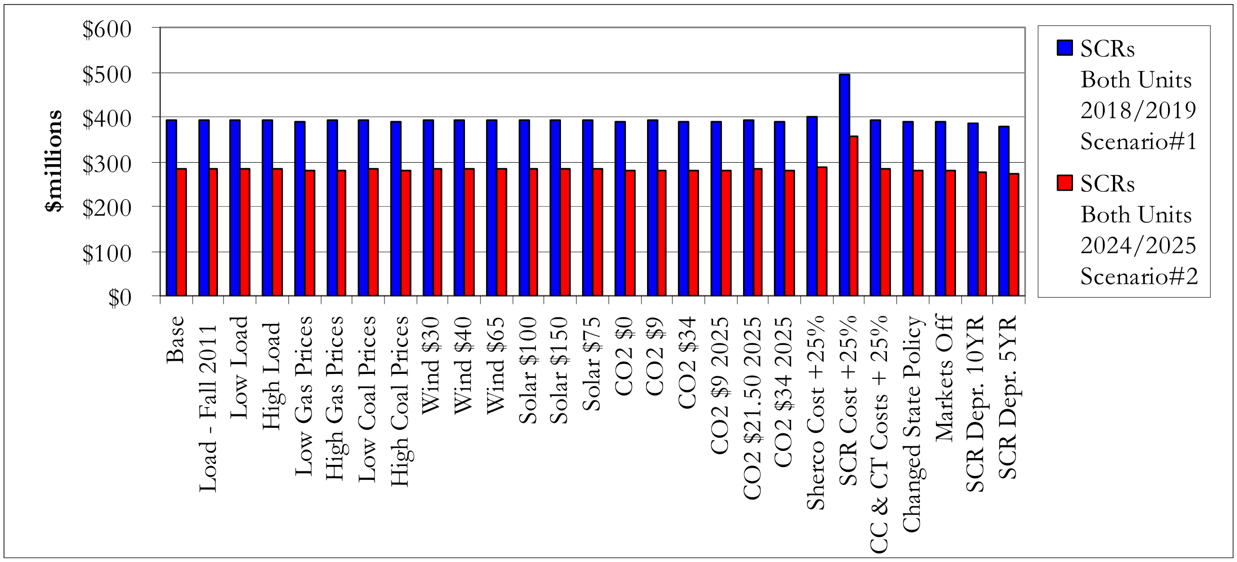


Figure 7.4: Sensitivity Analysis for SCR Scenarios



The installation of SCRs at both units at Sherco is estimated to cost almost $400 million. When depreciated over 15 years and spread across the entire five state region that the Company serves, the incremental impact on rates is 0.23¢ /kWh or less than 2%. The impact on various customer classes depend on the amount of fixed charges and proportion of baseload resource costs allocated to each class. Table 7.2 summarizes the impact of the SCRs on rates.

Table 7.2: Rate Impacts of 2018/2019 SCRs – Scenario 1

		Scenario 1 Rate Impact $ per kWh						
	Customer Class	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Scenario 1 Install SCRs Sherco 1 & 2 2018/2019	Residential	$0.0015	$0.0026	$0.0023	$0.0021	$0.0020	$0.0019	$0.0018
	C&I Non Demand	$0.0016	$0.0026	$0.0024	$0.0022	$0.0020	$0.0019	$0.0018
	C&I Demand	$0.0013	$0.0022	$0.0020	$0.0018	$0.0017	$0.0016	$0.0015
	Lighting	$0.0010	$0.0017	$0.0015	$0.0014	$0.0013	$0.0012	$0.0012
	All Classes	$0.0014	$0.0023	$0.0021	$0.0019	$0.0018	$0.0017	$0.0016

In summary, the installation of SCRs results in a cost increase for our customers, primarily due to invested capital that will flow to customers through increases in base rates. However, this is a relatively low risk strategy for complying with future environmental regulations. The primary risk is uncertainty associated with construction costs for the SCRs. Faster depreciation of the SCRs will increase near-term rate impacts, but would also provide the option of retiring the units earlier if significant federal carbon legislation is passed.

C. Retirement and Replacement Scenarios

Retirement of Units 1 and 2 is a potential alternative to adding SCRs. This strategy also results in a significant increase in customer rates, as well as increased exposure to natural gas prices, which have historically been more volatile than coal prices. However, if a tax were imposed on all CO_2 emissions at or near the $21.50/ton rate that we included in our model, the net cost of retirement and replacement would be similar to the cost of installing SCRs.

To model retirement scenarios in Strategist, the retirement date for Sherco 1 and 2 was changed from 2040 to 2019/2020 for the early retirement case or 2024/2025 for the later retirement case. The capital budget for Sherco was modified to reflect a shorter operating life with fewer investments needed to maintain the facility. The capital depreciation schedule was changed to match the modeled retirement date and the recovery of decommissioning costs was adjusted such that sufficient funds are available upon retirement to remove and remediate the site.

The resources that replace the retired Sherco units were selected in two ways. First, Strategist was allowed to select from coal, nuclear, natural gas combined cycle, natural gas peaking, wind, solar, and market energy resources in order to find the lowest cost bundle of resources that could replace Sherco 1 and 2. Using this approach, Strategist selected natural gas combined cycle units as the least cost resources to replace the retiring units. These units replaced the firm capacity needed for system reliability and provided most of the daily energy that had been produced at Sherco. Through its hourly dispatch simulation, Strategist also relied on higher operating hours at other existing units and some market purchases to make up the remaining portion of the daily energy needs. The scenarios that used Strategist to optimize the replacement resources were numbered 13 and 18.

Second, we hard-coded several different replacement alternatives in order to evaluate the cost and benefits of each alternative. By specifying particular replacement resources, we can investigate the performance of options other than the least cost alternatives selected by Strategist. The following sections provide a description of the various replacement scenarios and the input assumptions used in each.

1. Natural Gas Combined Cycle (Scenarios 14 and 19)

In these scenarios Sherco 1 and 2 are replaced with two natural gas combined cycle units. The current design of large combined cycle units achieve a maximum summer capacity of 707 MW, which is close to the per unit maximum for Sherco 1 and 2. The key natural gas combined cycle inputs used in Scenarios 14 and 19 include:

- Maximum Winter Capacity – 817 MW each;
- Maximum Summer Capacity – 707 MW each;
- Capital Costs – $692 million each;
- Natural Gas Pipeline Costs – $200 for two units;
- Ongoing Capital Costs – $3.4 million/year escalating at inflation;
- Fixed O&M – $7 million/year each escalating at 2.45%; and
- Variable O&M – $1.05/MWh each escalating at 2.39%.

Individual combined cycle plants comprised of two F class combustion turbines, two heat recovery steam generators (HRSGs), and one steam turbine (known collectively as a 2X1 CC) have been identified as near match replacements for the Sherco units. Pricing and performance information was developed based on siting the 2X1 CCs either at the Sherco site or at a new "greenfield" site. The Sherco site offers existing infrastructure for water supply and transmission interconnection, as well as land, but would need a new gas supply. As water supply is available at the current Sherco site, the 2X1 CC design and performance is based on utilization of wet cooling towers. For the greenfield options, the design, performance, and cost have been based on utilization of dry or air-cooled technology (ACC).

The 2X1 CC options are based on either General Electric (GE) 7FA Series 5 or Siemens SGT6-5000F5 combustion turbines. The two GE 7FA Version 5 or Siemens SGT6-5000F5 combustion turbines are similar to the design for a peaker. The plant has a single steam turbine generator and is designed to operate on natural gas fuel using dry, low NO_X combustion and SCR for further NO_X emissions reduction.

The natural gas fuel supply required for either the 2X1 CC plants or the combustion turbine peaker plants is anticipated to be from existing interstate pipelines in the NSP service territory. We have discussed availability and potential for service with several suppliers, including Northern Natural Gas, Alliance Pipeline, WBI, and Viking. Based on these discussions, we assumed supply from the Alliance pipeline, as it appears to have the capacity to serve the large new loads and have the potential for firm service. In order to provide service to the vicinity of Sherco, a new 88-mile line from Alliance would be required. The preliminary cost estimate is approximately $200 million. This cost has been included in the capital estimates for the 2X1 CCs located at Sherco.

2. Natural Gas Peaking Units + Wind Resources (Scenarios 15 and 20)

These scenarios replaced the firm capacity from Sherco 1 and 2 needed for reliability with natural gas peaking units with the majority of the energy normally generated by Sherco replaced with additional wind generation. Specifically, the replacement bundle consisted of 3,000 MW of wind and five peaking units with a summer rating of 192 MW each. The amount of wind was selected such that approximately 100% of the energy produced by Sherco is replaced by renewable energy. This represents an large increase in the amount of wind energy on the NSP System. Currently, we have approximately 1,800 MW installed, which is equivalent to about 14% of our total energy mix, and to comply with the Minnesota Renewable Energy Standard we must achieve a wind penetration level of 25% of retail sales by 2020. The additional 3,000 MW to replace the energy from Sherco with wind would bring the total wind penetration on our system to 44%. To accommodate this additional wind generation, the model included $700 million for new transmission infrastructure to deliver the power from high wind areas to our load centers. The baseline assumption for wind pricing is based on our current estimate of the cost of wind turbines without the benefit of the federal production tax credit, which is set to expire at the end of 2013. The key natural gas combustion turbine inputs used in Scenarios 15 and 20 include:

- Maximum Winter Capacity – 226 MW;
- Maximum Summer Capacity – 192 MW;
- Capital Costs – $136 million each escalating at inflation;
- Fuel Supply and/or Transmission Costs – $40 million each escalating at inflation;
- Ongoing Capital Costs – $1.3 million/year each escalating at inflation;
- Fixed O&M – $668,000/year each escalating at 2.45%; and
- Variable O&M – $1.40/MWh escalating at 2.39%.

The key wind generation inputs include:

- Purchase Costs – $44/MWh (2014) escalating at inflation ($53/MWh levelized);
- Wind Integration Costs – $1.13 escalating with the price of natural gas; and
- Transmission – $700 million capital investment to support 3,000 MW of wind escalating at inflation.

The combustion turbine facility is estimated on the basis of a greenfield plant located near a major interstate gas pipeline and a 345 kV transmission line to minimize the cost impacts of interconnection costs. On that basis, it has been assumed for this study that the plants would be adjacent to the Alliance pipeline, with one plant located near Franklin, Minnesota and one near Fargo, North Dakota. The simple cycle or peaker plants assumed for this study are comprised of three F class combustion turbines.

3. *Natural Gas Peaking Units + Wind Resources +Solar (Scenarios 16 and 21)*

We modified the preceding scenario to include solar electricity as part of the replacement bundle for Sherco. Specifically, this scenario has three natural gas peaking units, 2,200 MW of wind, and 1,200 MW of solar. The amount of transmission investment necessary to support the delivery of wind power was decreased proportionally to the lower level of wind and no additional transmission was added for the solar, as it is expected that the solar resources can be constructed at or near load centers. Under this scenario wind penetration reaches 38% and solar reaches 5%. The key inputs include:

- Natural Gas Combustion Turbine – Same as scenarios 15 and 20
- Wind – Same as scenarios 15 and 20
  - Transmission – $550 million capital investment to support 2,200MW of wind escalating at inflation
- Solar
  - Purchase Costs – $105/MWh (2014) escalating at inflation ($125/MWh levelized)
  - No Solar Integration Costs
  - No Additional Costs for Transmission Infrastructure.

4. *Natural Gas Peaking Units + Wind Resources +Solar + DSM (Scenarios 17 and 22)*

Our final hard-coded replacement bundle added DSM to the wind and solar replacement energy. The Company has conducted extensive energy conservation programs in our service territory, which suggests the opportunities for additional savings are diminishing. Our Reference Case assumptions include the 1.5% DSM goal for 2014-2016 and 1.4% for the remaining years. This enhanced DSM scenario raises the DSM achievements to 1.6%, which is an increase equivalent to 55 MW and 295 GWh annually. Specifically, these scenarios include three natural gas peaking units, 2,000 MW of wind, 1,100 MW of solar, and DSM equal to 1.6% of sales. The key inputs include:

- Natural Gas Combustion Turbine – Same as scenarios 16 and 21;
- Wind – Same as scenarios 16 and 21
  - Transmission – $500 million capital investment to support 2,000 MW of wind escalating at inflation;
- Solar – Same as scenarios 16 and 21; and
- DSM – $264 million spent over five years to achieve an incremental 55 MW and 295 GWh.

5. *Summary*

Under the base assumptions used in Strategist, including \$21.50/ton CO_2 costs, the PVRR impact of retirement and replacement with natural gas combined cycle units is similar to the PVRR impact of the installation of SCRs. Note that the optimized replacement scenario also selected the combined cycle alternatives, giving it an identical PVRR impact.

Table 7.3: PVRR Impacts of Retirement Scenario Relative to Reference Case

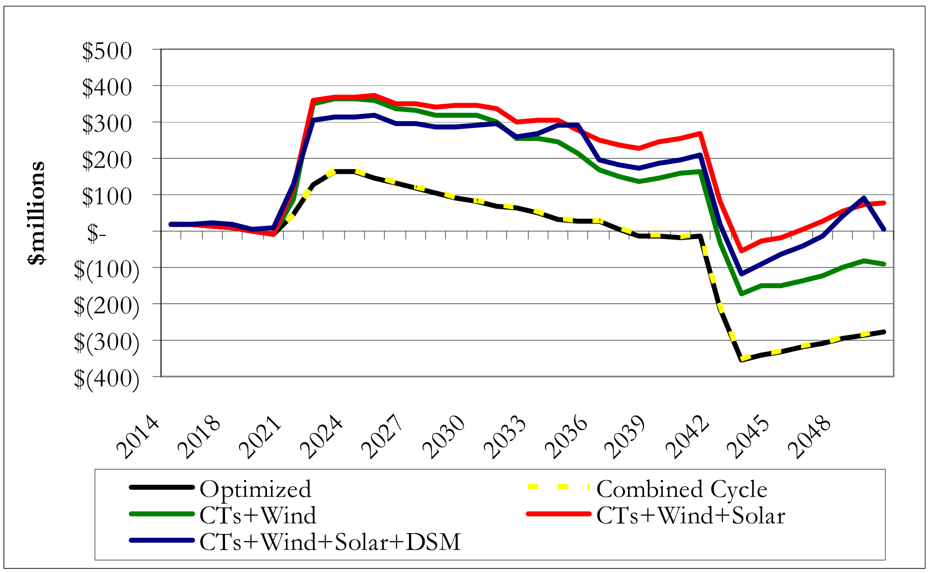
	Retire Both Units 2019/2020 Optimized Replacement Scenario#13	Retire Both Units 2019/2020 CC Replacement Scenario#14	Retire Both Units 2019/2020 CT + Wind Replacement Scenario#15	Retire Both Units 2019/2020 CT + Wind + Solar Replacement Scenario#16	Retire Both Units 2019/2020 CT + Wind + Solar + DSM Replacement Scenario#17
Incremental PVRR from Reference Case	\$354 million	\$354 million	\$1,789 million	\$2,154 million	\$1,849 million
PVRR Impact By Cost Category					
Capital Revenue Reqirements	\$789 million	\$789 million	\$728 million	\$229 million	\$175 million
Fixed O&M and Other Annual Fixed Costs	(\$295million)	(\$295million)	(\$375million)	(\$400million)	(\$398million)
Fuel and Other Variable Cost	\$1,087 million	\$1,087 million	\$3,051 million	\$4,020 million	\$3,609 million
Wind Integration Costs	\$0 million	\$0 million	\$430 million	\$317 million	\$287 million
DSM Expenses	\$0 million	\$0 million	\$0 million	\$0 million	\$146 million
Emission Costs	(\$1,228million)	(\$1,228million)	(\$2,044million)	(\$2,011million)	(\$1,970million)
Total	\$354 million	\$354 million	\$1,789 million	\$2,154 million	\$1,849 million

Table 7.3 illustrates the large impact the CO_2 assumption has on the PVRR results. For the combined cycle scenario, there is a \$1.2 billion CO_2 benefit associated with retirement of Sherco. That benefit more than offsets the \$1.1 billion cost increase from higher levels of natural gas generation.

The addition of wind and solar to the replacement scenarios adds significant costs to the replacement of Units 1 and 2. At \$53/MWh levelized plus transmission costs, the wind resources are not cost-effective alternatives. This reflects the role of the federal production tax credit (PTC) in the economics of wind. Later in this section we show the results of a sensitivity test where the price of wind is lowered to a level that reflects the benefit of the PTC; under those assumptions, wind is much more cost-effective. The addition of solar resources at a price of \$125/MWh levelized is also not cost-effective, even though the solar additions eliminated the need for two natural gas combustion turbines. The addition of DSM does create a net decrease in PVRR. The PVRR results, however, do not reflect some incremental cost that will be paid by participants in those programs, suggesting the total societal cost of the DSM programs is higher. Also, because DSM simultaneously reduces costs and sales, the net impact on rates may be positive or negative. The result of a later retirement and replacement of Sherco in the 2024/2025 timeframe had very similar PVRR results, but the total PVRR values were lower due to discounting the costs over more years.

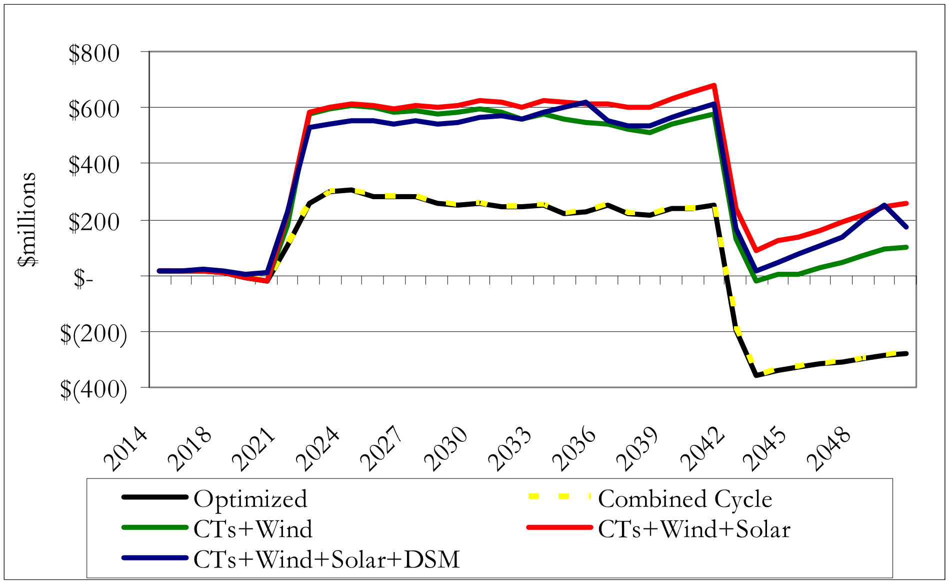
The annual cost impacts for the retirement scenarios show significant cost increases at the time of retirement that gradually decline over time. When considering a CO_2 cost of $21.50/ton, replacement with natural gas combined cycle units has a first year impact of $160 million. After 2040 the retirement scenarios shows significant cost savings. This is because in the Reference Case Sherco 1 and 2 retire in 2040 and must be replaced by new generation. But in the retirement scenarios, this replacement capacity was constructed earlier at lower cost and then significantly depreciated by 2040, thus lowering its cost even further.

Figure 7.5: Annual Costs for Retirement Relative to Reference Case – CO_2 $21.50/ton



As noted previously, under the base assumptions there is a large benefit from the reduction of CO_2 emissions associated with retirement of Sherco 1 and 2. Figure 7.6 also shows the annual cost impacts from the retirement scenarios but under the assumption of $0/ton CO_2 (sensitivity N). Without the cost on carbon, the first-year cost impact of replacing Sherco with natural gas combined cycles is $320 million.

Figure 7.6: Annual Costs for SCRs Relative to Reference Case – CO_2 $0/ton



Retirement of Sherco 1 and 2 would fundamentally change the NSP System with respect to energy mix and annual emissions. As a result, the sensitivity tests that involve fuel and emissions costs show variability associated with the retirement scenarios. Also, the sensitivities associated with the cost of wind that, with the assumption of $21.50/ton CO_2, wind is cost-effective at the $30/MWh levelized price (including the cost for transmission infrastructure). A review of all the input assumption sensitivities run in Strategist is provided in Appendix B. The following graph and table show the relative costs of the replacement alternatives under a range of sensitivities. In the table, negative values indicate that retirement is lower cost than the Reference Case.

Figure 7.7: Sensitivity Analysis for Retirement Scenarios

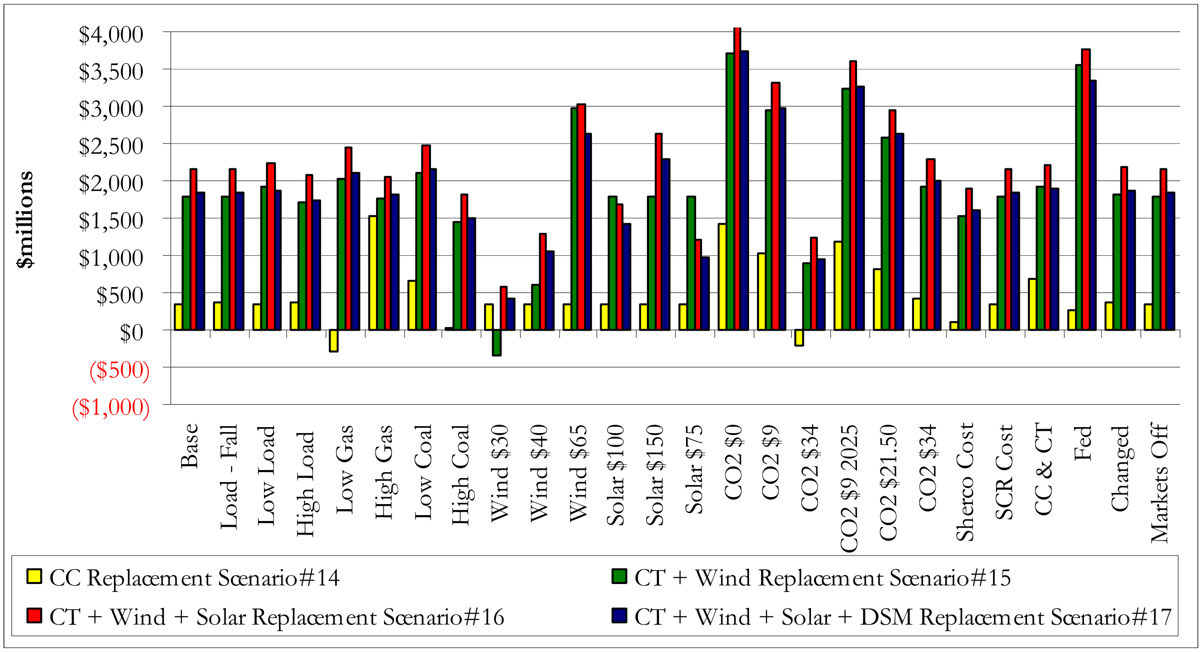


Table 7.4: Sensitivity Analysis for Retirement Scenarios

PVRR Impacts Relative to the Reference Case $millions	Optimized Replacement Scenario #13	CC Replacement Scenario #14	CT + Wind Replacement Scenario #15	CT + Wind + Solar Replacement Scenario #16	CT + Wind + Solar + DSM Replacement Scenario #17
Base	$354	$354	$1,789	$2,154	$1,849
Load - Fall 2011	$363	$363	$1,789	$2,156	$1,851
Low Load	$339	$339	$1,916	$2,250	$1,876
High Load	$363	$363	$1,703	$2,090	$1,724
Low Gas Prices	($278)	($278)	$2,032	$2,444	$2,100
High Gas Prices	$1,524	$1,524	$1,768	$2,056	$1,804
Low Coal Prices	$648	$648	$2,115	$2,469	$2,161
High Coal Prices	$29	$29	$1,437	$1,811	$1,509
Wind $30	$354	$354	($343)	$581	$424
Wind $40	$354	$354	$602	$1,278	$1,055
Wind $65	$354	$354	$2,963	$3,020	$2,633
Solar $100	$354	$354	$1,789	$1,676	$1,412
Solar $150	$354	$354	$1,789	$2,632	$2,285
Solar $75	$354	$354	$1,789	$1,198	$976
CO2 $0	$1,425	$1,425	$3,723	$4,082	$3,732
CO2 $9	$1,017	$1,017	$2,942	$3,304	$2,973
CO2 $34	($211)	($211)	$884	$1,236	$951
CO2 $9 2025	$1,175	$1,175	$3,239	$3,602	$3,264
CO2 $21.50 2025	$806	$806	$2,572	$2,941	$2,620
CO2 $34 2025	$417	$417	$1,925	$2,293	$1,988
Sherco Cost +25%	$101	$101	$1,536	$1,901	$1,596
SCR Cost +25%	$354	$354	$1,789	$2,154	$1,849
CC & CT Costs + 25%	$672	$672	$1,911	$2,198	$1,893
Fed Externalities	$273	$273	$3,561	$3,774	$3,346
Changed State Policy	$358	$358	$1,818	$2,172	$1,867
Markets Off	$354	$354	$1,789	$2,154	$1,849
SCR Depr. 10YR	$354	$354	$1,789	$2,154	$1,849
SCR Depr. 5YR	$0	$0	$0	$0	$0

We evaluated the rate impacts of the retirement scenarios under the assumption of \$0/ton CO_2. At this time, there is no firm proposal to implement a direct tax on CO_2 that would be similar to the \$21.50/ton planning value that is used in the Strategist base assumptions. The following table shows that the natural gas combined cycle replacement option is expected to increase rates by over 1¢/kWh by 2024. This would be an approximate 8% increase in rates, both a base rate increase due to plant investment and increased fuel charges.

Table 7.5: Rate Impacts of Retirement Scenarios

	Customer Class	Scenario 13 Rate Impact $ per kWh 2018	2019	2020	2021	2022	2023	2024
Scenario 13 Replace Sherco 1 & 2 with Natural Gas Combined Cycle	Residential	$0.0025	$0.0070	$0.0103	$0.0113	$0.0116	$0.0115	$0.0105
	C&I Non Demand	$0.0025	$0.0071	$0.0103	$0.0113	$0.0116	$0.0115	$0.0105
	C&I Demand	$0.0021	$0.0058	$0.0082	$0.0088	$0.0090	$0.0091	$0.0083
	Lighting	$0.0016	$0.0042	$0.0057	$0.0058	$0.0059	$0.0060	$0.0054
	All Classes	$0.0022	$0.0061	$0.0089	$0.0096	$0.0098	$0.0098	$0.0089

Overall, the cost-effectiveness of the retirement scenarios is heavily dependent upon the CO_2 pricing assumption used and the price of the replacement technology. The natural gas replacement scenario appears to be cost-effective under the assumption of $21.50/ton CO_2 and lower-than-forecasted natural gas prices. Similarly, the renewable energy replacement alternatives might be cost-effective with CO_2 pricing and low cost for wind and solar. Under the assumption of $0/ton CO_2 costs and current pricing of natural gas and renewables, retirement is expected to be much higher cost than the SCR scenarios.

D. Combined Scenarios

We also evaluated scenarios where an SCR was installed at one unit with the other unit retired and replaced with the various alternatives discussed in the previous section. As is to be expected, the Strategist results for the combined scenarios are approximately halfway between the full SCR and the full retirement scenarios. For the combination scenarios Unit 1 was retired and Unit 2 was retrofitted with an SCR, but Unit 1 and Unit 2 could have been interchanged without significantly impacting the results. The cost and performance assumptions used were the same as listed in the preceding sections.

The PVRR results for the combination scenario indicate that if Unit 1 is replaced by a combined cycle unit, the incremental costs are similar to the full retirement or the full SCR scenarios under base assumptions. However, if the other more costly replacement alternatives are utilized, the incremental cost estimates fall somewhere between the full SCR and the full retirement strategies.

Table 7.6: PVRR Impacts of Combination Scenarios Relative to Reference Case

	Retire Unit 1 2019 Optimized Replacement Unit 2 SCR 2019 Scenario#3	Retire Unit 1 2019 CC Replacement Unit 2 SCR 2019 Scenario#4	Retire Unit 1 2019 CT+Wind Replacement Unit 2 SCR 2019 Scenario#5	Retire Unit 1 2019 CT+Wind +Solar Replacement Unit 2 SCR 2019 Scenario#6	Retire Unit 1 2019 CT+Wind +Solar+DSM Replacement Unit 2 SCR 2019 Scenario#7
Incremental PVRR from Reference Case	$467 million	$467 million	$897 million	$1,231 million	$959 million
PVRR Impact By Cost Category					
Capital Revenue Reqirements	$682 million	$682 million	$582 million	$313 million	$259 million
Fixed O&M and Other Annual Fixed Costs	($150million)	($150million)	($200million)	($219million)	($217million)
Fuel and Other Variable Cost	$573 million	$573 million	$1,334 million	$2,036 million	$1,651 million
Wind Integration Costs	$0 million	$0 million	$178 million	$157 million	$127 million
DSM Expenses	$0 million	$0 million	$0 million	$0 million	$146 million
Emission Costs	($637million)	($637million)	($998million)	($1,055million)	($1,008million)
Total	$467 million	$467 million	$897 million	$1,231 million	$959 million

The annual cost impacts show that the combination scenario could mitigate the cost impacts to customers in comparison to the full retirement case. However, the annual cost impacts still reach almost $400 million when no cost is assigned to CO_2.

Figure 7.8: Annual Costs for Combination Scenario Relative to Reference Case CO2 $21.50/ton

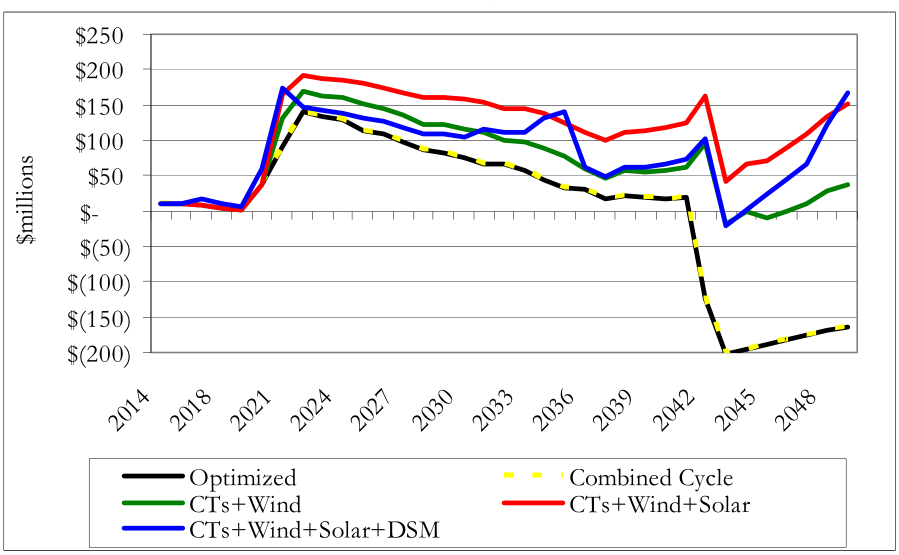
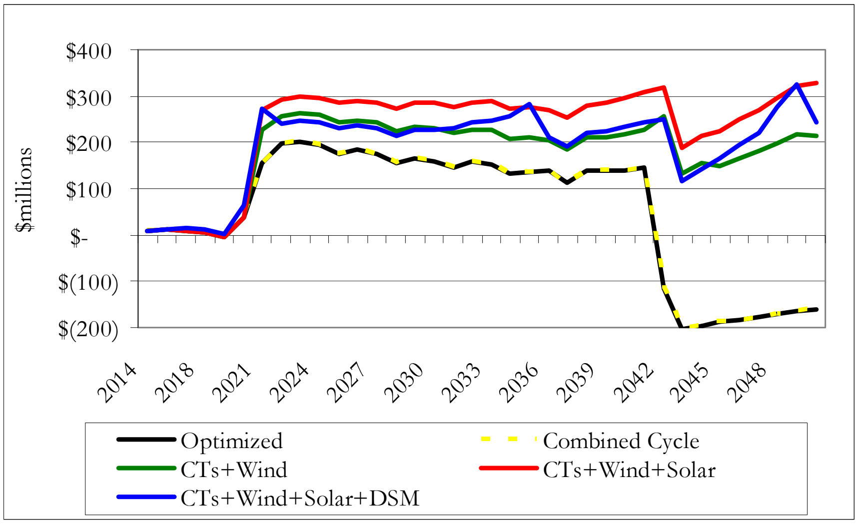


Figure 7.9: Annual Costs for Combination Scenario Relative to Reference Case CO2 $0/ton



The sensitivity analysis performed on the combination scenario shows that by diversifying the strategies used in Sherco 1 and 2's life cycle management, we could potentially limit our exposure to any one risk factor. For example, in comparison to the full retirement scenario, the impact of the high gas scenario is mitigated by the combination scenario. Conversely, the impact of the high coal price scenario is higher.

Figure 7-10: Sensitivity Analysis for Combination Scenario

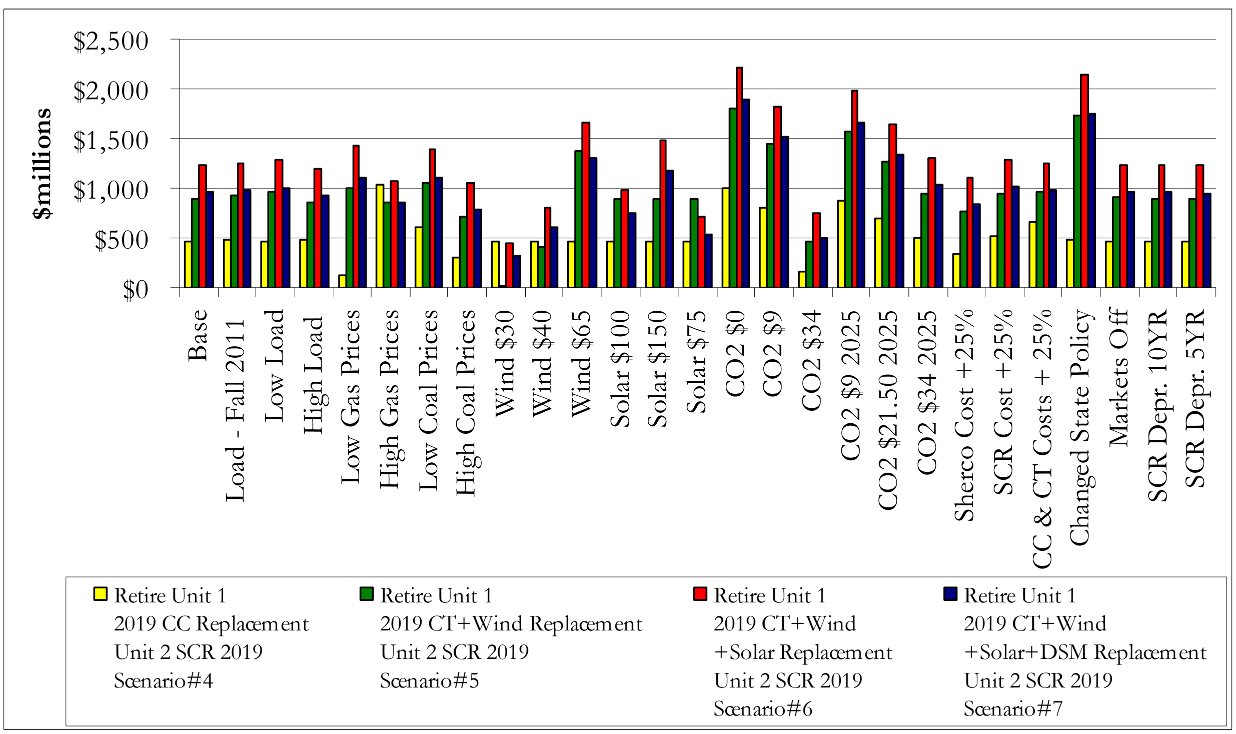


Table 7.7: Sensitivity Analysis for Combination Scenarios

PVRR Impacts Relative to the Reference Case $millions	Retire Unit 1 2019 Optimized Replacement Unit 2 SCR 2019 Scenario#3	Retire Unit 1 2019 CC Replacement Unit 2 SCR 2019 Scenario#4	Retire Unit 1 2019 CT+Wind Replacement Unit 2 SCR 2019 Scenario#5	Retire Unit 1 2019 CT+Wind +Solar Replacement Unit 2 SCR 2019 Scenario#6	Retire Unit 1 2019 CT+Wind +Solar+DSM Replacement Unit 2 SCR 2019 Scenario#7
Base	$467	$467	$897	$1,231	$959
Load - Fall 2011	$475	$475	$921	$1,248	$978
Low Load	$456	$456	$958	$1,283	$1,002
High Load	$474	$474	$849	$1,194	$926
Low Gas Prices	$124	$124	$1,000	$1,424	$1,099
High Gas Prices	$1,034	$1,034	$858	$1,068	$862
Low Coal Prices	$610	$610	$1,052	$1,386	$1,110
High Coal Prices	$296	$296	$721	$1,054	$784
Wind $30	$467	$467	$14	$453	$329
Wind $40	$467	$467	$405	$798	$608
Wind $65	$467	$467	$1,384	$1,660	$1,306
Solar $100	$467	$467	$897	$974	$743
Solar $150	$467	$467	$897	$1,489	$1,175
Solar $75	$467	$467	$897	$717	$527
CO2 $0	$999	$999	$1,804	$2,220	$1,891
CO2 $9	$797	$797	$1,441	$1,822	$1,517
CO2 $34	$154	$154	$459	$745	$497
CO2 $9 2025	$878	$878	$1,578	$1,976	$1,663
CO2 $21.50 2025	$700	$700	$1,267	$1,640	$1,347
CO2 $34 2025	$503	$503	$955	$1,303	$1,029
Sherco Cost +25%	$342	$342	$771	$1,105	$833
SCR Cost +25%	$518	$518	$947	$1,282	$1,009
CC & CT Costs + 25%	$652	$652	$969	$1,251	$978
Changed State Policy	$306	$480	$1,729	$2,140	$1,748
Markets Off	$468	$468	$907	$1,235	$965
SCR Depr. 10YR	$464	$464	$894	$1,228	$956
SCR Depr. 5YR	$461	$461	$890	$1,225	$952

E. Scenario to meet 80% CO_2 Reduction by 2050

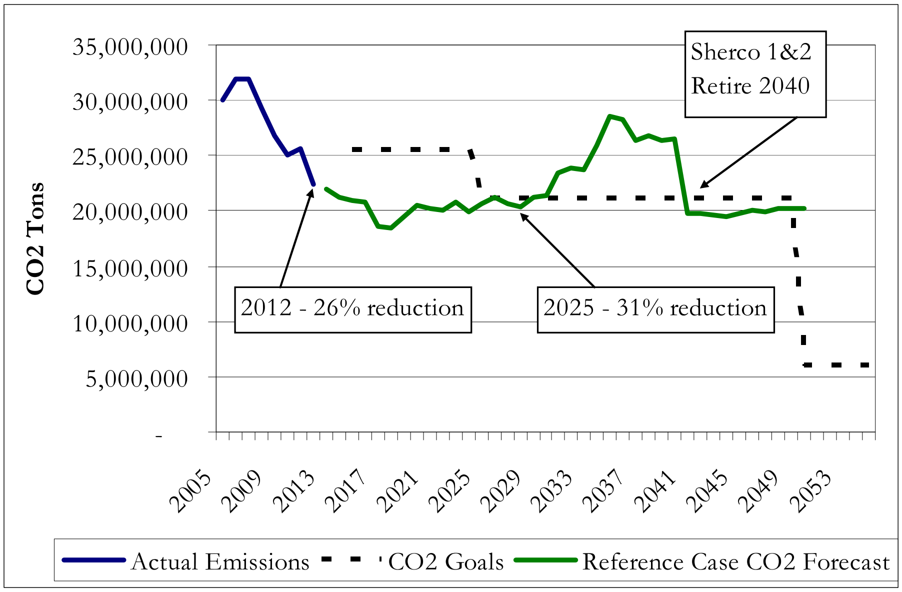
The Commission's November 30, 2013 Order in our 2011-2025 Resource Plan specified that our life cycle management study should include analysis of least cost scenarios that reduce greenhouse gas emissions by 80% by 2050, relative to 2005 levels. While we provide information on this scenario below, the strategy for life cycle management of Sherco does not impact our ability to achieve the 80% goal. In this study the latest retirement date for Sherco 1 and 2 is 2040. Thus, under all scenarios presented, the units will retired by 2050 and will not impact the achievement of the 80% goal.

Through conservation, renewable energy additions, and MERP, we have already reduced our CO_2 emissions by over 25% from 2005 levels. That puts us well ahead of the 2015 goal of a 15% reduction. Our Reference Case Strategist model, which includes continued operation of Sherco 1 and 2, forecasts that we will also meet the 2025 goal of a 30% reduction. In the 2030 to 2035 timeframe, the CO_2 emissions for the NSP system may increase significantly with the retirement of our Monticello and Prairie Island nuclear plants. These CO_2-free resources account for approximately 29% of our total system generation and replacement options will need to be carefully considered before their retirement dates arrive.

By 2050 all of NSP's current coal fleet will likely be retired. What resources comprise our energy portfolio and affect our ability to meet the 80% reduction goal will depend on how generation technologies evolve over the next several decades. Depending on cost, nuclear generation may contribute to achieving significant CO_2 reductions. Alternatively, renewable resources would likely supply a majority of energy on our system. While cost estimates over this timeframe are speculative, we have run various Strategist analyses around the 80% reduction scenario. One Strategist analysis indicated that approximately 13,000 MW of wind and 4,500 MW of solar energy would be needed to meet the 80% goal. Such a large proportion of intermittent resource would require significant energy storage capability. To meet the CO_2 goal Strategist also selected 5,000 MW worth of battery storage technology.

Regardless of the specific technologies chosen, achievement of an 80% CO_2 reduction will be challenging, requiring that approximately 85% of our energy come from renewable resources or other CO_2-free generation by 2050. However, given the long time horizon for this emissions reduction goal, Sherco 1 and 2 do not play a significant roll in reaching the target.

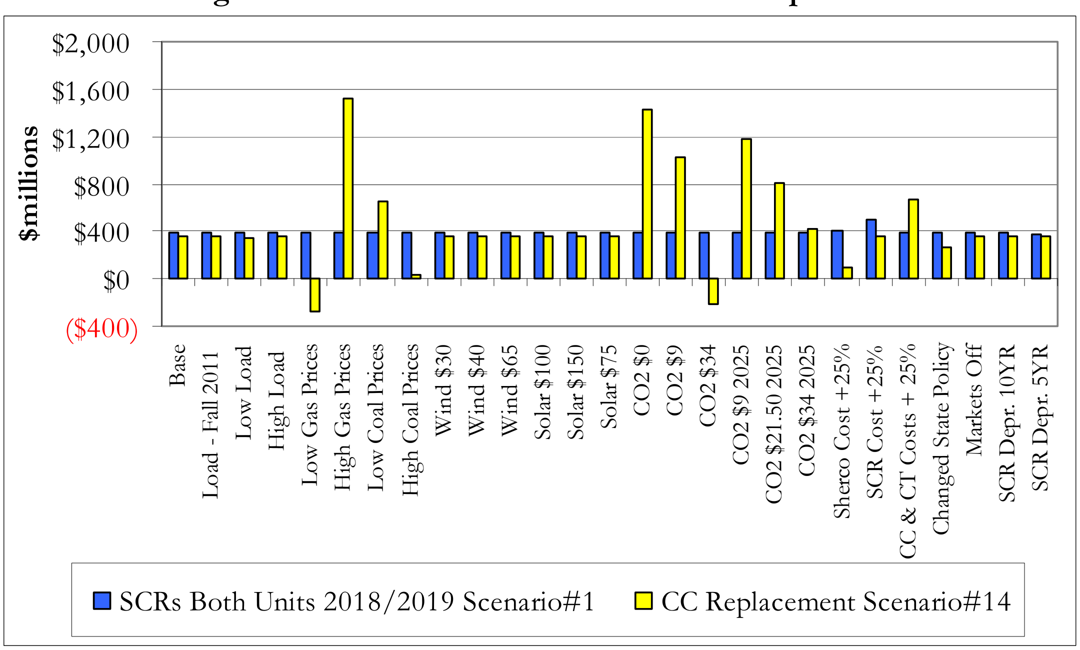
Figure 7.11: NSP Historic CO2 Emissions, CO_2 Goals, and Reference Case Projections



F. Summary

The Strategist analysis suggests that the installation of SCR equipment to comply with potential environmental regulations is costly, but that the alternative strategy of retirement is likely to have a much higher impact on customer rates and would only be cost-effective with a significant cost on CO_2 emissions. Figure 7.12 shows the difference in cost between SCR and retirement scenarios for a range of assumptions, including CO_2 costs and natural gas prices.

Figure 7.12: SCR vs. Retirement PVRR Comparison



We believe that a strategy that aligns the timing of a decision on the future of Sherco 1 and 2 with the availability of additional information on the necessity for SCRs and impending cost on CO_2 is in the best interest of our customers. If federal or state regulations are adopted that require lower NO_X emissions at Sherco 1 and 2, then the Company will reevaluate whether the installation of SCRs or retirement is the preferred strategy. The analysis shows that faster depreciation of the SCRs increases near-term rate impacts, but provides the option of retiring the units earlier than 2040 if significant federal carbon legislation is adopted.

Chapter 8. Other Considerations

The analysis identifies least cost options under a range of sensitivities to help inform what decision alternatives result in the lowest cost for all customers. It is also appropriate, however, to recognize that there are impacts of retirement that the Strategist analysis does not capture.

A. Socioeconomic Impacts

The Sherco Plant is the primary economic driver of the city of Becker, which is a small community with a population of approximately 4,600 people. Sherco provides jobs for local residents, contributes to local tax revenue, and supports local schools and police and fire services. Sherco's operations also support regional jobs, including railroad and mining jobs. The steam from Sherco 1 and 2 is sold to Liberty Paper, also a major employer in Becker, for its operations. Thus, the decisions made on the future of Sherco 1 and 2 will directly and significantly impact Becker, Liberty Paper, and surrounding communities. The following analysis evaluates the potential impacts the loss of jobs and decline in tax revenue would have on the city of Becker, as well as the impacts of Sherco 1 and 2 retirement on Liberty Paper.

1. Jobs

The Sherco Plant employs a total of approximately 370 people, of which 300 are full-time employees and 70 are contractors. Of the total full-time employees, approximately 150 directly support Units 1 and 2. An additional 40 people are employed in management or support roles serving all three units. More than half of Sherco's employees live in Becker and the surrounding communities. Should Units 1 and 2 be shut down, it is possible that the majority and possibly all employees at Units 1 and 2 would be laid off. In the event that a natural-gas-fired plant is built on the former Sherco 1 and 2 site, some employees may be able to remain, but not all, as natural gas plants have lower staffing requirements. The loss of jobs at Sherco could have cascading effects throughout the local economy, as fewer dollars are spent at local restaurants, grocery stores, hotels, and other businesses.

In addition to local jobs, the Sherco Plant supports regional jobs in the mining and railroad industries. Sherco receives an average of three rail deliveries of coal per day. The coal is delivered from mines in Wyoming and Montana. The retirement of Sherco 1 and 2 would reduce the demand for coal, which would reduce the number of rail deliveries and amount of coal needed from the mine. This reduction could result in layoffs at the railroad and mining companies.

2. *Tax Base*

In 2013, property taxes related to the Sherco plant will total approximately $6.4 million, with $4.15 million paid to Sherburne County and $2.25 million paid to the city of Becker. The tax revenues from Sherco comprise approximately 75% of the city of Becker's budget, making it the primary source of revenue for the city. Absent this tax revenue, the city would have to significantly increase the tax rate, which would likely shift the tax base from industrial taxpayers to residential and commercial taxpayers. This increase in taxes could force local residents and businesses out of Becker, further reducing tax revenue. This is in addition to the expected departure of Sherco employees who must leave Becker in search of different employment. As more and more residents leave Becker the property values will likely decline and the tax base will be further reduced, thus creating a vicious circle that challenges the city's viability. Additionally, because schools are paid based on enrollment, a decline in enrollment would also reduce funding to local schools.

3. *Liberty Paper*

Retirement of Units 1 and 2 would also impact Liberty Paper. Liberty Paper is a private company that operates a paper mill adjacent to the Sherco facility and employs approximately 135 people. Built in 1994, the mill was sited there specifically for the steam supply from Units 1 and 2. If Units 1 and 2 are retired, Liberty Paper must produce an alternative source of steam or cease operations. While the option may exist to install a boiler in the mill, the cost would be significant and beyond what Liberty Paper anticipated when agreeing to locate in Becker. The company estimates that they would need three years advance notice to design, permit and install a boiler. If Liberty Paper is forced to close or relocate due to the economics of replacing the steam from Sherco 1 and 2, the impacts to the Becker community will be compounded.

B. System Reliability

The Commission's Order in our last Resource Plan required the life cycle management study to include an analysis of how a temporary or permanent outage at either Sherco 1 or 2 would affect system reliability. The Company hired a consultant to analyze the impact of a temporary or permanent outage at both Sherco 1 and 2, as well as determine if any new system reliability concerns arise from the new generation pattern. The consultant performed stability analysis using a 2022 shoulder season (off-peak) stability model that was developed using the MISO generator interconnection study model used for the August 2012 generator interconnection studies. The stability study evaluated both voltage and rotor angle conditions following the occurrence of both regional and local transmission disturbances. The stability analysis was performed for the following conditions, which were considered the most limiting:

- Sherco 1 and 2 out of service;
- Sherco 1, 2 and 3 out of service; and
- Sherco 1 and 2 and Monticello out of service.

The analysis did not identify any areas of concern regarding dynamic or voltage stability. All conditions were within the reliability requirements. The analysis did show a slightly worse voltage response for regional disturbances with the generating units out of service, but all were within the allowable limits.

The transmission studies performed only evaluated a few specific conditions on the transmission system. A more thorough analysis would necessitate studying additional conditions and would include stressing the transmission system for a larger range of conditions in which one would expect to see when operating the transmission system. This additional analysis would include studies at various power transfer levels across the transmission system, various load levels, and various generation dispatches. A more thorough analysis could identify additional issues that would need to be addressed.

It is also important to note that replacement generation would need to be in place prior to retirement of one or both units. This ensures adequate supply in the absence of Sherco 1 and 2, which would mitigate reliability issues.

Chapter 9. Conclusion

The Company completed an extensive analysis of the costs of continuing to operate Sherco 1 and 2, including retrofitting the units with SCRs to further reduce NO_X emissions. Those results were compared to a broad range of replacement alternatives using both a longer-term planning perspective traditionally used in resource planning as well as a shorter-term rate impact view. The Company also reviewed the emerging and potential future air quality regulations and assessed the current status of federal carbon regulation. The analysis shows that Sherco 1 and 2 can continue to provide cost-effective electricity to our customers well into the future. However, the relative cost-effectiveness of the retirement and retrofit scenarios depends on assumptions about the price and timing of carbon regulation and natural gas prices. Lower or no carbon costs and higher natural gas prices favor a retrofit decision, while higher carbon costs and lower natural gas prices favor retirement. Under the Reference Case assumptions, including a CO_2 cost of $21.50/ton, the cost difference between installing SCRs and retiring the units is negligible.

The Company believes the most prudent option is to continue to operate Sherco 1 and 2. Doing so leaves both continuing operation and replacement options open until there is greater clarity and certainty on the development of environmental regulations and the associated timing and cost. We have identified two key public policy decisions, either of which should trigger a reassessment. If and when air quality regulations require the addition of selective catalytic reduction, we intend to reexamine the alternatives before making the nearly $400 million investment in the plant. If and when policies are established that create significant costs associated with CO_2 emissions a reassessment is warranted as well. To help guide subsequent Resource Plan proceedings, we recommend these triggers be established that require reevaluation of the alternatives and provide an opportunity for a future Commission decision on the future of Sherco 1 and 2. Specifically, we recommend the Commission require reanalysis when: 1) air quality regulations establish a need for SCRs, or 2) a carbon regulation framework takes shape. This strategy aligns the timing of a decision on the future of Sherco 1 and 2 with the availability of more complete information, which reduces the risk of imposing significant and potentially unnecessary costs onto customers.

Appendix A
Assessment of Federal and State Environmental Regulations and Impacts on Sherco Units 1 and 2

I. AIR QUALITY REGULATION OF EMISSIONS OF CRITERIA AND HAZARDOUS AIR POLLUTANTS

The EPA and the Minnesota Pollution Control Agency (MPCA) have promulgated air quality regulations that reduce emissions of air pollutants in order to protect the health and welfare of the general public. These regulations reduce emissions from a wide variety of sources of air pollution, including coal-fired power plants. The following sections describe the major air quality rules and regulations that impact Sherco Units 1 and 2.

A. National Ambient Air Quality Standards

The Clean Air Act (CAA) requires EPA to set National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health and the environment. There are two types of NAAQS: (1) primary standards that set limits to protect public health, including the health of sensitive populations, such as asthmatics, children, and the elderly; and (2) secondary standards that set limits to protect public welfare, including protection against damage to animals, crops, and buildings.[1] EPA has established NAAQS for: particulate matter, ozone, nitrogen oxides, sulfur dioxide, carbon monoxide, and lead. EPA is required to review the standards every five years and revise them as appropriate to protect public health and welfare. Pollutants regulated under a NAAQS are called "criteria" air pollutants.[2] The NAAQS program has been in place since the early 1970s.

Once EPA adopts or revises a NAAQS, states are required to monitor their air quality to determine whether the ambient air in any areas of the state fail to meet the NAAQS. This process identifies areas that will be designated as in attainment of the NAAQS or in nonattainment of the NAAQS. Typically, this process is completed two years after a NAAQS revision. States analyze their air monitoring data and submit to EPA their designations of parts of the state as in attainment or nonattainment of the NAAQS. EPA then reviews the state's proposal and determines the final area designations. A designation can also change when a state

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[1] CAA, 42 U.S.C. sections 7408-7409.

[2] EPA has also started to refer to the NAAQS pollutants as "common" pollutants. "Criteria" refers to a detailed document that summarizes what is known about the effects of air pollutants, which is prepared before a NAAQS is established or revised.

finds that a nonattainment area attains the NAAQS and should be redesignated to attainment, or when a state finds that an attainment area does not meet a NAAQS and should be redesignated to nonattainment.

All areas of the country must comply with the NAAQS. Those areas that have monitored ambient air quality concentrations below the NAAQS are considered in compliance with the standard and are called Attainment Areas. Those areas that have monitored ambient air quality concentrations above the NAAQS are in violation of the standard and are called Nonattainment Areas. In either case, states are required to develop policies, rules and control requirements to ensure that all areas of the state meet the NAAQS. When monitoring data shows an area to be in Nonattainment, the state must develop a new State Implementation Plan (SIP) that includes emission reduction requirements needed to demonstrate that air quality would attain the NAAQS in the timelines required by the CAA. Such a nonattainment SIP would include requirements to implement stringent and potentially costly emissions controls to ensure future compliance with the NAAQS.[3]

In the event any areas within Minnesota were to be classified as Nonattainment, the MPCA would have to develop a SIP to address this situation. When developing the SIP, the MPCA would need to address at least the following issues:

- point source emissions inside of the nonattainment area,
- mobile source emissions inside of the nonattainment area,
- area and residential source emissions inside of the nonattainment area, and
- transport of air pollution across state boundaries.

The MPCA in their 2013 report to the Minnesota Legislature[4] stated:

> The majority of air pollutants of most concern today come from smaller wide-spread sources that are not regulated in the way power plants and factories are. These non-point sources include cars, trucks, construction equipment, residential wood burning, and residential garbage burning. The current regulatory structure will not help much with pollution from these sources.

This statement suggests that while further emissions reductions from larger point sources such as Sherco Units 1 and 2 are possible, the primary focus is likely to be on numerous small sources in order to achieve the needed emissions reductions to address the causes of nonattainment should it occur.

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[3] An area can be in attainment of the NAAQS for one or more pollutants, but be in nonattainment of the NAAQS for other pollutants, and, therefore, SIPs are tailored to address emissions on a pollutant-by-pollutant basis as needed to attain the NAAQS.

[4] *Air Quality in Minnesota: 2013 Report to the Legislature*, Summary, MPCA, January 2013.

The MPCA states that Minnesota has a good record in complying with NAAQS and that it is important for the health of Minnesotans and the Minnesota economy to continue meeting these standards. MPCA also points out the following challenge to maintaining NAAQS compliance:

> In 2011, nearly all areas of Minnesota were in compliance with the federal ambient air quality standards. In recent years, the EPA has strengthened or proposed to strengthen the federal ambient air quality standards …. As a result, despite overall improvements in air quality, Minnesota is at some risk for being out of compliance with federal standards for ozone and $PM_{2.5}$.[5]

A description of each NAAQS is provided below, along with a discussion of what pollution control equipment is currently in place on Sherco Units 1 and 2 to address each pollutant. As relevant to the specific NAAQS, there is also discussion of available control technologies, if any, that might be needed for Sherco Units 1 and 2 to comply with present and future NAAQS. The NAAQS are discussed in three groups: particulate matter NAAQS, ozone NAAQS and other NAAQS.

1. Coarse Particulate Matter (PM_{10}) and Fine Particulate Matter ($PM_{2.5}$)

On January 15, 2013, EPA finalized NAAQS for both coarse and fine particulate matter.[6] Fine particulate matter generally refers to particles less than or equal to 2.5 micrometers (μm) in diameter ($PM_{2.5}$). Coarse particulate matter concerns particles between 10 and 2.5 μm in diameter (PM_{10}). EPA lowered the primary (health-based) NAAQS for annual $PM_{2.5}$ from 15 to 12 μg/m^3, and retained the established 24-hour $PM_{2.5}$ standard, which was set at 35 μg/m^3 in 2006. EPA also retained the existing standards for PM_{10}.[7]

EPA established the following timeline for implementation of the new $PM_{2.5}$ NAAQS:

Action	**Timeline**
EPA finalizes revised particle NAAQS	2013
MPCA submits designation recommendations to EPA	2014
EPA designates areas as attainment, nonattainment or unclassifiable	2015
State Implementation Plans due to EPA	2018
Attainment Date (5-10 years after nonattainment designation)	2020-2025

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[5] *Id.* at 4.
[6] *National Ambient Air Quality Standards for Particulate Matter; Final Rule*, 78 *Fed. Reg.* 3086 (Jan. 15, 2013).
[7] EPA established the $PM_{2.5}$ NAAQS in 1997. In 2006, EPA lowered the daily $PM_{2.5}$ standard from 65 μg/m^3 to 35 μg/m^3.

In Minnesota, current monitored air concentrations are below both the 24-hour and the annual primary standard. EPA's current projection is that Minnesota will remain in attainment for the new annual standard for $PM_{2.5}$.[8] However, in 2010, two $PM_{2.5}$ monitors in St. Paul exceeded the daily standard. While fine particle levels have returned to compliant levels, the 2010 exceedances highlight the risk for future nonattainment with the fine particle NAAQS. EPA is expected to designate non-compliant locations by December 2014. We believe Minnesota will remain in attainment for $PM_{2.5}$ based on the latest revisions to the NAAQS described above.

Xcel Energy manages primary particulate matter emissions (particles directly released into the environment) from Sherco Units 1 and 2 with the particulate control devices in place on the units. Specifically, Sherco Units 1 and 2 are equipped with wet scrubbers and wet electrostatic precipitators (WESPs). We do not foresee a need to change the controls that remove particulate matter from the flue gas.

Xcel Energy manages secondary particulate matter emissions (particles created in the air by chemical reactions among other pollutants) from Sherco Units 1 and 2 with the wet scrubber systems for sulfur dioxide (SO_2) emissions and with combustion controls, low nitrogen oxides (NO_X) burners and separated overfire air (SOFA) for NO_X emissions. We believe the scrubber upgrades underway will result by 2015 in SO_2 emission levels that are consistent with recent BACT determinations for SO_2 control technology retrofits, which would be sufficient for fine particle controls as well as SO_2 control requirements of other CAA programs.

Installation of SCR on Sherco Units 1 and 2 could result in lower NO_X emissions, helping to lower secondary particulate matter formation. We do not anticipate having to install SCR for $PM_{2.5}$ purposes unless Minnesota becomes nonattainment for $PM_{2.5}$ in the future. Every five years, EPA reviews the scientific data on health effects and decides whether any revision to the particle NAAQS may be needed. It is not known what adjustments to the particle NAAQS, if any, EPA may make after its next review cycle, which will occur in the 2018-19 timeframe. If the NAAQS were to be made more stringent, and if part of Minnesota were to become nonattainment for the NAAQS, the MPCA would conduct a SIP planning process to assess Minnesota's air quality, evaluate emission reduction options, and impose appropriate emission reduction requirements. If installation of SCRs were to be found necessary to address any future nonattainment of the particle NAAQS, the compliance date would be in

[8] EPA based its projections on 2009-2011 air quality data. For a map released by EPA when it adopted the more stringent annual standard in December 2012, *see* http://www.epa.gov/airquality/particlepollution/2012/20092011map. EPA also released a map showing its projections that all areas of the country will attain the new annual standard by 2020, except some counties in California.

the mid-2020s. It is also possible that Minnesota can avoid nonattainment for particulate matter, resulting in no requirement for additional NO_X controls.

2. *Ozone (O_3)*

Ozone (also called smog) is formed from the reaction of NO_X and volatile organic compounds (VOCs) in the presence of sunlight. As a result, ozone levels are highest in the summer months. In 2008, EPA finalized the current NAAQS for ozone, which is more stringent than the previous ozone NAAQS that was adopted in 1997.[9] The primary NAAQS for ozone consists of an eight-hour standard of 0.075 ppm. Attainment is determined by calculating the annual fourth highest daily maximum eight-hour concentration average over three years. Monitored data in Minnesota shows ozone concentrations at all monitoring sites are below the 8-hour NAAQS. EPA has designated all of Minnesota as in attainment of the 2008 ozone NAAQS.[10]

EPA is working to revise the ozone NAAQS and is expected to propose a new standard in 2013 with expectations that it will be finalized in 2014. We expect the regulatory process to address ozone nonattainment will develop on the following schedule:

Action	Timeline
EPA proposes new ozone NAAQS	2013
EPA finalizes new ozone NAAQS	2014
MPCA submits designation recommendations to EPA	2015
EPA designates areas as attainment, nonattainment or unclassifiable	2016
State Implementation Plans due to EPA	2018-2019
Attainment Date (5-10 years after nonattainment designation)	2021-2026

Depending upon the level of the new standard, portions of Minnesota may not be in attainment with the standard. For example, based on current monitoring data, all of Minnesota might be expected to attain an ozone standard of 0.70 ppm, but parts of Minnesota would likely not attain an ozone standard of 0.60 ppm. If part of Minnesota is designated nonattainment for ozone, MPCA would be required to develop a SIP to achieve further emissions reductions of compounds that contribute to ozone formation on the approximate timeline shown above. Such a SIP would

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[9] *National Ambient Air Quality Standards for Ozone; Final Rule*, 73 *Fed. Reg.* 16436 (March 27, 2008).

[10] *Air Quality Designations for the 2008 Ozone National Ambient Air Quality Standards; Implementation of the 2008 National Ambient Air Quality Standards for Ozone: Nonattainment Area Classifications Approach, Attainment Deadlines and Revocation of the 1997 Ozone Standards for Transportation Conformity Purposes; Final Rules*, 77 *Fed. Reg.* 30088, 30129 (May 21, 2012).

consider reductions needed and possible from many different sources of ozone precursors, and might include Sherco Units 1 and 2.

If Minnesota becomes nonattainment for ozone, MPCA may well target, as part of its SIP, large point sources, like Sherco Units 1 and 2, for further emissions reductions of pollutants that contribute to ozone formation. Sherco Units 1 and 2 can further reduce NO_X emissions through the use of SCR technology. Sherco Units 1 and 2 have minimal VOC emissions and additional controls beyond good combustion practice for VOC control are unlikely. Therefore, if Minnesota does not demonstrate attainment for ozone, Sherco Units 1 and 2 might be required as part of a SIP completed in 2018-2019 to install SCRs for additional NO_X control. The SIP would establish a timeline to complete the installation and start to operate the SCRs by a date in the early to mid 2020s. It is also possible that Minnesota can avoid nonattainment for ozone, resulting in no requirement for additional NO_X controls.

3. Other NAAQS Pollutants

a. Nitrogen Dioxide (NO_2)

In 2010, EPA finalized a revised primary (health-based) NO_2 NAAQS. EPA retained the existing annual average NO_2 NAAQS, and set a new one-hour standard.[11] The one-hour NO_2 NAAQS has a primary (health-based) one-hour standard of 100 parts per billion (ppb). To meet this standard, the three year average of the annual 98th percentile daily maximum one-hour NO_2 concentration must not exceed 100 ppb. Currently, all Minnesota sites meet the annual and one-hour NO_2 NAAQS. EPA completed area designations in early 2012, finding no area in the country to be in nonattainment.[12] The MPCA reported that in 2011, monitors showed concentrations at levels less than half of the levels allowed by the NO_2 NAAQS.[13]

Because NO_2 concentrations near roads are usually higher than at other locations, the new NO_2 NAAQS changed the requirements for state ambient air monitoring networks. EPA recently established a phased schedule for states to amend their monitoring network plans to include near-road monitors, requiring them to be operational between 2014 and 2017. The MPCA will be required to site two near-road monitors, one operational in 2014 and one in 2015. EPA will review the roadside monitoring data after the monitors are deployed for three years. Following

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[11] *Primary National Ambient Air Quality Standards for Nitrogen Dioxide; Final Rule*, 75 *Fed. Reg.* 6474 (Feb. 9, 2010).
[12] *Air Quality Designations for the 2010 Primary Nitrogen Dioxide (NO_2) National Ambient Air Quality Standards*, 77 *Fed. Reg.* 9532, 9563 (Feb. 17, 2012).
[13] *Air Quality in Minnesota: 2013 Report to the Legislature*, at 4, MPCA, January 2013. Nitrogen oxide emissions from point sources declined 49% between 2000 and 2010. *Id.* at 3.

this review, EPA will re-evaluate its designations to determine if any areas do not attain the NO_2 NAAQS.

While current monitoring shows concentrations in Minnesota at 46 percent of the new NAAQS,[14] we anticipate that the near roadside monitors will show higher levels of NO_2 than previously monitored due to mobile source emissions. These higher NO_2 levels may lead to nonattainment with the NO_2 NAAQS. The regulatory process to address NO_2 nonattainment will develop approximately on the following schedule:

Action	Timeline
New NO_2 roadway monitoring begins	2014-2017
EPA issues Nonattainment Redesignations	2017-2018
State Implementation Plans due to EPA	2020
Attainment Date (5-10 years after date of nonattainment)	2022-2027

If Minnesota cannot attain the NO_2 standard, MPCA would have to develop a SIP to address the nonattainment. It is not clear what strategy MPCA would take in this situation, since roadway monitors would record emissions mostly from mobile sources. MPCA's 2013 report[15] shows a 49 percent reduction in point source NO_2 emissions from 2000 to 2010, indicating that point sources, including sources like Sherco Units 1 and 2, are not the primary contributors to any elevated concentrations at a near-road monitoring site. We believe that MPCA would be much more likely to target mobile sources for reductions before they target large point sources, like Sherco Units 1 and 2, for further NO_2 emissions reductions if nonattainment is based on results from a near-road monitor. As such, we do not view the NO_2 NAAQS as likely to result in a requirement for installation of SCRs on Sherco Units 1 and 2.

b. Sulfur Dioxide (SO_2)

EPA revised the primary SO_2 NAAQS in 2010.[16] The primary NAAQS for SO_2 is a one-hour standard with a value of 75 ppb. The primary standard is met if the 99^{th} percentile value of one-hour daily maximum concentrations, averaged over a three-year period, is less than 75 ppb. SO_2 also has a secondary NAAQS, which is a three-hour standard with a value of 0.5 ppm. This standard is not to be exceeded more than once per year. Minnesota is currently in attainment with both of the SO_2

[14] *Id.* at 4.
[15] *Id.* at 3.
[16] *Primary National Ambient Air Quality Standard for Sulfur Dioxide; Final Rule*, 75 *Fed. Reg.* 35520 (June 22, 2010).

NAAQS, with levels at 32% of the standard,[17] and we do not foresee that status changing in the near future. EPA proposed its designations for areas not attaining the SO_2 NAAQS in February 2013, and did not include any areas in Minnesota.[18]

Xcel Energy manages SO_2 emissions from Sherco Units 1 and 2 by using a wet scrubber system to remove SO_2 from the flue gas. Sherco Units 1 and 2 are Best Available Retrofit Technology (BART)-eligible units under the Regional Haze program (see section C). To satisfy our BART obligations, we entered into an Administrative Order to implement additional SO_2 control measures. We are proceeding with the addition of sparger modules to our existing wet scrubbers to further reduce SO_2 emissions from these units, and will complete this work by 2015. We believe these control changes will prove to have emissions equivalent to levels consistent with recent BACT determinations for SO_2 control technology retrofits.

c. Carbon Monoxide (CO)

EPA completed its review of the primary CO NAAQS and published its final determination to maintain the existing standards in 2011.[19] The primary NAAQS for CO has two parts: a one-hour standard and an eight-hour standard. The one-hour standard is 35 parts per million (ppm) while the eight-hour standard is 9 ppm. These standards are not to be exceeded more than once per year. Minnesota is currently in attainment with both of the CO NAAQS, meaning ambient air quality measurements are below the NAAQS. We do not foresee that status changing in the near future.[20]

The Company manages CO emissions from Sherco Units 1 and 2 by maintaining good combustion to minimize formation of CO. Specific pollution control equipment to manage CO emissions is unnecessary. The CO-specific controls available on the market today consist mainly of oxidation catalysts. We do not foresee a time where we would need to add specific CO controls to these units.

d. Lead

In 2008, EPA finalized a new NAAQS for lead that made the standard substantially more stringent.[21] The primary NAAQS for lead consists of a rolling, three-month

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[17] *Air Quality in Minnesota: 2013 Report to the Legislature*, at 4, MPCA, January 2013. Sulfur dioxide emissions from point sources declined 44% between 2000 and 2010. *Id.* at 3.
[18] *EPA Responses to State and Tribal 2010 Sulfur Dioxide Designation Recommendations: Notice of Availability and Public Comment Period*, 78 *Fed. Reg.* 11124 (Feb. 15, 2013).
[19] *Review of National Ambient Air Quality Standards for Carbon Monoxide*, 76 *Fed. Reg.* 54294 (Aug. 31, 2011).
[20] EPA decided that the CO NAAQS, which has remained at the same level since 1971, did not require revision.
[21] *National Ambient Air Quality Standards for Lead; Final Rule*, 73 *Fed. Reg.* 66964 (Nov. 12, 2008).

average which cannot exceed 0.15 micrograms per cubic meter ($\mu g/m^3$). With the exception of a monitoring site located near Gopher Resource Corporation in Eagan, MN, existing lead monitoring sites within Minnesota meet the lead NAAQS of 0.15 $\mu g/m^3$.[22] Between 2000 and 2010, point source lead emissions dropped by 71 percent in Minnesota.[23]

Xcel Energy manages lead emissions from Sherco Units 1 and 2 with the particulate control devices in place on the units. Specifically, Sherco Units 1 and 2 are equipped with wet scrubbers and WESPs. We do not foresee a time where we would need to change the particulate controls that remove lead from the flue gas. We also do not foresee any increases in lead emissions if emissions control technology is added to address any other pollutants (*i.e.*, SCR for control of NO_X).

4. *Assessment of Timing of Potential Future Emission Reduction Requirements as a Result of NAAQS Implementation*

Sherco Units 1 and 2, with their upgraded particle controls and the scrubber upgrades that will be completed by 2015, are expected to have emission performance for particulate matter and SO_2 consistent with recent BACT determinations for control technology retrofits. The combustion controls, low NO_X burners, and overfire air controls put on the units several years ago have substantially reduced NO_X emissions. As a result, the only additional control equipment that could reasonably be anticipated to be required for the units is the addition of SCRs, which would reduce NO_X emissions further.

The revisions to all six NAAQS discussed above were finalized between 2008 and 2012 to reflect the latest scientific information about the health effects of these air pollutants. Despite several NAAQS being significantly tightened, there are at present no nonattainment areas in the state of Minnesota that might result in SIP emission reduction requirements being imposed on Sherco Units 1 and 2. The next timeframe where NO_X emission reductions might be required due to NAAQS nonattainment would be if Minnesota has areas that do not meet the ozone NAAQS as it may be revised in 2014, or goes into nonattainment for particulate matter at some point. According to the NAAQS implementation schedules shown above, further NO_X reductions might be required to be achieved in the early to mid 2020s, but only if Minnesota enters nonattainment.

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22 As cited on page 28 of MPCA's "Annual Air Monitoring Network Plan for Minnesota – 2013"

23 *Air Quality in Minnesota: 2013 Report to the Legislature*, at 3, MPCA, January 2013.

B. Clean Air Act Programs that Address Interstate Transport of Air Pollution

The prior section discussed recent and upcoming revisions to the NAAQS and their potential to result in nonattainment designations in Minnesota. If Minnesota were to fail to attain a NAAQS, the state would be required to develop a SIP that would include emission reduction requirements needed to demonstrate that air quality would attain the NAAQS in the timelines required by the CAA.

In addition, the CAA also provides that SIPs include provisions that prevent sources within the state "from emitting any air pollutant in amounts which will … contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any" NAAQS.[24] EPA has been working to develop programs for the Eastern U.S. that would reduce interstate transport of pollutants that are precursors to two NAAQS pollutants: ozone and fine particles. NO_X is a precursor to ozone and fine particle formation, while SO_2 is a precursor to fine particle formation. For the utility industry, the relevant programs are called the Clean Air Interstate Rule (CAIR) and the Cross-State Air Pollution Rule (CSAPR).

Both CAIR and CSAPR were designed to be "cap and trade" programs that reduce overall emissions from Electric Generating Units (EGUs). This means that total emissions from EGUs in a state or region are limited (the cap), and that each ton of allowed emissions is represented by an emission allowance that can be transferred (the trade). A cap and trade program thus reduces total emissions to the capped amount, but allows EGUs to meet their individual emission reduction requirements through installation of control equipment, purchase of emission allowances from other EGUs, or a combination of both.

Depending on EPA's analysis of an upwind state's emissions impact on nonattainment areas in downwind states, CAIR and CSAPR imposed one or both of the following emission limitations: (1) summer season NO_X, emissions (to address ozone), and/or (2) annual NO_X and SO_2 emissions (to address fine particles). In Minnesota's case, the impact of downwind concern has been fine particle nonattainment areas in downwind states, not ozone.

[24] CAA, 42 U.S.C. section 7410(a)(2)(D)(i)(I).

1. *Regulatory and Litigation History of CAIR*

The CAIR was adopted in 2005, and initially applied to Minnesota for fine particle precursors, requiring reductions in annual NO_X and SO_2 emissions in two stages, 2009 and 2015. The U.S. District Court for the District of Columbia Circuit (D.C. Circuit), however, issued an opinion in 2008 that found the CAIR to contradict the CAA in multiple respects. As a result, the D.C. Circuit reversed and vacated the CAIR.[25] The court later decided to allow the CAIR to be implemented pending EPA's adoption of a replacement program.[26] The CSAPR, described below, was EPA's attempt to adopt a new program to replace the CAIR.

The court's decision, however, found specific errors may have affected EPA's analysis of Minnesota's modeled impact on nonattainment areas in downwind states, and required EPA to respond to this concern. In 2009, EPA adopted a rule that administratively stayed the effectiveness of CAIR in Minnesota, pending further rulemaking in response to the court's remand of the overall CAIR rule.[27] As a result, CAIR is not effective in Minnesota.

2. *Regulatory and Litigation History of CSAPR*

EPA adopted CSAPR in 2011 as the program intended to replace CAIR. The CSAPR, similar to CAIR, would have applied to Minnesota for fine particle precursors, requiring reductions in annual NO_X and SO_2 emissions starting in 2012. On December 30, 2011, however, the D.C. Circuit stayed the effectiveness of CSAPR and instructed the EPA to continue administering CAIR pending the court's resolution of the appeals filed against the CSAPR.[28] On August 21, 2012, the D.C. Circuit issued an opinion finding the CSAPR to contradict the CAA, vacated it, and again instructed the EPA to continue administering the CAIR pending adoption of a valid replacement.[29] In January 2013, the D.C. Circuit denied all requests for rehearing.[30] On June 24, 2013, the U.S. Supreme Court decided to review the case. It

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[25] *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008).
[26] *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008) (on rehearing).
[27] *Administrative Stay of Clean Air Interstate Rule for Minnesota; Administrative Stay of Federal Implementation Plan to Reduce Interstate Transport of Fine Particulate Matter and Ozone for Minnesota*, 74 *Fed. Reg.* 56712 (Nov. 3, 2009).
[28] Order, Case No. 11-1302 (D.C. Cir. Dec. 30, 2011).
[29] *EME Homer City Generation, L.P. v. EPA*, 696 F.3d 7 (D.C. Cir. 2012). NSP-Minnesota appealed the CSAPR, seeking the allocation of additional emission allowances for NSP-Minnesota. NSP-Minnesota contended that the EPA's method of allocating allowances arbitrarily resulted in fewer allowances for its Riverside and High Bridge plants than should have been awarded to reflect their operations during the baseline period, which included coal-fired operations prior to their conversion to natural gas. NSP-Minnesota also requested that EPA reconsider and amend the CSAPR to address this issue. Because of the court's overall ruling on CSAPR, these issues have not been addressed.
[30] Orders, Case No. 11-1302 (D.C. Cir. Jan. 24, 2013).

is likely that the Court will decide the case by June 2014. If the Court affirms the D.C. Circuit's decision, it is not yet known how the EPA might approach a replacement rule. If the Court reverses the D.C. Circuit's decision, the case will likely be remanded to the D.C. Circuit to consider issues that were raised in the litigation but not decided because the issues on which the D.C. Circuit ruled resolved the case. Therefore, it is not known what requirements may be imposed in the future.

3. *Assessment of Timing of Potential Future Emission Reduction Requirements as a Result of Interstate Transport Programs*

Had the CSAPR requirements been applied to Minnesota, Xcel Energy could have met the overall emission limitations imposed on its Minnesota system and would not have needed to install any further controls on Sherco Units 1 and 2. As described above, the installation of combustion controls have resulted in substantial NO_X emission reductions and the scrubber upgrades in progress will achieve substantial SO_2 emission reductions.

If EPA continues to pursue a cap and trade program model, no particular technology is required at any particular time. If EPA shifts, however, to having states develop their own SIPs, then MPCA would evaluate and impose reduction requirements in a future state proceeding. A cap would likely be ratcheted down over time as EPA tightens NAAQS in future NAAQS reviews, but would only apply to Minnesota if Minnesota significantly contributes to downwind nonattainment areas. For SO_2, no additional controls would be required because the scrubber upgrades are expected to result in emission levels consistent with recent BACT determinations for control technology retrofits. For NO_X, installation of SCR on one or both units might be needed, but only if cost-effective compared to: (1) purchasing allowances, or (2) other changes to NSPM's system operations to meet an overall annual emission cap.

The time when additional requirements under the interstate transport program may be imposed is particularly hard to assess. If the Court reverses the D.C. Circuit's decision, the case will likely be remanded to the D.C. Circuit to consider issues raised in the litigation that were not decided because the issues the D.C. Circuit ruled on resolved the case. In this scenario, the litigation would likely continue into 2015. If the Court affirms the D.C. Circuit's decision, it is not yet known how the EPA might approach a replacement rule. It seems likely, however, that development and implementation of a new program could take several years.

C. Clean Air Act Programs that Address Visibility Impairment in National Parks and Wilderness Areas

Visibility impairment is caused when sunlight encounters pollution particles in the air. Some light is absorbed and other light is scattered before it reaches an observer, reducing the clarity and color of what the observer sees, thus impairing visibility. In 1977, the CAA established a national goal of remedying any existing and preventing any future visibility impairment from man-made air pollution in specified "Class I" areas of the United States.[31] "Class I" areas are national parks and wilderness areas, including the Boundary Waters Canoe Area and Voyageurs National Park in Minnesota.

EPA has taken a two-phased approach to implement this program. The first phase was implemented in the 1980s to address visibility impairment "reasonably attributable" to a specific source. This is called "reasonably attributable visibility impairment" or "RAVI." EPA adopted regulations for this program designed to address "plume blight," which is "smoke, dust, colored gas plumes, or layered haze emitted from stacks which obscure the sky or horizon and are relatable to a single source or a small group of sources."[32] After detailed study, EPA made a finding in 1988 that there was no RAVI impairment in Voyageurs National Park.[33]

The second phase was designed to address widespread, regionally homogeneous haze that results from emissions from a multitude of sources. In 1999, EPA adopted its Regional Haze Rule (RHR) to address this type of visibility impairment.[34] State environmental agencies are required to submit SIPs that develop and implement their strategy to reduce emissions that may contribute to regional haze. RHR SIPs also must include reasonable progress goals and periodic evaluation/revision cycles designed to make appropriate progress toward the national goal of no man-made visibility impairment in Class I areas by 2064. State RHR SIPs focus on emissions of SO_2, NO_X and particulate matter. State SIPs will be revised approximately every ten years to continue to take incremental steps that achieve reasonable further progress toward reaching the 2064 national goal.

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[31] CAA, 42 U.S.C. section 7491(a)(1).
[32] *Visibility Protection for Federal Class I Areas*, 45 *Fed. Reg.* 80,084-85 (Dec. 2, 1980).
[33] *Assessment of Visibility Impairments and Integral Vista Identification*, 53 *Fed. Reg.* 35956, 35958 (Sept. 15, 1988).
[34] 40 C.F.R. Sections 51.300 to 51.309 & App. Y. *See Regional Haze Regulations*; Final Rule, 64 *Fed. Reg.* 35714 (July 1, 1999). In 2005, EPA revised its guidelines for control technology determinations under the RHR. This revision followed a court case in which the court concluded, in part, that EPA's prior guidelines did not sufficiently recognize the statutory primacy the CAA gives the states in making control technology retrofit determinations for existing sources. *See American Corn Growers Ass'n v. EPA*, 291 F.3d 1, 6 (D.C. Cir. 2002).

1. *Implementation of the Regional Haze Program in Minnesota*

The MPCA began developing the Minnesota Regional Haze SIP after EPA issued its final BART Guidelines in 2005. In this initial round of Regional Haze SIP development, MPCA was required to identify sources subject to BART requirements and determine what constitutes BART for each source, in addition to the general RHR SIP requirements described above. BART applies to major emission sources in the state that were placed into operation between 1962 and 1977, if they are also found to reasonably contribute to visibility impairment in one or more Class I areas. A "BART Determination" is a case-by-case analysis that "take[s] into consideration the costs of compliance, the energy and non-air quality environmental impacts of compliance, any existing pollution control technology in use at the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."[35] The MPCA identified multiple units in the utility and taconite industries as "subject to BART." For Xcel Energy, the units found subject to BART were Sherco Units 1 and 2.

The MPCA initially determined that the emission restrictions under CAIR would be BART for EGUs. EPA allowed states to decide that the emission reductions to be achieved from EGUs through CAIR would be "better than BART" under the RHR, removing the need for a source-specific control technology determination. After the D.C. Circuit reversed CAIR in 2008 and EPA stayed the effect of CAIR in Minnesota in 2009, the MPCA made source-specific BART determinations for EGUs.

In December 2009, the MPCA approved the Regional Haze SIP for Minnesota, which included selection of the BART controls for Sherco Units 1 and 2. The MPCA concluded that SCRs should not be required because the minor visibility benefits derived from SCRs do not outweigh the substantial costs.[36] The MPCA's BART controls for Sherco Units 1 and 2 consist of combustion controls to reduce NO_X and scrubber upgrades to reduce SO_2. The combustion controls were installed on Sherco Units 1 and 2, and the scrubber upgrades are underway and scheduled to be installed by 2015. MPCA submitted this Regional Haze SIP to EPA for review and approval.

Following its adoption of CSAPR in 2011, EPA determined that the requirements of the CSAPR satisfy the requirements for an approvable "BART Alternative" under the RHR. This rule, as with the rule approving CAIR as BART before it, allows states

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[35] CAA, 42 U.S.C. section 7491(g)(2).
[36] *Regional Haze State Implementation Plan*, at 899-906, MPCA (Dec. 2009).

subject to CSAPR to utilize compliance with CSAPR in lieu of source-specific BART emission limits for EGUs.[37]

In April 2012, the MPCA approved a supplement to its 2009 Regional Haze SIP, finding that the CSAPR meets BART for EGUs in Minnesota. The supplement also included an Administrative Order that established source-specific BART emission limits for Sherco Units 1 and 2 that reflected the MPCA's 2009 determination.[38] In June 2012, the EPA issued its final approval of the Minnesota SIP for EGUs.[39] This included approval of the source-specific emission limits for Sherco Units 1 and 2 as strengthening the SIP, but EPA avoided characterizing them as BART limits.

In August 2012, the National Parks Conservation Association, Sierra Club, Voyageurs National Park Association, Friends of the Boundary Waters Wilderness, Minnesota Center for Environmental Advocacy and Fresh Energy appealed the EPA's approval of the Minnesota SIP to the U.S. Court of Appeals for the Eight Circuit.[40] The court denied intervention in the case to NSP-Minnesota and other regulated parties who petitioned to intervene. It is not yet known how the U.S. Supreme Court's review of the CSAPR may impact the EPA's approval of the Minnesota SIP or the course of this litigation.[41]

Whatever the course of the litigation, MPCA is due to make its five-year progress report on implementation of the Regional Haze SIP in 2014. The MPCA will also be required to revise its SIP by 2018 to consider additional emission reductions that may be necessary to maintain reasonable further progress toward achievement of the national visibility goal by 2064. In this SIP revision, MPCA would be anticipated to consider whether additional control technology should be required for Sherco Units 1 and 2, as well as on multiple other sources of emissions in Minnesota.

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37 *Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans*, 77 *Fed. Reg.* 33642 (June 7, 2012). EPA's conclusion was based on its findings that the CSAPR would result in greater overall reductions from locations not substantially different than would occur under source-specific BART. In addition, EPA's analysis indicated that visibility would not decline in any areas, and that greater overall improvements in visibility would be achieved. As a result, EPA found that CSAPR meets the requirements for a BART Alternative program under the RHR.

38 *Regional Haze State Implementation Plan Supplement*, at 2-3 & App. 2, Administrative Order by Consent, Xcel Energy Sherburne County Generating Station, MPCA (April 2012).

39 *Approval and Promulgation of Air Quality Implementation Plans; Minnesota; Regional Haze*, 77 *Fed. Reg.* 34801 (June 12, 2012).

40 *National Parks Conservation Association (NPCA) et al v. US EPA*, Case Nos. 12-2910 and 12-3481 (8th Cir.).

41 On June 25, 2013, the EPA filed an unopposed motion with the 8th Circuit to hold the Minnesota Regional Haze SIP litigation in abeyance until the Supreme Court decides the CSAPR case.

2. *Implementation of the RAVI Program in Minnesota*

The RAVI program was adopted in the 1980s as the first phase of EPA's visibility program, and was intended to address observable impairment from a specific source such as distinct, identifiable plumes from a source's stack to a Class I area. In 1985, EPA began adopting federal implementation plans (FIPs) for those states that had failed to submit SIPs to implement RAVI. EPA adopted a FIP for Minnesota that included general visibility requirements and long-term strategies, and determined that it was not necessary to revise the FIP for Minnesota to include BART requirements.[42] As part of its administration of the FIP, EPA contemplated that it would develop, review, and revise long-term strategies for Minnesota, starting in late 1987. After detailed study, EPA made a finding in 1988 that there was no RAVI impairment in Voyageurs National Park.[43]

In October 2009, the Department of the Interior certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from Sherco Units 1 and 2. The EPA is required to make its own determination as to whether Sherco Units 1 and 2 cause or contribute to RAVI and, if so, whether the level of controls required by the MPCA is appropriate. The EPA has said that it plans to issue a separate notice on the issue of BART for Sherco Units 1 and 2 under the RAVI program.[44] It is not yet known when the EPA will publish a proposal under RAVI, or what that proposal will entail.

In December 2012, a lawsuit against the EPA was filed in the U.S. District Court for the District of Minnesota by the following organizations: National Parks Conservation Association, Minnesota Center for Environmental Advocacy, Friends of the Boundary Waters Wilderness, Voyageurs National Park Association, Fresh Energy, and Sierra Club.[45] The lawsuit alleges that the EPA has failed to perform a nondiscretionary duty to determine BART for the Sherco Units 1 and 2 under the RAVI program. In initial filings in the case, EPA disputes the plaintiffs' claim. NSP-Minnesota sought leave to intervene in this case, but the Magistrate Judge denied

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[42] *State Implementation Plans for Visibility New Source Review and Monitoring Strategy*, 50 *Fed. Reg.* 28544, 28547 (July 12, 1985) (adopting visibility monitoring requirements for Minnesota); *State Implementation Plans for Visibility Long-Term Strategies, Integral Vistas, and Control Strategies*, 52 *Fed. Reg.* 45132, 45133-34 (Nov. 24, 1987) (adopting visibility long term strategy requirements for Minnesota and deferring decision on control strategies).
[43] *Assessment of Visibility Impairments and Integral Vista Identification*, 53 *Fed. Reg.* 35956, 35958 (Sept. 15, 1988) (after a detailed monitoring study, determining that BART and other control strategies did not need to be adopted in Minnesota).
[44] *Approval and Promulgation of Air Quality Implementation Plans; Minnesota; Regional Haze*, 77 *Fed. Reg.* 34801, 34806 (June 12, 2012).
[45] *NPCA v. US EPA*, Civil Case No. 12-3043 (D. Minn.).

intervention. NSP-Minnesota is now seeking review of that decision with the federal District Court Judge who is assigned to the case.

Xcel Energy vigorously disputes the contention that emissions from Sherco Units 1 and 2 are having a direct RAVI-type impact on the national parks. Sherco Units 1 and 2 were among numerous units found subject to BART under the regional haze program, which is meant to reduce haze that results from the combined emissions of a large number of sources over a broad regional geographic area. RAVI-type impacts are distinct from regional haze. Complex tracer studies and visibility impairment event back trajectory analyses are necessary to determine if any individual source in Minnesota, including multiple sources far closer to the national parks, might have this uncommon impact.

This section need not discuss multiple issues concerning the plaintiffs' contentions that will be disputed in any litigation or proceeding concerning the RAVI program. For purposes of developing scenarios for analysis, we describe below the timing of potential emission reduction requirements based on different potential outcomes of this dispute.

3. *Assessment of Timing of Potential Future Emission Reduction Requirements as a Result of Visibility Programs*

The visibility programs focus on reducing emissions of PM, SO_2 and NO_X as pollutants that can result in visibility impairment. Based on the current level of controls for PM and the upgraded controls for SO_2 at Sherco Units 1 and 2, it is not expected that any further reductions would be required due to implementation of visibility programs. For NO_X, SCR on one or both units might be required at some point to obtain some further emission reductions.

If the litigation on Regional Haze results in new revisions to the SIP, the currently selected controls for Sherco Units 1 and 2 might continue to be required, or the BART determination might be revised to include SCRs on one or both units. If the litigation on RAVI results in a new BART determination process for Sherco Units 1 and 2, the currently selected controls for Sherco Units 1 and 2 might continue to be required, or the BART determination might be revised to include SCRs on one or both units.

The time when additional controls may be required for Sherco Units 1 and 2 is particularly hard to assess. If the Court reverses the D.C. Circuit's decision on CSAPR, the case will likely be remanded to the D.C. Circuit to consider issues raised in the litigation that were not decided because the issues the D.C. Circuit ruled on resolved the case. In this scenario, the litigation would likely continue into 2015. If the Court affirms the D.C. Circuit's decision, it is not yet known how the EPA might approach a replacement rule. It seems likely, however, that development and implementation of a new program could take several years. It is also not known how the EPA might then approach a follow up strategy related to its decisions on regional haze. If CSAPR remains vacated, then the range of time within which SCRs might be required would be about 2018-20 at the earliest. The next interval where SCRs might be required would be about 2023-25.

The earliest time estimate might pertain if EPA: (1) commenced a RAVI proceeding in 2013-14, and determined a new BART for Sherco Units 1 and 2 without performing the required studies to first determine whether the units have a RAVI-type impact, or (2) evaluated the Minnesota Regional Haze SIP in 2014 following a Supreme Court decision that leaves CSAPR overruled, disapproved the MPCA's BART determination, and required SCRs. Sources are generally given up to five years to complete installation of controls after they are required, so if one or both units require SCRs, they would need to be installed and operating by 2018-19 at the earliest.

If SCRs were required as part of the 2018 revisions to the Minnesota Regional Haze SIP, the timeframe for installation and operation would be 2023-25, since the five-year timeline starts when EPA approves the SIP, which usually takes at least two years after the state submits a SIP. Further controls on emission units in the state would be considered as part of each succeeding revision to MPCA's Regional Haze SIP.

D. Electric Utility Hazardous Air Pollutant Regulations

In 2012, the EPA adopted its final rule establishing national emissions standards for hazardous air pollutants (NESHAP) and new source performance standards (NSPS) for coal- and oil-fired power plants. This rule was issued under the CAA and is most often referred to as the Mercury and Air Toxics Standards (MATS). Coal-fired power plants, including Sherco Units 1 and 2, must demonstrate compliance with the rule by April 16, 2015.

Under MATS coal-fired power plants need to meet numerical emission limits for a number of toxic air pollutants, including mercury, non-mercury metals, and acid gases. Plants will need to utilize a variety of control technologies, work practices, and compliance strategies to meet the emission limits.

Sherco Units 1 and 2 are presently equipped with wet scrubbers and WESPs for control of PM, SO_2 and acid gases. We are proceeding with power supply projects to the WESPs in order to improve their performance in terms of additional PM removal efficiency. In addition to these controls, Xcel Energy is in the process of adding sparger modules to the existing wet scrubbers to improve control of SO_2 and acid gases. Finally, the Company intends to install and operate mercury control technology by the end of 2014 to comply with Minnesota mercury reduction requirements (see section E). Once implemented, all of these technologies operating together will reduce emissions of the compounds regulated under MATS to levels well below the numerical limits. Xcel Energy arrived at this suite of pollution control technologies through years of evaluation of technologies to determine which can cost-effectively remove these materials.

E. Minnesota Mercury Emission Reduction Act of 2006

In 2006, the State of Minnesota passed legislation known as the Minnesota Mercury Emission Reduction Act of 2006 (the Act).[46] The Act provides a process for plans, implementation, and cost recovery for utility efforts to curb mercury emissions at certain power plants, including Sherco Units 1 and 2. In December 2009, NSP-Minnesota filed its mercury control plan for Sherco Units 1 and 2 with the MPUC and the MPCA. In October 2010, the MPUC approved the plan, which will require installation of mercury controls on Sherco Units 1 and 2 by the end of 2014. We have proposed to install sorbent injection systems on Sherco Units 1 and 2 to satisfy the Act. The MPCA and the Commission have approved this installation as satisfying the Act and installation is planned for completion prior to December 31, 2014, unless a superior solution is identified that can be implemented by that date.

II. ASH REGULATIONS – COAL COMBUSTION RESIDUALS (CCR)

EPA has been studying coal ash and other wastes associated with the combustion of fossil fuels for over two decades. In 1993 and again in 2000, EPA issued regulatory determinations that large volume wastes including coal ash did not warrant regulation as hazardous wastes. EPA subsequently began considering the need to regulate these materials under a federal program as a non-hazardous industrial waste. EPA accelerated its efforts in this area in late 2008 after the failure of a coal ash impoundment in Tennessee. After that event, EPA also embarked on a nation-wide program to assess the structural integrity of all coal ash impoundments in the country.

On June 21, 2010, EPA published a proposed federal rule for Coal Combustion Residuals (coal ash) for public review and comment.[47] EPA took the unusual step of

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[46] Minn. Stat. sections 216B.68-216B.688.

[47] *Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities; Proposed Rule*, 75 *Fed. Reg.* 35128 (June 21, 2010).

co-proposing three alternative regulatory frameworks in order to solicit comments on all of them at once. The alternatives ranged from regulating coal ash as a listed hazardous waste to managing it in manner equivalent to the way ash is regulated by MPCA in Minnesota today. EPA reportedly received more that 450,000 comments on these proposals and is still evaluating them. On April 5, 2012, a coalition of environmental groups filed a RCRA citizen suit against EPA seeking a court-ordered deadline for a final rule. Other parties joined this litigation as plaintiffs and interveners, but the matter has not yet been decided by the court. In recent legal filings responding to the lawsuit, EPA said they need at least an additional year to complete their review and consideration of all comments before finalizing the rule. We do not anticipate a final rule until the fall of 2014 at the earliest.

In 2012 and again in 2013, bi-partisan legislation was introduced in Congress to address the issue of coal ash management within the framework of a non-hazardous State and Federal regulatory program. The 2013 legislation was recently passed out of the House Energy and Commerce Committee, and a floor vote of the full House could occur this summer. The Senate has not yet taken up similar legislation.

EPA's recent Effluent Limitations Guidelines rule proposal (discussed in the next section) has some overlap with EPA's CCR proposals. EPA is currently soliciting comments on how the coal combustion rules can be aligned to account for any final requirements adopted under the ELG rule.

The long-range impact on Sherco Units 1 and 2 of an eventual federal rule regarding the management and disposal of coal ash is difficult to determine, given the many variables involved. The fly ash and bottom ash disposal ponds at Sherco are well designed and constructed, and already substantially comply with the most likely technical requirements of a prospective federal rule, such as liners and groundwater monitoring systems. In 2010, EPA conducted an inspection of the Sherco ponds and gave them the highest possible rating for safety and structural integrity. Our current view is that the CCR rule, when eventually issued, is not likely to significantly affect Sherco Units 1 and 2 operations in the foreseeable future.

III. WATER REGULATIONS

EPA is currently working on new regulations that will affect power plant water appropriations and discharges, but it is unclear what those regulations may eventually require when finalized in the future. Sherco 1 and 2 are currently equipped with advanced technologies, such as special intake screens to protect fish and small aquatic organisms, closed-cycle cooling towers to minimize water withdrawals and thermal discharges, and closed-loop process water recycling systems to eliminate the need for discharges from ash management and storm water ponds. We believe these systems are likely to meet, or can be adapted to meet, any reasonably foreseeable science and technology based rules. The two most significant rulemaking activities are discussed in the following subsections.

A. Effluent Guidelines

EPA's Effluent Limitation Guidelines (ELGs) are national standards regarding the performance of treatment and control technologies for wastewater discharges to surface waters. The ELGs are issued to specific industry categories, one of which is steam-electric generating plants such as Sherco Units 1 and 2. EPA began the process of updating the rules for steam-electric generating plants in 2009. On June 7, 2013, EPA published a rule proposing new and updated ELGs for steam electric power plants, including the regulation of both wastewater and surface impoundments containing coal combustion residuals.[48] In recognition of the fact that the proposed ELG rule changes involve areas of overlap with the proposed CCR rules, EPA is currently soliciting comment on both.

It has been over 25 years since the ELG guidelines were last updated and there have been advancements in detection, treatment, and control technologies that suggest future reductions in allowable discharge levels are likely. A 2011 EPA Information Collection Request focused heavily on gathering operational information concerning metal cleaning wastes and surface water discharges from wet ash handling systems, and preliminary review of the recently proposed ELG rule signals that EPA intends to tighten requirements in these areas. However, neither of these issues should be of major impact to Sherco 1 and 2 since all process waste water, including ash transport and contact water, are recycled for use in the sulfur dioxide scrubbers and other in-plant systems. The only direct discharge to surface waters from the units is blow-down from the cooling towers, which meets all current discharge requirements and could be treated further if necessary.

We are still reviewing the proposed ELG rule to determine the long-range impact of the ELG rule on Sherco Units 1 and 2. Based on our preliminary review, we believe EPA is likely to receive many substantive legal and technical comments on the proposed rule, suggesting any final rule could be significantly different. In addition, EPA's recent experience with complex rulemaking efforts like this suggest the strong potential for litigation and change after the final rule is issued. Our current view of the ELG rulemaking is that, while it is possible that Sherco Units 1 and 2 may

[48] *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Proposed Rule*, 78 *Fed. Reg.* 34432 (June 7, 2013).

eventually need to make some changes in the way process waste water is managed, it is very unlikely the final rule would significantly impact our ability to continue to operate the two units for the foreseeable future.

B. National Pollutant Discharge Elimination System (NPDES)

EPA continues to develop national regulations governing the design, maintenance, and operation of cooling water intake structures pursuant to Section 316(b) of the Clean Water Act. The intent of 316(b) is to ensure that industrial cooling water intakes are designed and operated to prevent adverse impact to aquatic organisms. EPA began work to update these rules over a decade ago, with the intention of issuing rules for different categories of regulated facilities in phases. In 2004, EPA issued a final "Phase II" rule for large electric generating facilities such as Sherco Units 1 and 2, but that rule was challenged and later remanded back to EPA by the court. EPA is now rewriting the rule in an effort to correct the issues that led to the remand. EPA is doing this work under a Court-ordered deadline and in April 2011 proposed a revised 316(b) Phase II rule which again attracted extensive public comment.[49] EPA then issued two Notices of Data Availability in June of 2012 to allow for public review and comment on new information that had been developed. EPA also requested and received an extension of time from the court and is now scheduled to issue a final rule by June 27, 2013.

The common cooling water intake that supplies Sherco Units 1 and 2 is already equipped with advance screening technology to protect aquatic organisms, and both units are equipped with full capacity cooling towers that allow for closed-cycle cooling operations. The term "closed-cycle" refers to repeated recycling and reuse of the cooling water within the plant system, with only modest withdrawals of fresh water to maintain process water quality and to make up for evaporative losses. With the existing advanced intake screening and closed cycle design, Sherco Units 1 and 2 are likely to substantially meet the requirements of a future 316(b) rule. Our current view is that it is very unlikely the final 316(b) rule will significantly impact our ability to operate the two units for the foreseeable future.

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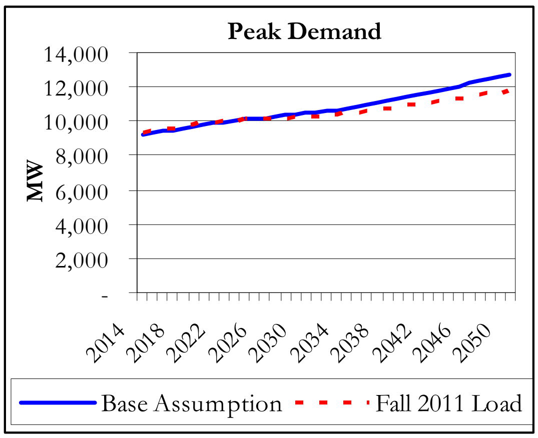
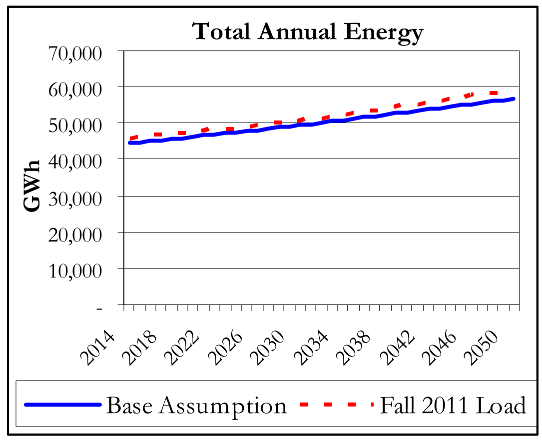
[49] *National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities; Proposed Rule*, 76 *Fed. Reg.* 22173 (April 20, 2011).

Appendix B
Description of Strategist Sensitivities

Sensitivity A – Fall 2011 Load Forecast

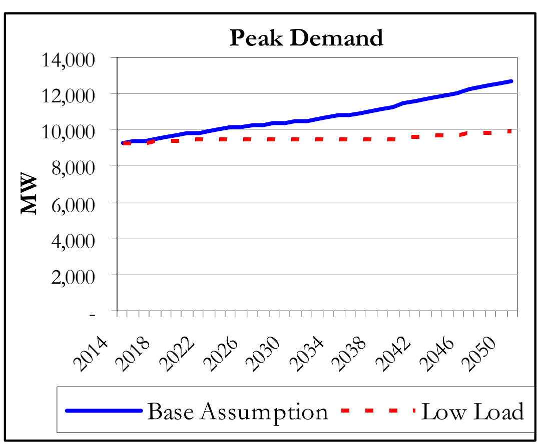
This forecast replaces the Spring 2013 forecast with the load forecast used in our last Resource Plan. This forecast has lower levels of peak demand and higher total energy sales.

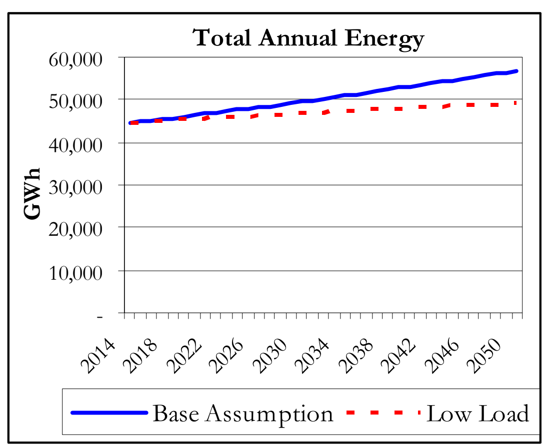




Sensitivity B – Low Load

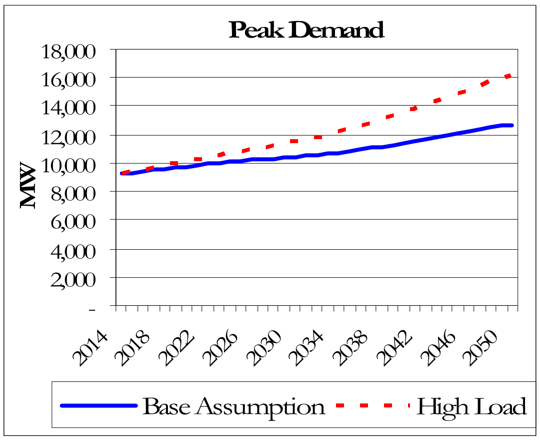
For this sensitivity the growth rates for peak demand and annual sales were decreased by 50%. Under base assumptions, peak demand grows at an average rate of 0.87% and total annual energy at a rate of 0.65%. Under the low load sensitivity, the growth rates for peak demand and annual energy are 0.19% and 0.26% respectively.

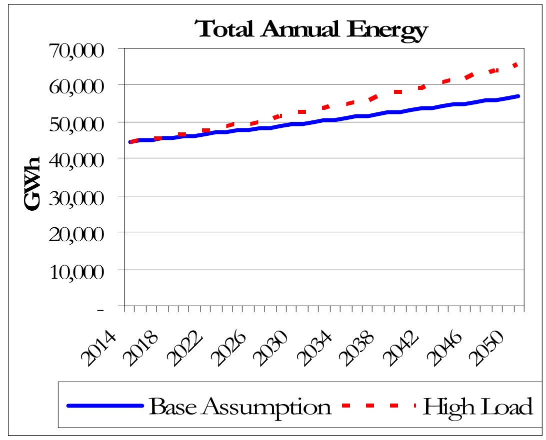




Sensitivity C – High Load

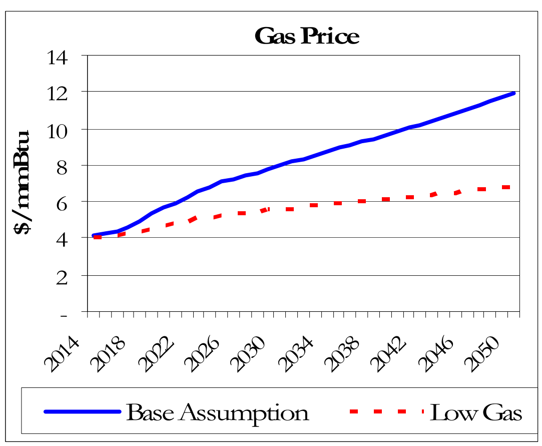
For this sensitivity the growth rates for peak demand and annual sales were increased by 50%. Under base assumptions peak demand grows at an average rate of 0.87% and total annual energy at a rate of 0.65%. Under the high load sensitivity, the growth rates for peak demand and annual energy are 1.54% and 1.04% respectively.





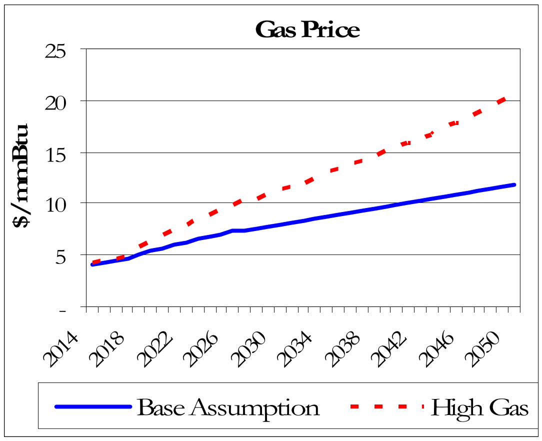
Sensitivity D – Low Gas Prices

For this sensitivity the growth rate for gas prices was decreased by 50%. Under base assumptions, gas prices grow at an average rate of 3.1%. Under the low gas prices sensitivity, the growth rate for gas prices is 1.5%.



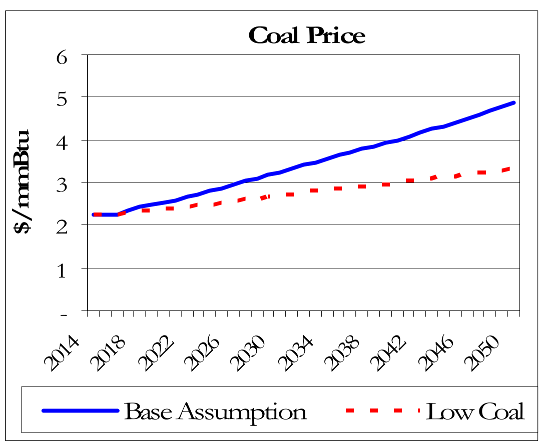
Sensitivity E – High Gas Prices

For this sensitivity the growth rate for gas prices was increased by 50%. Under base assumptions, gas prices grow at an average rate of 3.1%. Under the high gas prices sensitivity, the growth rate for gas prices is 4.6%.



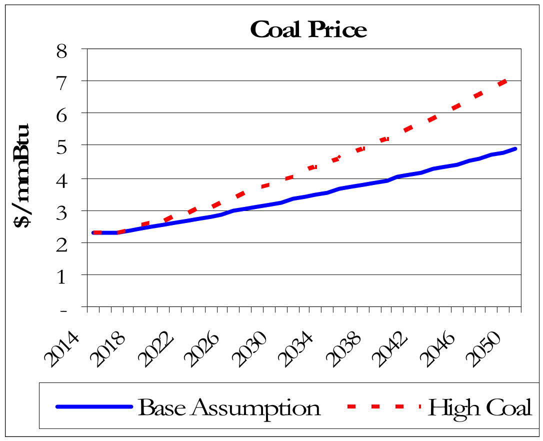
Sensitivity F – Low Coal Prices

For this sensitivity the growth rate for coal prices was decreased by 50%. Under base assumptions, coal prices grow at an average rate of 2.1%. Under the low coal prices sensitivity, the growth rate for coal prices is 1.1%.



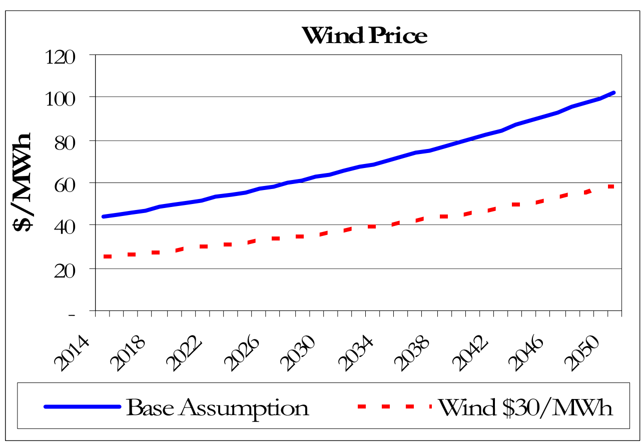
Sensitivity G – High Coal Prices

For this sensitivity the growth rate for coal prices was increased by 50%. Under base assumptions, coal prices grow at an average rate of 2.1%. Under the high coal prices sensitivity, the growth rate for coal prices is 3.2%.



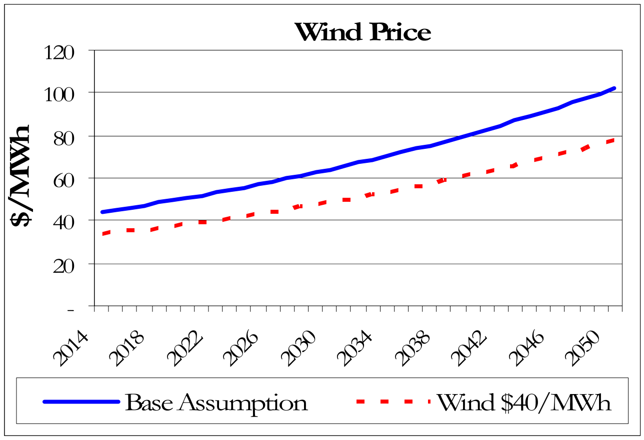
Sensitivity H – Wind $30/MWh Sensitivity

For this sensitivity the levelized price for future wind was decreased to $30/MWh. Under base assumptions, the levelized price for future wind is $52.57/MWh.



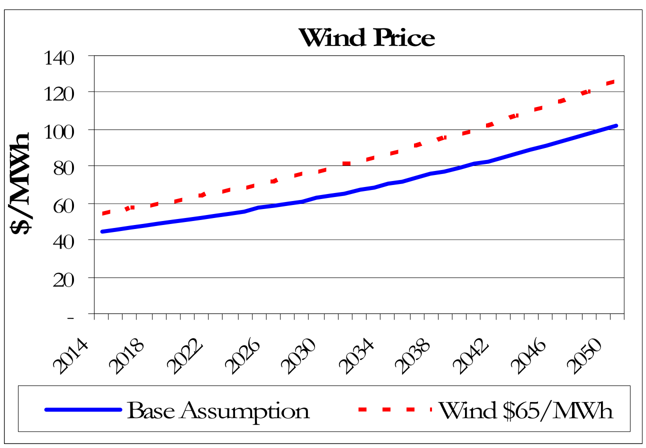
Sensitivity I – Wind $40/MWh Sensitivity

For this sensitivity the levelized price for future wind was decreased to $40/MWh. Under base assumptions, the levelized price for future wind is $52.57/MWh.



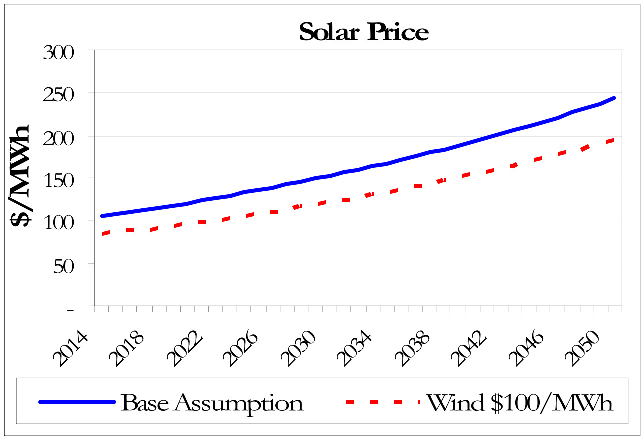
Sensitivity J – Wind $65/MWh Sensitivity

For this sensitivity the levelized price for future wind was increased to $65/MWh. Under base assumptions, the levelized price for future wind is $52.57/MWh.



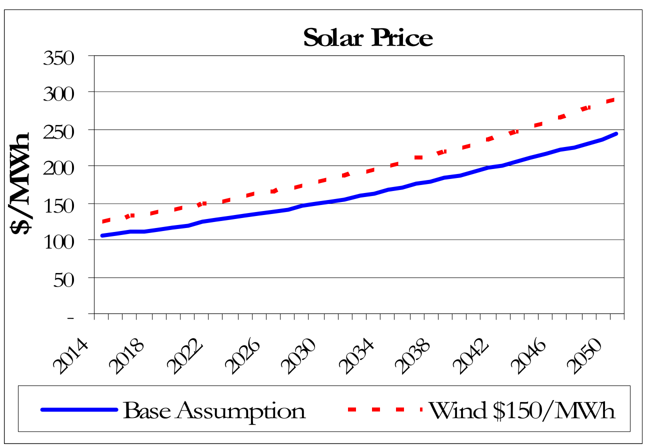
Sensitivity K – Solar $100/MWh Sensitivity

For this sensitivity the levelized price for future solar was decreased to $100/MWh. Under base assumptions, the levelized price for future solar is $125/MWh.



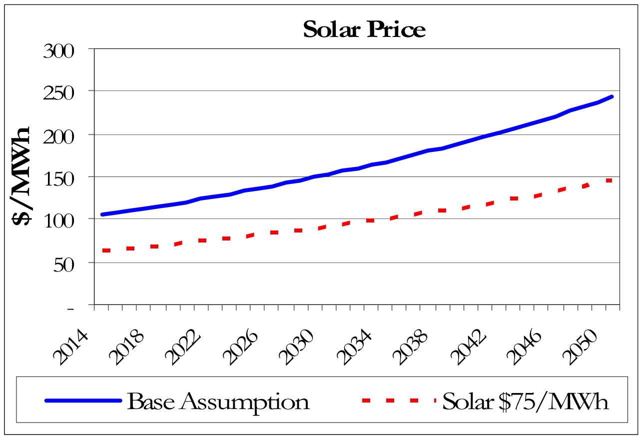
Sensitivity L – Solar $150/MWh Sensitivity

For this sensitivity the levelized price for future solar was increased to $150/MWh. Under base assumptions, the levelized price for future solar is $125/MWh.



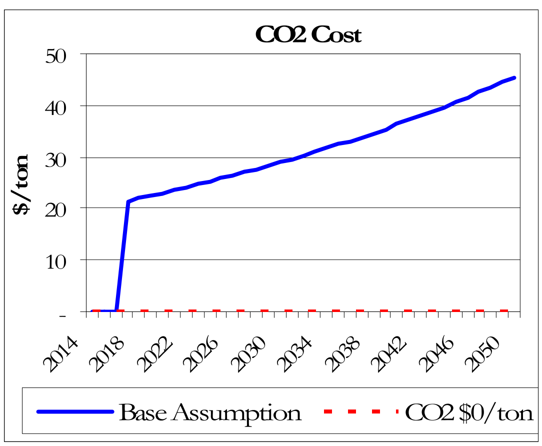
Sensitivity M – Solar $75/MWh Sensitivity

For this sensitivity the levelized price for future solar was decreased to $75/MWh. Under base assumptions, the levelized price for future solar is $125/MWh.



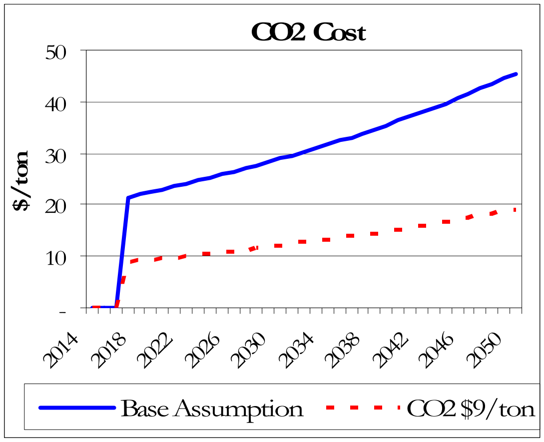
Sensitivity N – CO_2 $0/ton Sensitivity

For this sensitivity the carbon dioxide cost for emissions was decreased to $0/ton. Under base assumptions, the cost for carbon dioxide emissions is $21.50/ton starting in 2017 and escalating at 2.3%.



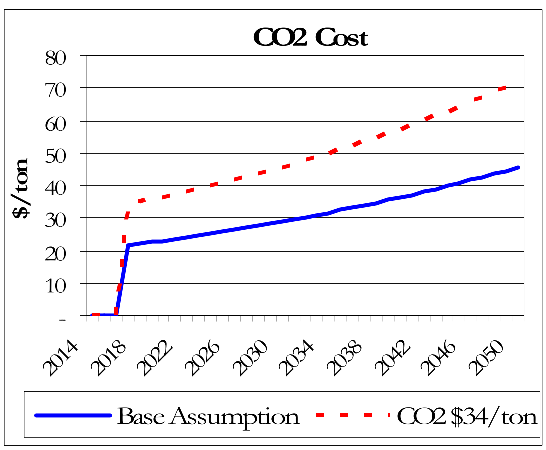
Sensitivity O – CO_2 \$9/ton Sensitivity

For this sensitivity the carbon dioxide cost for emissions was decreased to \$9/ton starting in 2017 and escalating at 2.3%. Under base assumptions, the cost for carbon dioxide emissions is \$21.50/ton starting in 2017 and escalating at 2.3%.



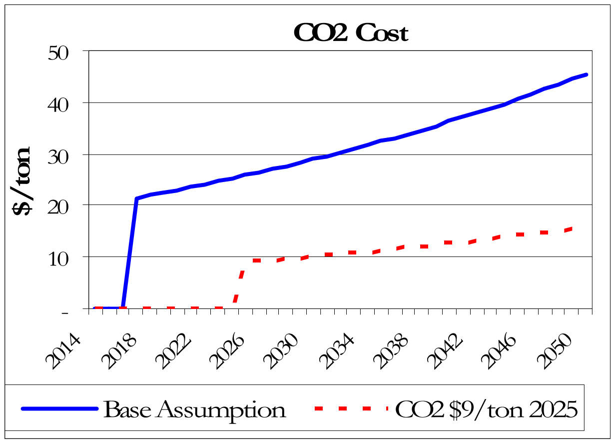
Sensitivity P – CO_2 \$34/ton Sensitivity

For this sensitivity the carbon dioxide cost for emissions was increased to \$34/ton starting in 2017 and escalating at 2.3%. Under base assumptions, the cost for carbon dioxide emissions is \$21.50/ton starting in 2017 and escalating at 2.3%.



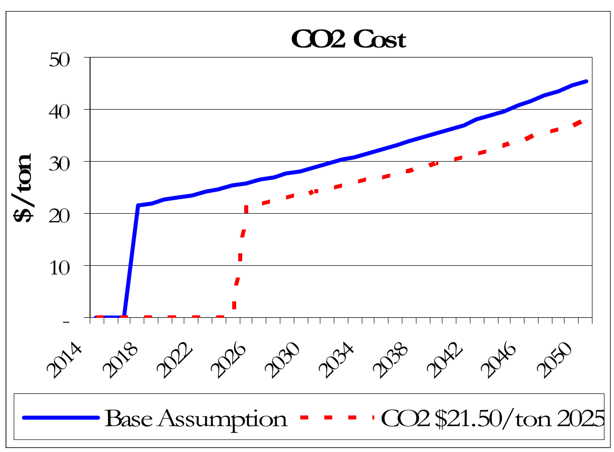
Sensitivity Q – CO_2 \$9/ton 2025 Sensitivity

For this sensitivity the carbon dioxide cost for emissions was decreased to \$9/ton starting in 2025 and escalating at 2.3%. Under base assumptions, the cost for carbon dioxide emissions is \$21.50/ton starting in 2017 and escalating at 2.3%.



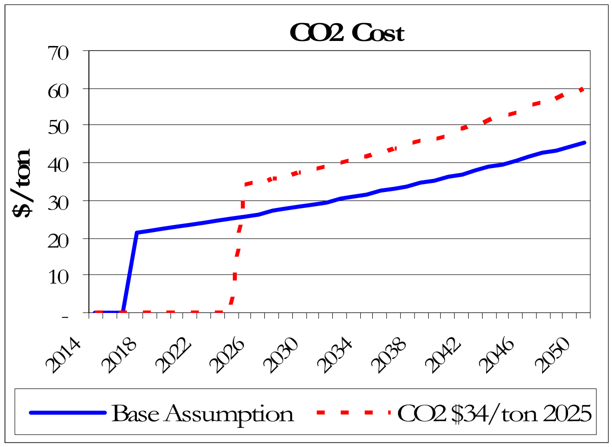
Sensitivity R – CO_2 \$21.50/ton 2025 Sensitivity

For this sensitivity the carbon dioxide cost for emissions was decreased to \$21.50/ton starting in 2025 and escalating at 2.3%. Under base assumptions, the cost for carbon dioxide emissions is \$21.50/ton starting in 2017 and escalating at 2.3%.



Sensitivity S – CO_2 $34/ton 2025 Sensitivity

For this sensitivity the carbon dioxide cost for emissions was increased to $34/ton starting in 2025 and escalating at 2.3%. Under base assumptions, the cost for carbon dioxide emissions is $21.50/ton starting in 2017 and escalating at 2.3%.



Sensitivity T – Sherco +25% Cost Sensitivity

For this sensitivity the costs of fixed O&M, variable O&M, and ongoing capital were increased 25% above the base assumptions. This includes the costs of the fixed O&M and variable O&M of the SCR in applicable cases.

Sensitivity U – SCR +25% Cost Sensitivity

For this sensitivity all costs associated with the SCR including the costs of initial construction capital, ongoing capital, fixed O&M, and variable O&M were increased 25% above base assumptions.

Sensitivity V – CC and CT Cost +25% Cost Sensitivity

For this sensitivity the costs of initial construction capital of new combined cycle and combustion turbine generators that would replace Sherco Units 1 and 2 in a shutdown case were increased 25% above base assumptions.

Sensitivity X – Changed State Policy Sensitivity

This sensitivity includes a high demand side management target, wind generation to meet 30% of forecasted 2030 sales, and solar generation to meet 10% of forecasted 2030 sales.

Sensitivity Y – Markets Off Sensitivity
This sensitivity did not allow any purchases from the MISO market or any other wholesale counterparty. All energy need is self generated.

Sensitivity Z – SCR 10-Year Book Life Sensitivity
This sensitivity reduced the 15-year book life of the SCR to 10 years.

Sensitivity AA – SCR 5-Year Book Life Sensitivity
This sensitivity reduced the 15-year book life of the SCR to 5 years.

Sherco Units 1 and 2 Life Cycle Management Scenarios and Sensitivities

Scenarios - Changes to Sherco and replacement alternatives

	Scenario Name	Sherco 1	Sherco 2	Replacement Generation
1	1 SCR Early - 2 SCR Early	Install SCR 2018 - Retire 2040	Install SCR 2019 - Retire 2040	-NA-
2	1 SCR Late - 2 SCR Late	Install SCR 2024 - Retire 2040	Install SCR 2025 - Retire 2040	-NA-
3	1 Ret Early - 2 SCR Early - Opt	Retire YE 2019	Install SCR 2019 - Retire 2040	Strategist Optimized
4	1 Ret Early - 2 SCR Early - CC	Retire YE 2019	Install SCR 2019 - Retire 2040	Natural Gas Combined Cycle
5	1 Ret Early - 2 SCR Early - CT Wind	Retire YE 2019	Install SCR 2019 - Retire 2040	Natural Gas Combustion Turbine x3 + 800MW Wind
6	1 Ret Early - 2 SCR Early - CT Wind Solar	Retire YE 2019	Install SCR 2019 - Retire 2040	Natural Gas Combustion Turbine x2 + 800MW Wind + 500MW Solar
7	1 Ret Early - 2 SCR Early - CT Wind Solar DSM	Retire YE 2019	Install SCR 2019 - Retire 2040	Natural Gas Combustion Turbine x2 + 600MW Wind + 400MW Solar + 55MW DSM
8	1 Ret Late - 2 SCR Late - Opt	Retire YE 2024	Install SCR 2025 - Retire 2040	Strategist Optimized
9	1 Ret Late - 2 SCR Late - CC	Retire YE 2024	Install SCR 2025 - Retire 2040	Natural Gas Combined Cycle
10	1 Ret Late - 2 SCR Late - CT Wind	Retire YE 2024	Install SCR 2025 - Retire 2040	Natural Gas Combustion Turbine x3 + 800MW Wind
11	1 Ret Late - 2 SCR Late - CT Wind Solar	Retire YE 2024	Install SCR 2025 - Retire 2040	Natural Gas Combustion Turbine x2 + 800MW Wind + 500MW Solar
12	1 Ret Late - 2 SCR Late - CT Wind Solar DSM	Retire YE 2024	Install SCR 2025 - Retire 2040	Natural Gas Combustion Turbine x2 + 600MW Wind + 400MW Solar + 55MW DSM
13	1 Ret Early - 2 Ret Early - Opt	Retire YE 2019	Retire YE 2020	Strategist Optimized
14	1 Ret Early - 2 Ret Early - CC	Retire YE 2019	Retire YE 2020	Natural Gas Combined Cycle x2
15	1 Ret Early - 2 Ret Early - CT Wind	Retire YE 2019	Retire YE 2020	Natural Gas Combustion Turbine x5 + 3,000MW Wind
16	1 Ret Early - 2 Ret Early - CT Wind Solar	Retire YE 2019	Retire YE 2020	Natural Gas Combustion Turbine x3 + 2,200MW Wind + 1,200MW Solar
17	1 Ret Early - 2 Ret Early - CT Wind Solar DSM	Retire YE 2019	Retire YE 2020	Natural Gas Combustion Turbine x3 + 2,000MW Wind + 1,100MW Solar + 55MW DSM
18	1 Ret Late - 2 Ret Late - Opt	Retire YE 2024	Retire YE 2025	Strategist Optimized
19	1 Ret Late - 2 Ret Late - CC	Retire YE 2024	Retire YE 2025	Natural Gas Combined Cycle x2
20	1 Ret Late - 2 Ret Late - CT Wind	Retire YE 2024	Retire YE 2025	Natural Gas Combustion Turbine x5 + 3,000MW Wind
21	1 Ret Late - 2 Ret Late - CT Wind Solar	Retire YE 2024	Retire YE 2025	Natural Gas Combustion Turbine x3 + 2,200MW Wind + 1,200MW Solar
22	1 Ret Late - 2 Ret Late - CT Wind Solar DSM	Retire YE 2024	Retire YE 2025	Natural Gas Combustion Turbine x3 + 2,000MW Wind + 1,100MW Solar + 55MW DSM
23	"Reference Case"	Business as usual with retirement in 2040	Business as usual with retirement in 2040	-NA-

Sensitivities - Changes to input assumptions, ran for all scenarios

	Sensitivity	
a	Load - Fall 2011	Forecast from the Resource Plan
b	Low Load	50% of base case growth rate
c	High Load	150% of base case growth rate
d	Low Gas Prices	50% of base case growth rates
e	High Gas Prices	150% of base case growth rate
f	Low Coal Prices	50% of base case growth rates
g	High Coal Prices	150% of base case growth rate
h	Wind $30	$30/MWh levelized price
i	Wind $40	$40/MWh levelized price
j	Wind $65	$65/MWh levelized price is approximately equal to 'no PTC'
k	Solar $100	$100/MWh levelized price
l	Solar $150	$150/MWh levelized price
m	Solar $200	$200/MWh levelized price
n	CO2 $0	$0/ton - note base case is $21.50
o	CO2 $9	$9/ton in 2017 escl @ inflation
p	CO2 $34	$34/ton in 2017 escl @ inflation
q	CO2 $9 2025	$9/ton in 2025 escl @ inflation
r	CO2 $21.50 2025	$21.50/ton in 2025 escl @ inflation
s	CO2 $34 2025	$34/ton in 2025 escl @ inflation
t	Sherco Cost +25%	125% of FOM, VOM, & Ongoing Capital
u	SCR Cost +25%	125% of Capital Cost & Ongoing Costs
v	CC & CT Costs + 25%	125% of Constuction Capital
x	Changed State Policy	10% Solar 35% Wind 5% other by 2030
y	Markets Off	Disable market pruchases in the model
z	SCR 10yr Depr	Accelerated depreciation of SCR 10yrs
aa	SCR 5yr Depr	Accelerated depreciation of SCR 5yrs

Appendix C
Review of Externality Values Based on Those Used by the Minnesota Public Utilities Commission and the Federal Government for Regulatory Impact Analyses

I. INTRODUCTION

The Commission requested that scenarios analyzed include "[a] range of updated externality values based on those used by this Commission and the federal government for regulatory impact analyses."[1] The scenarios presented by Xcel Energy in this study include the Commission's latest approved proxy values for carbon dioxide (CO_2) and the Commission's latest updated environmental externality values for other air pollutants. In this Appendix we discuss values reflecting federal government estimates of externality values for CO_2 that were developed for use in Regulatory Impact Analyses (RIAs) and values taken from a study conducted by the National Research Council (NRC).

We are not aware of any process undertaken at the federal level similar to that undertaken by the Commission to establish Minnesota's externality values. However, RIAs have been conducted by the Environmental Protection Agency (EPA) in conjunction with federal rulemakings. We investigated externality values in several of the most recent EPA rulemaking dockets to determine if there were values established that could be applied in the same way the Commission's environmental values are applied. We provide our analysis below and discuss how once National Ambient Air Quality Standards (NAAQS) have been established through RIAs, the associated externalities are eliminated or minimized, because NAAQS are set to protect human health and welfare without consideration of costs.

Other than for CO_2 emissions, which reflect generalized global impacts, the pollutants that are the subject of federal regulation have local or regional impacts. In the past 15 years, these pollutants have been the target of increasingly stringent regulations that have required emission reductions or compliance with ambient concentrations that seek to eliminate or minimize externalities associated with emissions of such pollutants. RIAs are conducted in an attempt to assess the macro benefits that may result from the specific emission reductions required by each individual final rule. The focus of an RIA is on the measurement of the benefits that may arise from a requirement to install pollution controls or to implement programs that will reduce emissions and, in some instances, general estimates of the costs associated with the

[1] Order Establishing Procedural Schedules and Filing Requirements at 11, *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*, Docket No, E-002/RP-10-825 (Nov. 30, 2012).

reductions. Because these analyses are general in nature, Xcel Energy was unable to identify consistent, appropriate, and relevant externality values to apply at the local level.

Xcel Energy asked the Environmental Intervenors in this proceeding for suggestions on a source of federal externality values we should consider and were referred to a study by the NRC entitled *The Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use*. While this study was not used as a basis for any EPA air quality regulations affecting NAAQS or limiting emissions of criteria air pollutants from the utility industry, we did examine the study to develop cost values to use in modeling scenarios.

In this Appendix we:

- review the Commission's development of environmental externality and carbon regulation proxy costs;
- present carbon dioxide externality values that have been developed by the federal government to assist in preparation of RIAs, noting that while these values have recently been updated, we believe they are too high;
- discuss the use of recent EPA RIAs associated with regulations addressing criteria pollutants and values from the NRC Report to estimate externality values for Minnesota facilities; and
- characterize the cost impacts of including these values.

II. COMMISSION ENVIRONMENTAL EXTERNALITY VALUES AND CARBON PROXY COSTS

The scenarios presented in this study include the environmental externality costs developed by the Commission. The Commission established its environmental cost values following extensive, contested proceedings that lasted more than two years.[2] As part of establishing these cost values, the Commission had to consider and decide several related conceptual issues.

First, the Commission decided it would base its range of values on "as many effects of by-products of generation as practical," focus on "the effects of by-products that cause the most significant costs," and "concentrate on the impacts that are easiest to quantify."[3] The Commission therefore concentrated on the six NAAQS pollutants,

[2] Order Establishing Environmental Cost Values, Procedural History at 1-4, *In the Matter of the Quantification of Environmental Costs Pursuant to Laws of Minnesota 1993, Chapter 356, Section 3*, Docket No. E-999/CI-93-583 (Dec. 16, 1996) (noting that in several weeks of evidentiary hearings, over 50 witnesses presented testimony).
[3] *Id*. at 12.

mercury, and CO_2.[4] While noting that under the Clean Air Act (CAA), the NAAQS are to be set to protect public health with an adequate margin of safety, because EPA had not revised the NAAQS for many years, the Commission established cost ranges for these pollutants.[5]

Next, the Commission found the damage-cost approach to be superior, but noted that although it has shortcomings, the cost of control method "may be reasonable in certain circumstances. In some instances, it may be much easier or less expensive to estimate control costs than to estimate actual damages."[6] In establishing its environmental externality cost ranges, the Commission decided that "[w]ith the exception of the values for CO_2, which causes damages globally rather than regionally or locally, the Commission has quantified the costs of environmental damage occurring in Minnesota."[7]

Since first establishing the environmental cost values, the Commission has updated them using the Gross Domestic Product Price Deflator Index. The most recent externality values were issued by the Commission on June 13, 2012.[8] These values were used in the scenarios presented in this study. Since the establishment of the Minnesota externality values, emissions have decreased considerably from the power sector and many other types of emission sources, thereby reducing impacts on the environment. Due to these significant reductions, the externality values in use today in Minnesota may overestimate the impact of a ton of pollutant emitted, making the high end of the range a conservative estimate. However, because the Commission values were developed based on conditions specific to Minnesota, we believe these are the most representative values to use in an analysis such as the Sherco 1 and 2 study.

To address uncertainty over how carbon regulation may develop, Minn. Stat. § 216H.06 requires the Commission to establish an estimate of the likely range of costs of future CO_2 regulation on electricity generation, and to update the estimates annually following informal proceedings. After section 216H.06 became effective in 2007, the Commission made its initial estimates of the cost per ton of CO_2 emissions that carbon regulation might cost. The Commission also found that utilities did not

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[4] *Id.* at 13. The Commission distinguished the generic nature of externality cost estimates from the specific circumstances of the resource options proposed in future individual planning dockets.
[5] *Id.* At 16.
[6] *Id.* at 14.
[7] *Id.* at 15. The Commission used a detailed, Minnesota-specific study to establish its environmental cost ranges. *Id.* at 17.
[8] Notice of Updated Environmental Externality Values, *In the Matter of the Investigation into Environmental and Socioeconomic Costs*, Docket Nos. E-999/CI-93-583 and E-999/CI-00-1636 (June 12, 2012).

need to continue to utilize the externality cost for CO_2 if they instead applied the carbon regulation costs.[9]

The carbon proxy cost is intended as a planning tool to estimate how future regulation of CO_2 emissions may affect the cost of generating electricity. The Commission's most recent order maintained the estimate of the range of likely costs of CO_2 regulation at between $9 and $34 per ton of CO_2 for 2012 and 2013. Utilities must apply the range of CO_2 values in their resource planning as of 2017.[10] The Company used carbon proxy costs of $9, $21.50 and $34 per short ton in this analysis.

III. CARBON DIOXIDE EXTERNALITY COSTS DEVELOPED BY FEDERAL GOVERNMENT AGENCIES FOR USE IN REGULATORY IMPACT ANALYSES

In 2010, an inter-governmental group consisting of EPA, the Department of Energy and ten other agencies developed a "Social Cost of Carbon for Regulatory Impact Analysis," which provides estimates for the social cost of carbon (SCC) to estimate the climate benefits of rulemakings. In this report, the Working Group states: "The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change."[11] The Working Group also states that, "to address the global nature of the problem, the SCC must incorporate the full (global) damages caused by greenhouse gas (GHG) emissions."[12] In other words, the SCC is developed based on damages globally, not domestically. In various regulations that use the SCC, such as EPA's light-duty vehicles GHG proposed rule, the SCC has been part of the standard public comment process. In May 2013, the Interagency Working Group updated the SCC values.[13]

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[9] Order Establishing Estimate of Future Carbon Dioxide Regulation Costs, at 4 and Ordering Para. 3, *In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes §216H.06*, Docket No. E-999/CI-07-1199 (Dec. 21, 2007).
[10] Order Establishing 2012 and 2013 Estimate of Future Carbon Dioxide Regulation Costs, at 4, *In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes §216H.06*, Docket No. E-999/CI-07-1199 (Nov. 2, 2012).
[11] *Technical Support Document: - Social Cost of Carbon for Regulatory Impact Analysis-Under Executive Order 12866*, page 2, February, 2010.
[12] *Id.* at 10.
[13] *Technical Support Document: - Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis- Under Executive Order 12866*, May 2013.

On its website, the EPA states:

> The interagency group selected four SCC values for use in regulatory analyses. The first three values are based on the average SCC from the three integrated assessment models, at discount rates of 5, 3, and 2.5 percent. SCCs at several discount rates are included because the literature shows that the SCC is highly sensitive to discount rate and because no consensus exists on the appropriate rate to use for analyses spanning multiple generations. The fourth value is the 95th percentile of the SCC from all three models at a 3 percent discount rate, intended to show the potential for higher-than-average damages.

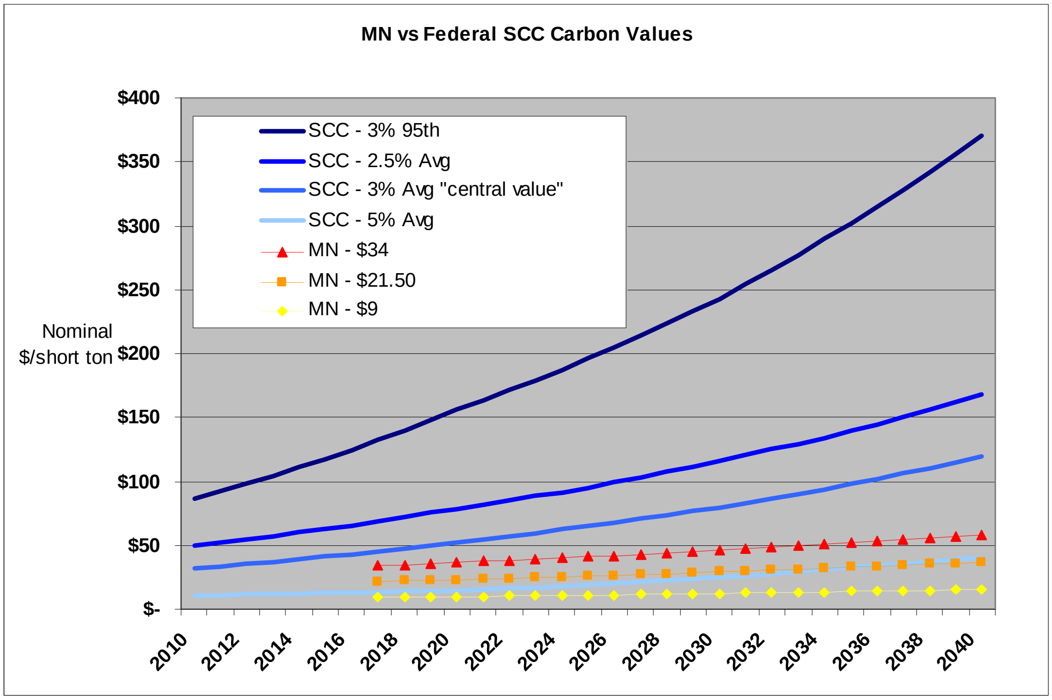
The updated SCC values from May 2013 are shown below:

Social Cost of CO_2, 2015-2050[a] (in 2007 Dollars)

	Discount Rate and Statistic			
Year	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th percentile**
2015	$12	$38	$58	$109
2020	$12	$43	$65	$129
2025	$14	$48	$70	$144
2030	$16	$52	$76	$159
2035	$19	$57	$81	$176
2040	$21	$62	$87	$192
2045	$24	$66	$92	$206
2050	$37	$71	$98	$221

[a] The SCC values are dollar-year and emissions-year specific.

The figure below summarizes the carbon regulation proxy costs established by the Commission and the SCC values estimated by the federal interagency group.



The Company included the two middle SCC values – SCC – 2.5% Avg and 3% Avg "central value" – in its analysis. The SCC-5% Avg value was not run because it falls within the range of the Commission's values. The SCC-3% 95th values were not run because these values are significantly out of the range of costs expected to be imposed by reasonable climate policy that could be adopted in the near term.

Furthermore, the Company does not believe that the values from the SCC – 2.5% Avg and 3% Avg "central value" are likely outcomes of any potential federal carbon policy. Those scenarios assume a carbon cost of $45 and $68 per ton in 2017, respectively, which are considerably higher than values developed through the Commission's stakeholder process to establish environmental costs.

As evidence, we discuss two recent carbon policy proposals that garnered the most attention by Congress in recent years. The American Clean Energy and Security Act of 2009 (ACES) and the American Power Act. Both policies estimated lower carbon compliance prices than the two middle SCC values, and neither policy moved forward, in part due to cost concerns.

In 2009, the American Clean Energy and Security Act of 2009 (ACES)[14] was passed by the U.S. House of Representatives. The chart below, taken from the Congressional Research Service's report prepared for members and committees of Congress,[15] shows allowance prices estimated under ACES, in 2005 dollars. The table following the chart shows the SCC values in 2005 dollars. The 2.5% and 3% values are significantly higher than all but one scenario considered for the congressional report.

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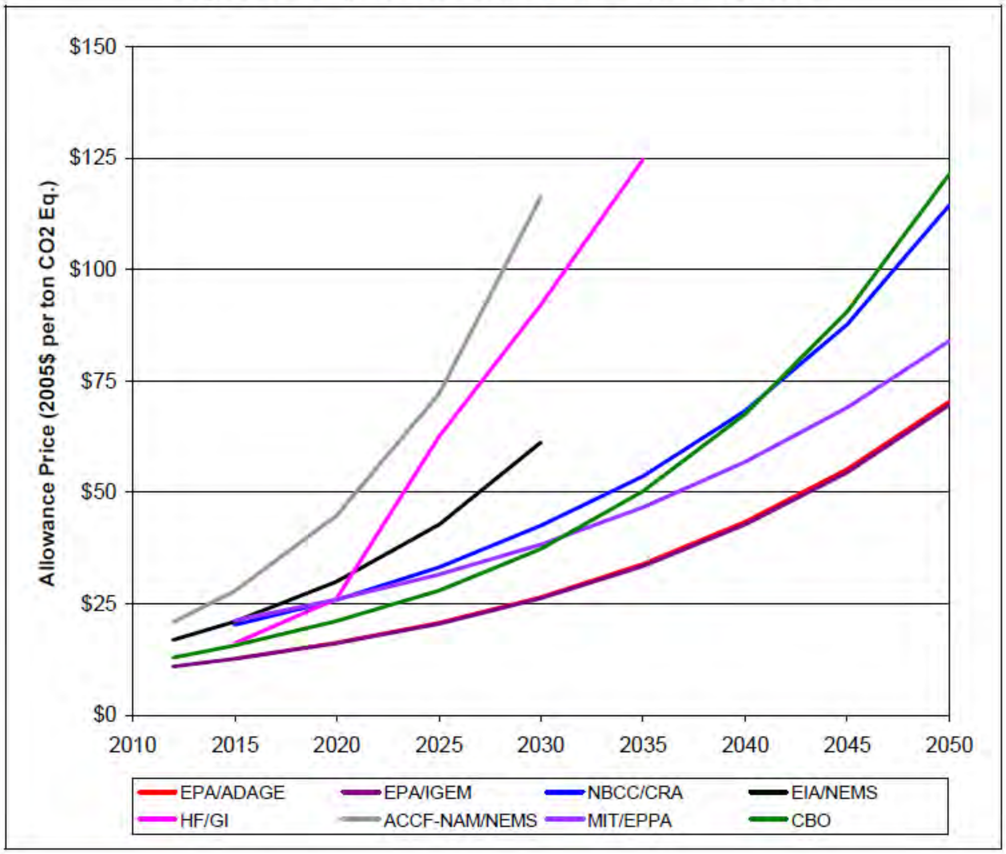
[14] American Clean Energy and Security Act of 2009, H.R. 2454, 111th Congress, 1st Session.

[15] *Climate Change: Costs and Benefits of the Cap-and-Trade Provisions of H.R. 2454*, Congressional Research Service, Parker, Larry and Yacobucci, Brent, September 14, 2009.

Figure 12. Projected Allowance Prices Under H.R. 2454



Sources: EPA/ADAGE and EPA/IGEM: "Data Annex" available on the EPA website at http://www.epa.gov/climatechange/economics/economicanalyses.html MIT/EPPA: Sergey Paltsev, et al., "Appendix C" of Paltsev et al., *The Cost of Climate Policy in the United States*, MIT Joint Program on the Science and Policy of Global Change (2009). EIA/NEMS: EIA, *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009*, (August 2009). ACCF-NAM/NEMS: SAIC, *Analysis of The Waxman-Markey Bill "The American Clean Energy and Security Act of 2009" (H.R. 2454) Using The National Energy Modeling System (NEMS)*, report by the ACCF and NAM (2009). NBCC/CRA: CRA International, *Impact on the Economy of the American Clean Energy and Security Act of 2009 (H.R. 2454)* (May 2009). CBO: CBO, *CBO Cost Estimate: H.R. 2454 American Clean Energy and Security Act of 2009 As ordered reported by the House Committee on Energy and Commerce*, (June 5, 2009). HF/GI: The Heritage Center for Data Analysis, *The Economic Consequences of Waxman-Markey: An Analysis of the American Clean Energy and Security Act of 2009* (August 5, 2009).

Note: Estimates converted to 2005$ using GDP implicit price deflator.

Revised Social Cost of Carbon from "May 2013" update, Technical Support Document				
Cost per ton, CO_2, 2005 dollars				
	5% Avg	3% Avg	2.5% Avg	3% 95th
2020	$12	$43	$65	$129

In 2010, the Senate proposed a similar GHG proposal, the American Power Act.[16] This proposal contained a cost containment mechanism for emission allowances, which would have been used to comply with the standard. This mechanism would likely not have allowed the allowance price to reach the $40 per ton level, which is lower than the two SCC scenarios indicate.[17] This Senate proposal stalled, and the new Congress elected in 2010 had a stronger opposition to cap and trade policies.

Because compliance costs were a main reason these proposals were opposed, we do not anticipate that carbon policies in the near future will have higher costs than the proposals Congress has most recently considered. Thus, we do not believe the SCC costs are reasonable to use in resource planning analysis, but believe the Commission's estimates of the cost of future carbon regulation are more appropriate.

IV. EPA REGULATORY IMPACT ANALYSES ASSOCIATED WITH RECENT AIR QUALITY REGULATIONS

Xcel Energy was asked to consider the results of EPA RIAs associated with recent air quality regulations. The purpose of regulation is to reduce or minimize externality costs imposed on society by establishing standards with which sources must comply. Such regulations either require emission reductions, impose control costs on sources to eliminate the externality or impose taxes to internalize externality costs (either directly or through a cap and trade program). EPA uses RIAs in its rulemakings to comply with an Office of Management and Budget (OMB) requirement to compare the estimated cost of achieving newly-required emission reductions with the estimated benefits that may be realized.

Xcel Energy reviewed EPA's RIAs in an attempt to find applicable cost-benefit values that could be used in this analysis. This section first reviews recent EPA regulatory actions, focusing on the suite of revised NAAQS and new regulations that impact emissions of NAAQS pollutants. This section then analyses the RIAs EPA prepared in association with these emission reduction rules.

A. EPA's Recent NAAQS Revisions and Significant Air Quality Regulations

Under the Clean Air Act, the EPA is obligated to establish NAAQS for a wide range of pollutants.[18] After the CAA was enacted in 1970, EPA adopted NAAQS for five pollutants: particulates, ozone, sulfur dioxide, nitrogen dioxide, and carbon

[16] American Power Act, Section 726, May 2010 (Senators Kerry and Lieberman) (not enacted).
[17] We estimate that under this proposed legislation, the allowable allowance price would reach a maximum of $35 per short ton in nominal terms, if escalated at 7% per year. The bill specified that the allowance price can rise at 5% plus the rate of inflation, which we have estimated as 2% per year.
[18] The NAAQS program is described in Appendix A, section I.A.

monoxide.[19] In setting the NAAQS for these pollutants, EPA is obligated to set the standards at levels that, "in the judgment of the Administrator, based on such criteria and allowing an adequate margin of safety, are requisite to protect the public health."[20]

Importantly, these NAAQS are set without regard to costs: they must simply be set at levels that protect public health and welfare.[21] Once EPA establishes the NAAQS, each state is obligated to develop regulations to achieve them, through regulations that impose emission reduction or control requirements or that establish emission trading programs that internalize the costs of pollution. As described in detail in Appendix A, Minnesota currently meets all NAAQS, including the particulate matter NAAQS revised by EPA in early 2013.[22]

At the time of the Commission's extensive proceeding in the mid-1990s that established the environmental externality values for Minnesota resource planning purposes, EPA had either not reviewed or not revised the NAAQS for many years. This led the Commission to establish externality values for the NAAQS pollutants. Adopted in 1971, the NAAQS were not revised until the late 1970s, when EPA added a NAAQS for lead in 1978, and made the ozone NAAQS less stringent in 1979. In 1987, EPA adopted a NAAQS for particulate matter less than 10 microns (PM_{10}). Since 2008, EPA has concluded comprehensive scientific reviews for every NAAQS pollutant, with standards being made more stringent for all pollutants except for carbon monoxide. EPA has reviewed and revised the particulate NAAQS three times, the latest in 2013, and the ozone NAAQS twice since 1997. For the first time since the early 1970's, every NAAQS has been subject to a full scientific review within the last five years. The most recent NAAQS revisions and Minnesota's status with respect to attainment of the current NAAQS are described in Section I.A of Appendix A.

At the same time that EPA has been reviewing and revising the NAAQS, EPA has also adopted numerous air quality regulations that are focused on reducing criteria and hazardous air pollutants from mobile sources and multiple categories of stationary sources. The numerous air quality regulations directed at reducing emissions from the

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[19] *See* www.epa.gov/ttn/naaqs, which includes tables showing the year review was completed and the resulting NAAQS for each pollutant.
[20] *See e.g.* 42 U.S.C. §7409. The administrator also must set secondary ambient standards that are necessary to "protect the public welfare from any known or anticipated adverse effects associated with the presence of such air pollutant in the ambient air." See 40 U.S.C. §7409(b)(1) - (2).
[21] See *id*, and *Whitman v. American Trucking Assocs., Inc.*, 531 U.S. 457 (2001) (CAA does not allow EPA to consider costs in setting NAAQS).
[22] The MPCA submitted a SIP to EPA in June 2012 that addresses the lead nonattainment area in Eagan, Minnesota by requiring new controls for Gopher Resource Corporation, a lead smelter and battery recycler. MPCA reports that current monitoring shows ambient lead concentrations to be below the NAAQS. *See* http://www.pca.state.mn.us/index.php?option=com_k2&Itemid=2851&id=2585&layout=item&view=item

utility sector are described in Appendix A. In addition, a suite of mobile source regulations has been adopted, which include emission reduction requirements from cars and light duty trucks; heavy duty trucks, buses and engines; motorcycles; aircraft; diesel boats and ships; gasoline boats and personal watercraft; non-road diesel equipment; locomotives, lawn and garden equipment; and snowmobiles and ATVs. EPA has also recently adopted standards regulating new and existing stationary diesel generators and new and existing commercial, industrial, and institutional boilers and solid waste incinerators.

As a result of these multiple NAAQS revisions and air quality regulations, significant emission reductions have occurred. Without these reductions these impacts would have been previously treated as externalities. They have now however, become internalized through the costs incurred to meet the new, more stringent requirements.

B. Regulatory Impact Analyses Associated with EPA's NAAQS Revisions and Significant Air Quality Regulations

The White House, through Executive Order 12866 (Order), requires agencies to perform cost-benefit analyses of all "significant" rules and to submit these analyses to the Office of Management and Budget (OMB) for review. The Order requires agencies to conduct a macro-level cost-benefit analysis for purposes of informing the public and assessing regulatory alternatives. Executive Order 12866, § 1 requires agencies to:

> …assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating. Costs and benefits shall be understood to include both quantifiable measures (to the fullest extent that these can be usefully estimated) and qualitative measures of costs and benefits that are difficult to quantify, but nevertheless essential to consider.

EPA fulfills this mandate by developing RIAs for "significant" rulemakings.[23] As EPA explains, "RIAs contain descriptions of the potential social benefits and social costs of a regulation, including those that cannot be quantified in monetary terms and a determination of the potential net benefits of the rule including an evaluation of the effects that are not monetarily quantified."[24]

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[23] *See, e.g.*, EPA, Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter at ES-1 (Dec. 2012) (PM RIA) ("The RIA fulfills the requirements of Executive Orders 12866 and 13563 and guidelines of the Office of Management and Budget's (OMB) Circular A-4.1").
[24] *See* http://www.epa.gov/ttnecas1/ria.html.

When establishing NAAQS or adopting emission control regulations, EPA estimates the benefits expected from meeting or complying with the rule. This is done by examining the overall benefits of reducing ambient pollution concentrations on worker productivity, reduced hospital visits, medical costs, reduced mortality, and other health-related factors. These benefits are aggregated and compared to the estimated costs of implementing programs to achieve the new standard(s). EPA estimates macro-level benefits associated with significant rules on a national level and does not focus on assessing per-pollutant cost-benefit or externality values.

EPA is required to assess costs and benefits, even when quantification of those costs or benefits is difficult or uncertain. The usefulness of this type of analysis outside of the given regulatory rulemaking it is developed for is therefore extremely limited. When fulfilling the mandate of the Order during recent amendments to the nitrogen dioxide NAAQS, EPA cautioned that:

> As with other NAAQS RIAs, *it should be recognized that all estimates of future costs and benefits are not intended to be forecasts of the actual costs and benefits of implementing revised standards*. . . . Our estimates are intended to provide information on the general magnitude of the costs and benefits of alternative standards, rather than precise predictions of control measures, costs, or benefits.[25]

For a given rule, EPA typically calculates gross costs, gross benefits, and net benefits. This macro-level approach allows EPA to satisfy the Order and related OMB requirements, but does not result in specific analyses focused on assigning benefits or externality values to specific pollutants. EPA therefore generally expresses the benefits of its rules in terms of total net benefits and not on a dollar per ton of pollutant eliminated basis because to do so would imply accuracy where it does not exist.[26] Converting an aggregate number into a uniformly applicable value-per-ton of pollutant reduced is inaccurate and would be an inappropriate use of this data. EPA's analysis contains many points of uncertainty that may be acceptable for macro-level calculations, but that render the analysis methodologically flawed if applied on a local or facility basis.[27] EPA clearly indicates that the results of their cost-benefit analyses

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[25] EPA, Final Regulatory Impact Analysis (RIA) for the NO2 National Ambient Air Quality Standards (NAAQS) at 5-3. (Jan., 2010) (NO_2 RIA) (emphasis added).

[26] In the instances where EPA uses a benefits-per-ton approach, EPA has not developed new benefits estimations, but rather used prior estimations and methodologies for purposes of estimating a specific rule's net benefit.

[27] The NAAQS are air quality standards set by EPA but implemented by the states. As such, specific pollution reduction measures are not required, and therefore EPA is unable to accurately assess the actual pollution reductions that will result from a given NAAQS amendment. As EPA recently explained when revising its particulate matter standards:

> The setting of a NAAQS does not compel specific pollution reductions and as such does not directly result in costs or benefits. For this reason, NAAQS RIAs are merely illustrative. The NAAQS RIAs illustrate the potential costs and benefits of additional steps States could take

are general estimates and are not intended to be presumed as actual costs and benefits. The actual externality impact in dollar per ton reduced will vary greatly depending upon where that ton is emitted – be it in an attainment or non-attainment area – and is also highly dependent upon site-specific data such as meteorology, topography, pollutant source, population exposure, baseline health incidence rates, and other local factors that affect the costs or benefits resulting from a national rule in a particular location or with respect to any particular source. While locally-specific factors are not taken into consideration in EPA's RIAs, the Commission recognized their importance in its environmental externalities proceeding by developing Minnesota-specific values for impacts by sources in various locations: Metropolitan, Urban, Rural, and Within 200 miles of Minnesota.

On another note, EPA's cost benefit analyses are specific to the incremental reductions projected for each particular rulemaking and are not applicable outside of a given rule or on a stand-alone basis. The recent PM NAAQS revisions provide a good example. Although EPA calculated the benefits of PM reductions across the entire country, those benefits depended exclusively on PM reductions occurring in California.[28] As EPA explained, "[f]or the revised annual [PM] standard of 12 μg/m3, *all of the estimated benefits occur in California because this is the only state that needs additional air quality improvement beyond the analytical baseline after accounting for the air quality improvements from recent rules*."[29] Therefore, any cost-benefits estimated from implementation of the PM NAAQS are applicable only to those areas in California and not anywhere else in the country.

In summary, the benefits analyses conducted by EPA in RIAs is focused on generating high level estimates of net benefits to comply with OMB requirements and the Order. There are multiple uncertainties inherent in calculating any environmental benefit. While these uncertainties do not undermine EPA's goal of providing "information on the general magnitude of the costs and benefits" such uncertainties preclude downward extrapolation of high-level net benefits estimates to "precise predictions of control measures, costs, or benefits" (including per-ton benefit or externality values) for a specific plant.[30]

> to attain a revised air quality standard nationwide beyond rules already on the books. We base our illustrative estimates on an array of emission control strategies for different sources. The costs and benefits identified in this RIA will not be realized until specific controls are mandated by SIPs or other Federal regulations. In short, NAAQS RIAs hypothesize, but do not prescribe, the control strategies that States may choose to enact when implementing a revised NAAQS. (PM RIA at ES-18.)

[28] *See* PM RIA at ES-8; 5-67.
[29] PM RIA at 5-89 (emphasis added).
[30] *See* NO_2 RIA at 5-3.

Externalities are those costs incurred by society that are un-priced or not otherwise accounted for. The primary NAAQS are set at a level "requisite to protect the public health" with an adequate margin of safety, and the secondary NAAQS are set at a level "requisite to protect the public welfare."[31] In the recent PM NAAQS RIA, EPA explained that:

> [O]ne of the reasons a regulation such as the NAAQS may be issued is to address existing "externalities." An externality occurs when parties to a transaction do not bear its full consequences. An environmental problem, such as pollution generated from production of a good, which imposes health costs on those who neither produce nor consume it, is a classic case of an externality. In the presence of externalities, a free market does not ensure an efficient allocation of resources. *Setting and implementing primary and secondary air quality standards is one way the government can address an externality and increase air overall public health and welfare.*[32]

The RIAs for the SO_2, NO_2, and Ozone NAAQS each contain explanatory statements on the nature of externalities and various mechanisms people and governments use to address externalities.[33] These statements are nearly identical and conclude that:

> From an economics perspective, *setting an air quality standard is a straightforward case of addressing an externality*, in this case where entities are emitting pollutants, which cause health and environmental problems without compensation for those suffering the problems. Setting a standard with a reasonable margin of safety attempts to place the cost of control on those who emit the pollutants and lessens the impact on those who suffer the health and environmental problems from higher levels of pollution.[34]

Once NAAQS have been attained for a given pollutant, any associated externalities have been eliminated or minimized by imposing control requirements and associated costs on sources. Because NAAQS must be set to protect human health and public welfare without consideration of costs, emissions at levels below the NAAQS should not impose additional externality costs on public health and welfare. EPA's RIA analyses attempt to estimate the costs and benefits associated with a particular rule, and in that sense provide a macro-level picture of that rule's net benefits.

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[31] 42 U.S.C. § 7409.
[32] PM RIA at 1-4 (emphasis added).
[33] *See* NO_2 RIA at 1-3:4; *Final Ozone NAAQS Regulatory Impact Analysis* at 1-2:3, EPA (March 2008) (Ozone RIA); *Final Regulatory Impact Analysis (RIA) for the SO_2 National Ambient Air Quality Standard (NAAQS)* at 1-2:5, EPA (June 2010) (SO_2 RIA).
[34] SO_2 RIA at 1-5 (emphasis added).

V. NATIONAL RESEARCH COUNCIL STUDY

Preceding the submission of this study, Xcel Energy asked the Environmental Intervenors for suggestions on a source for federal externality values. As the discussed above, except for CO_2, there is no proceeding where one set of potential cost ranges have been developed for consistent use in analyses of new air emission control rules. Xcel Energy was referred to a study by the NRC entitled *The Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use*. Xcel Energy was unable to find this study used by EPA as a basis for any recent criteria and hazardous air pollutant benefits estimates for regulations affecting the utility industry.[35] However, we evaluated this study and present scenarios based upon the cost values found in the study. This section explains those scenarios and analyzes the study.

A. Examination of the National Research Council Study and Applicability to Sherco Units 1 and 2

The NRC study was examined to determine the appropriateness of applying its externality costs to Sherco 1 and 2 emission scenarios. NRC describes itself as an independent, objective, and nonpartisan body that conducts studies and reports on a variety of subjects. This study was developed to define and evaluate the health, environment, security, and infrastructure external costs and benefits associated with the production and consumption of energy. Specifically, the study looked at the costs and benefits that are not or may not be fully incorporated into applicable revenue measures related to the production and consumption of energy.

The NRC established a committee to conduct the study and to develop the report. The report was drafted by the committee and reviewed by individuals according to NRC Report Review process procedures. Comments from the reviewers were considered, though not necessarily incorporated. There was no public comment period for review of the final report, meaning that no opportunity for public comment exists on the report generated by the NRC.

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[35] The National Research Council (NRC) study, titled "The Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use" was cited in relation to CO_2 emissions in the RIAs for the Mercury and Air Toxics Standard, the Industrial Boiler MACT, and the proposed New Source Performance Standard for Greenhouse Gases from Electric Generating Units. These RIAs made no mention of the NRC study for criteria pollutant externality impacts. In addition, a review of the PM RIA, Ozone RIA, SO_2 RIA, and NO_2 RIA yielded no reference to the NRC study.

In general, Xcel Energy has the following observations on the NRC report:

- The NRC report notes on page 337 that "The external effects of energy are mostly negative, but the overall benefits of U.S. energy systems to society are enormous. However, the estimation of those benefits, which are mostly reflected in energy prices and markets, was not included in the committee's charge." While it is common practice to focus on the negative cost impacts of energy production, the positive system benefits should also be considered in order to offer an impartial, balanced evaluation of the energy system.

- The NRC study represents a broad cross-section of the power generation sector. As such it presents data on national impacts rather than localized impacts. In addition, it includes data from a broad range of generating plants with varying fuel types, control equipment and emissions profiles. The report does not focus on a specific facility, but instead looks at the entire coal fleet to arrive at its conclusions. While this may have value for developing broad policy approaches, it is not readily transferable to a site-specific analysis such as this study.

- The NRC study argues that an externality remains even when emissions are controlled at the economically optimal level. This is in conflict with the views of other economists that state that no externality exists if emissions are controlled to the economically optimal level. The latter viewpoint is applied by EPA in the RIAs discussed above.

- The data and assumptions used in the study are significantly out of date (*e.g.*, emissions data from 2005 is used in the NRC study). Since 2005, air emissions from Sherco Units 1 and 2 have been reduced through emissions reduction projects at the site. In addition, Xcel Energy has implemented its Metropolitan Emissions Reduction Project, which significantly reduced emissions in Minnesota. It should also be noted that EPA has developed a number of new regulations that require further emissions reductions from the power generation sector, which are summarized in Appendix A. After these new rules and regulations are fully implemented, the 2005 emissions dataset will significantly over-estimate actual emissions and therefore externality costs.

- The NRC study also makes now-obsolete assumptions regarding future generation and fuel use, such as predicting a 20% net increase in coal generation by 2030. The energy picture has changed dramatically since the time this report was written. The discovery of domestic natural gas resources, the impacts of the Great Recession and the change in the environmental regulatory landscape have changed generation outlooks and load growth forecasts. As a result the predictions made in the NRC study are not representative of current industry conditions.

- It should be noted that any attempt to apply NRC-developed externality costs to coal generation would also need to be applied to all generation alternatives being considered (*e.g.*, gas, wind, solar, nuclear).

- Xcel Energy is not aware of any effort to vet the NRC study's values through a robust public comment process.

In summary, the NRC study may provide some perspectives related to developing broad national energy policy, but has limitations that reduce its value for use in a site-specific analysis.

B. Estimation of Sherco Unit 1 and 2-Specific Values based on NRC Study

To incorporate the externality values from the NRC study into this analysis, an effort was made to extract values from the published data that would likely be applicable to Sherco Units 1 and 2. Table 2-11 in the NRC study presents data representing the distribution of pounds of criteria pollutant emissions per megawatt-hour by coal-fired power plants. This data represents criteria pollutant emissions rates for 406 coal-fired plants using 2005 emissions data.[36] In order to present a more up-to-date picture of how Sherco Units 1 and 2 compare to this dataset, we compared the specific emissions data from these units to the tabulated data. We specifically looked at SO_2, NO_x and PM_{10} data as we have a robust dataset for these pollutants for Sherco Units 1 and 2. The tabulated and Sherco data was plotted to determine the corresponding percentiles. The SO_2 plot showed that the Sherco Unit 1 and 2 emission rate equated to a 3rd percentile emission rate compared to the tabulated values while the NO_X and PM_{10} data corresponded to a 10th percentile and 29th percentile, respectively.

[36] We were unable to find Sherco Unit 1 and 2 specific data within the NRC Study.

TABLE 2-11. Distribution of Pounds of Criteria-Pollutant-Forming Emissions per Megawatt-Hour by Coal-Fired Power Plants, 2005

	Mean	Standard Deviation	5th Percentile	25th Percentile	50th Percentile	75th Percentile	95th Percentile
SO2	12	11	1.5	5.4	8.9	16	33
NOx	4.1	2.3	1.3	2.6	3.7	4.9	9.0
PM2.5	0.59	0.58	0.092	0.20	0.35	0.81	1.8
PM10	0.72	0.67	0.12	0.28	0.48	0.94	2.1

ABBREVIATIONS: SO2 = sulfur dioxide = NOx, oxides of nitrogen; PM = particulate matter.

Sherco Units 1 and 2 data: 1.1 lb SO2/MWh (expected value in 2015);
1.6 lb NOx/MWh (expected value in 2015);
0.31 lb PM10/MWh (2012 actual value).

In order to estimate the cost per kilowatt-hour values for Sherco Units 1 and 2, we then consulted Table 2-9 from the NRC study. This table contains data representing the distribution of estimated damages per kilowatt-hour with emissions from 406 coal-fired power plants in 2005 (in 2007 dollars). The Sherco Units 1 and 2 percentile values per pollutant, as determined above, were applied to Table 2-9 and plots were developed. The SO_2 plot showed that the SO_2 emission rate equated to a value of 0.15 cents/kWh while the NO_x and PM_{10} data corresponded to 0.095 cents/kWh and 0.0046 cents/kWh, respectively.

TABLE 2-9. Distribution of Criteria Air Pollutant Damages per Kilowatt-hour with Emissions from 406 Coal-fired Power Plants in 2005 (2007 Cents)

	Mean	Standard Deviation	5th Percentile	25th Percentile	50th Percentile	75th Percentile	95th Percentile
SO2	3.8	4.1	0.24	1.0	2.5	5.2	11.9
NOx	0.34	0.38	0.073	0.16	0.23	0.36	0.91
PM2.5	0.30	0.44	0.019	0.053	0.13	0.38	1.1
PM10	0.017	0.023	0.001	0.004	0.008	0.023	0.060
Total (equally weighted)	4.4	4.4	0.53	1.4	2.9	6.0	13.2
Total (weighted by net generation)	3.2	4.3	0.19	0.71	1.8	4.0	12.0

NOTE: In the first five rows of the table, all plants are weighted equally; that is, the average damage per kWh is 4.4 cents, taking an arithmetic average of the damage per kWh across all 406 plants. In the last row of the table, the damage per kWh is weighted by the electricity generated by each plant to produce a weighted damage per kWh.

ABBREVIATIONS: SO2 = sulfur dioxide = NOx, oxides of nitrogen; PM = particulate matter.

Sherco Units 1 and 2 data: 0.15 cents/kWh for SO_2 (expected value in 2015);
0.095 cents/kWh for NOx (expected value in 2015);
0.0046 cents/kWh for PM_{10} (2012 actual value).

C. Cost Estimate Impacts Using Values Derived From NRC Study

The cost impacts that result from using the NRC values in place of the Minnesota values do not add significant new insight to the analysis already performed. The federal CO_2 values confirm the same result that the other six CO_2 sensitivities already have: that higher CO_2 costs lower the cost effectiveness of continued operation of Sherco Units 1 and 2. Use of the NRC values for SO_2, NO_x, and PM_{10} also reduce the cost effectiveness of continued operations, however because emissions of these pollutants from Sherco Units 1 and 2 are already low and will be reduced even further, the cost impact is much smaller.

To model the cost impact of the NRC Values, the Company used the total annual emissions from the early retirement scenario (#1) and the early SCR scenario (#13) using the sensitivity assumption of no energy available to be purchased from the MISO market ("Markets Off"). In our standard Strategist dispatch simulations energy purchased from MISO has particularly high emission rates that are based on the current rates observed in MISO. In scenario #13, when Sherco Units 1 and 2 are retired the model increases its MISO purchases to partially compensate for the retired units. This would lead to abnormally high emissions of SO_2, NO_x, and PM_{10}.[37] Use of the "Markets Off" sensitivity results in the largest reduction in these pollutants and also the largest externality cost estimates, so is a conservative analysis.

Generally, the damage cost estimates found through use of the NRC values were higher than the externality values specified by the Commission, with the exception of PM_{10}. Table 1 compares the Minnesota values to the NRC values analyzed in this section. Note that Minnesota specifies a range of values to be used based on where generators are located, while the NRC values do not.

Table 1 – Comparison of Values

	Minnesota Externality Values	NRC / RIA Values
SO2	$0/ton	$3,190-$4,303/ton
NOx	$149-$1,442/ton	$756-$1,983/ton
PM10	$1,245-$9,354/ton	$28-$978/ton
CO2	$21.50/ton in 2017 escl@ 2.36%	$37-$57/ton in 2013 escl@ 4.2%

[37] It should be noted that a scenario that results in greater purchases from MISO may result in no overall criteria pollutant emission reductions for these pollutants, and might increase them, calling into question whether any assumed externality costs would actually be addressed.

As discussed in this study, the costs associated with CO_2 plays a large role in estimating the cost effectiveness of scenarios for Sherco Units 1 and 2. Through our Strategist analysis we determined that our base assumption of $21.50/ton CO_2 increased the benefits of retirement by $1.1 billion on a PVRR basis. The federal CO_2 RIA values are higher, start earlier, and escalate faster. As shown in Table 2, the PVRR impact was larger using the federal RIA CO_2 values, up to $3 billion for the $57.00/ton sensitivity. The cost impact from the other pollutants was much smaller. Despite substantially higher dollars per ton based on the NRC values for SO_2, NO_x and PM_{10}, the total cost impact is quite small at $159 million. This is primarily a reflection of the fact that Sherco Units 1 and 2 will have even lower emission rates for SO_2 and PM_{10} upon completion of the sparger tube improvement in their wet ESPs and installation of SCRs assumed in the scenarios lowers the NO_x emission rate.

Table 2 – Impact of CO_2 RIA and NRC Study Values

NPV of SO2, NOx, and PM10 Values ($millions)		
	Early SCRs (scenario 1)	**Early Retirement (scenario 13)**
NPV	$1,179	$1,020
	Net Impact	**($159)**
NPV Federal CO2 Values ($millions)		
	Early SCRs (scenario 1)	**Early Retirement (scenario 13)**
Low	$11,865	$9,929
	Net Impact	**($1,936)**
High	$17,509	$14,692
	Net Impact	**($2,817)**

To calculate these values a spreadsheet model was utilized that took total annual emission estimates from the appropriate Strategist runs and multiplied the NRC Values and federal RIA CO_2 Value by those annual tons. Figures 1 through 4, illustrate the annual tons of emissions that were estimated using Strategist for the scenarios that were compared.

Figure 1: Strategist Annual SO2 Emissions

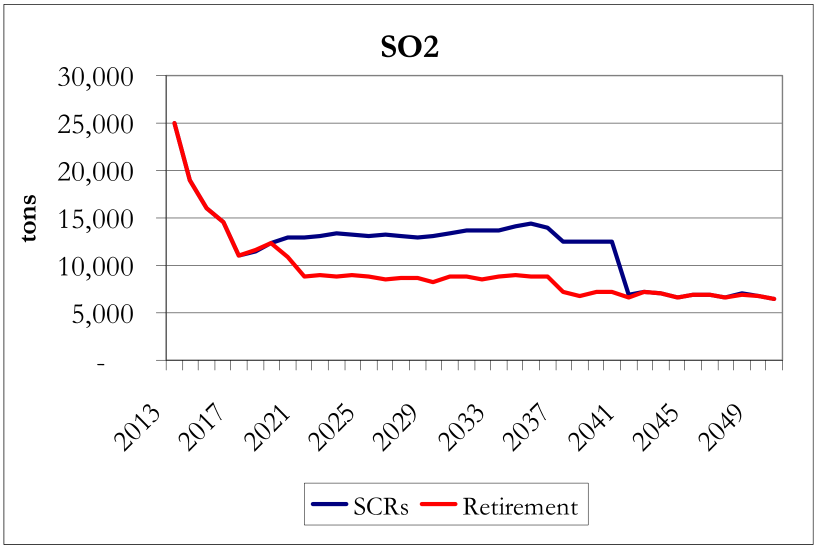


Figure 2: Strategist Annual NOx Emissions

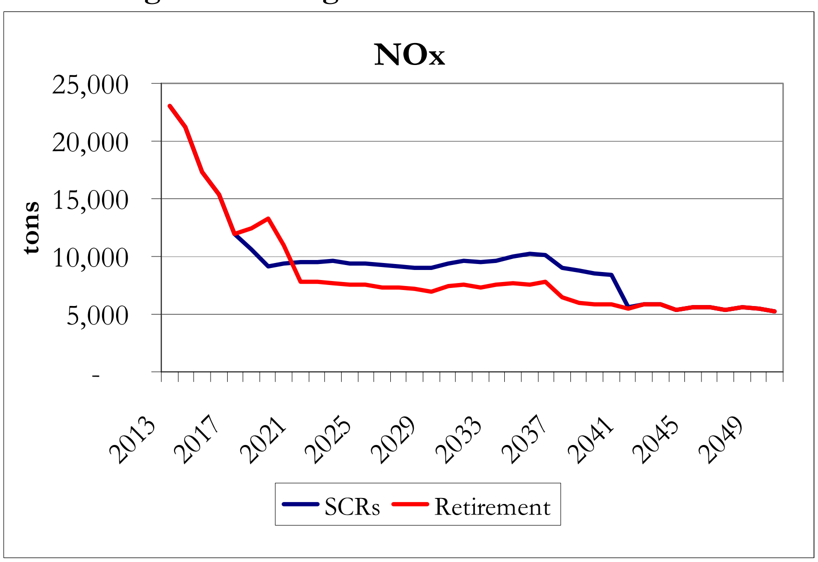


Figure 3: Strategist Annual PM10 Emissions

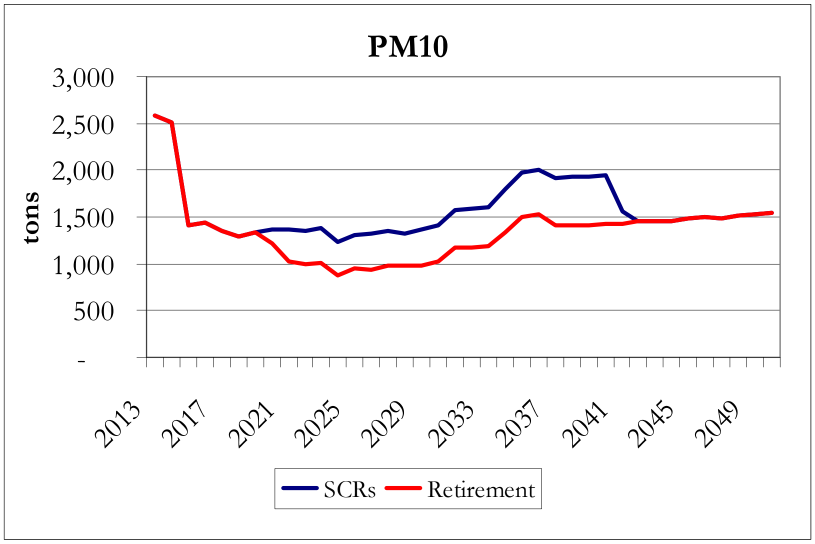
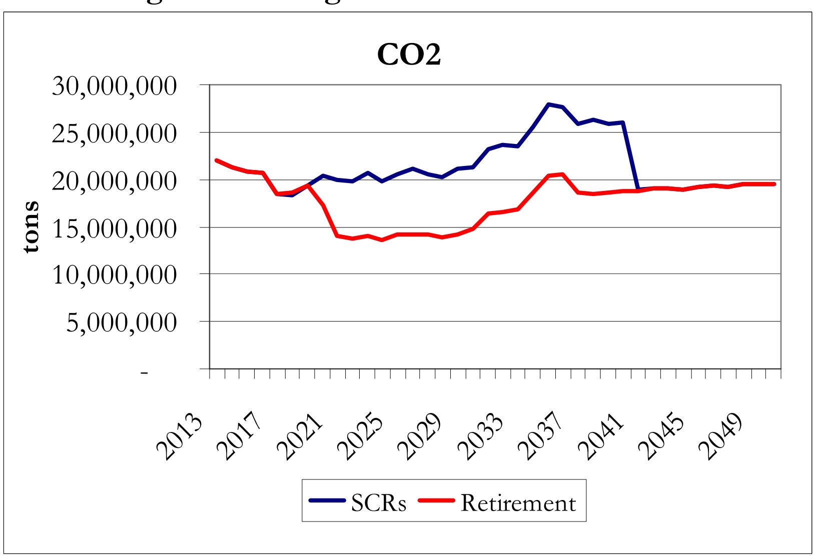


Figure 4: Strategist Annual CO2 Emissions



VI. SUMMARY

Since the establishment of externality values specific to Minnesota by the Commission, the NAAQS have been reviewed and made more stringent, multiple additional emission reduction requirements have been imposed (*see* Appendix A), and emissions from Minnesota power plants and multiple other sources have declined.[38] Xcel Energy believes that the Commission's updated externality values, carbon proxy costs, and the costs of control that have been estimated for Sherco Units 1 and 2 based on anticipated environmental regulatory developments for non-carbon emissions are a more appropriate indicator of any residual externalities than any values that might be extrapolated from EPA's varied RIAs or the NRC study.

Xcel Energy's scenarios, with the exception of the scenario requested by stakeholders and discussed in section V above, include both the cost of Selective Catalytic Reduction (SCR) control technology and the Commission's approved environmental externality costs. Sensitivity analyses also include the carbon regulation proxy costs at the high, midpoint, and low ends of the Commission-approved range. The detailed assessment in Appendix A of the impact of anticipated federal and state environmental regulation on non-carbon emissions from Sherco Units 1 and 2 establishes that the only additional control technology investment that could be made is SCRs.

[38] *Air Quality In Minnesota: 2013 Report to the Legislature* at 3 & 15, Minnesota Pollution Control Agency, January 2013.

Appendix D
Modeling Inputs and Assumptions

Load Forecast 2013-2040

Energy and Demand Forecast (Spring 2013)

	Energy (MWh)	Demand (MW)
2013	44,714	9,223
2014	44,679	9,271
2015	44,854	9,349
2016	45,211	9,437
2017	45,385	9,540
2018	45,675	9,644
2019	46,001	9,748
2020	46,370	9,864
2021	46,701	9,979
2022	47,041	10,102
2023	47,328	10,220
2024	47,600	10,338
2025	47,828	10,449
2026	48,119	10,572
2027	48,466	10,701
2028	48,863	10,837
2029	49,222	10,968
2030	49,571	11,111
2031	49,864	11,254
2032	50,233	11,398
2033	50,606	11,544
2034	50,975	11,703
2035	51,322	11,860
2036	51,702	12,017
2037	52,036	12,173
2038	52,400	12,339
2039	52,769	12,502
2040	53,168	12,671

Average Annual Growth - Forecasted

	Energy (MWh)	Demand (MW)
2013 - 2019	0.47%	0.93%
2020 - 2030	0.68%	1.19%
2030 - 2040	0.71%	1.31%
2013 - 2040	0.64%	1.18%

Coal Price Forecast ($/mmBTU)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
King	$2.18	$2.41	$2.36	$2.39	$2.53	$2.61	$2.67	$2.71	$2.78	$2.86
Black Dog	$1.94	$2.23	$2.23	$2.28	$2.36	$2.43	$2.49	$2.53	$2.59	$2.66
Sherco	$2.24	$2.27	$2.27	$2.27	$2.36	$2.43	$2.49	$2.52	$2.59	$2.66

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
King	$2.93	$3.01	$3.09	$3.17	$3.26	$3.33	$3.41	$3.49	$3.58	$3.66
Black Dog	$2.74	$2.81	$2.88	$2.96	$3.05	$3.12	$3.19	$3.27	$3.35	$3.43
Sherco	$2.73	$2.80	$2.88	$2.95	$3.03	$3.11	$3.18	$3.25	$3.33	$3.41

	2033	2034	2035	2036	2037	2038	2039	2040
King	$3.74	$3.82	$3.90	$3.98	$4.06	$4.14	$4.22	$4.31
Black Dog	$3.50	$3.58	$3.66	$3.73	$3.80	$3.88	$3.96	$4.04
Sherco	$3.48	$3.56	$3.63	$3.71	$3.78	$3.85	$3.93	$4.01

(1) - All-inclusive price forecast - contracted fuel and delivery

(2) - Spring 2013 Forecast

Environmental Externality Values - Metropolitan Fringe - Sherco

	PM10	CO	Pb	NOx
2013	$4,210	$1.95	$2,910	$388
2014	$4,309	$2.00	$2,978	$397
2015	$4,411	$2.05	$3,049	$407
2016	$4,515	$2.09	$3,121	$416
2017	$4,621	$2.14	$3,194	$426
2018	$4,730	$2.19	$3,270	$436
2019	$4,842	$2.25	$3,347	$447
2020	$4,956	$2.30	$3,426	$457
2021	$5,073	$2.35	$3,507	$468
2022	$5,193	$2.41	$3,589	$479
2023	$5,315	$2.46	$3,674	$490
2024	$5,441	$2.52	$3,761	$502
2025	$5,569	$2.58	$3,849	$514
2026	$5,701	$2.64	$3,940	$526
2027	$5,835	$2.71	$4,033	$538
2028	$5,973	$2.77	$4,129	$551
2029	$6,114	$2.84	$4,226	$564
2030	$6,258	$2.90	$4,326	$577
2031	$6,406	$2.97	$4,428	$591
2032	$6,557	$3.04	$4,532	$605
2033	$6,712	$3.11	$4,639	$619
2034	$6,870	$3.19	$4,749	$634
2035	$7,032	$3.26	$4,861	$649
2036	$7,198	$3.34	$4,976	$664
2037	$7,368	$3.42	$5,093	$680
2038	$7,542	$3.50	$5,213	$696
2039	$7,720	$3.58	$5,336	$712
2040	$7,720	$3.58	$5,336	$729

(1) "Notice of Updated Environmental Externality Values"
Dockets CI-93-583 and CI-00-1636, June 13, 3002
(2) Inflation adjusted values, 2011 $/ton, High values
(3) The Sherco site is located in the Metropolitan Fringe
(4) Inflation Rate = 2.36%

Reference Case 2013-2040 Expansion Plan

	Retirement	Combined Cycle	Combustion Turbine	Base Load	Solar	Wind Additions
2013				Monticello EPU 65MW	SolrRwds 1 MW	
2014					SolrRwds 1 MW	
2015	BlackDog 4 -156 MW				SolrRwds 1 MW	Wind 100MW (13MW)
	BlackDog 3 -84 MW					Wind 100MW (13MW)
2016	Coyote 1 -92 MW		Fch Isld 3 57 MW		SolrRwds 1 MW	
2017	Rapidan -3 MW		Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	Key City 4 -15 MW					
	Key City 3 -14 MW					
	Key City 2 -14 MW					
	Granite 4 -13 MW					
	Granite 3 -14 MW					
	Granite 2 -14 MW					
	Granite 1 -13 MW					
2018	Wilmarth 1 -12 MW		Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	Viking -2 MW					
	Red Wing 1 -12 MW					
	HERC -24 MW					
	Flambeau 1 -12 MW					
2019	WSMorrn -6 MW		Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	WindPowr -3 MW					Wind 100MW (13MW)
	Moraine -7 MW					
	KODARAHR -11 MW					
2020					SolrRwds 1 MW	Wind 100MW (13MW)
2021	Fch Isld 4 -57 MW				SolrRwds 1 MW	Wind 100MW (13MW)
	Fch Isld 3 -57 MW					
2022	St.Cloud -8 MW				SolrRwds 1 MW	Wind 100MW (13MW)
2023	St Paul -23 MW		Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	MNDakota -19 MW					Wind 100MW (13MW)
2024	Fch Isld 1 -9 MW				SolrRwds 1 MW	Wind 100MW (13MW)
	Chanaram -11 MW					Wind 100MW (13MW)
	Bayfront 6 -12 MW					
	Bayfront 5 -20 MW					
	Bayfront 4 -11 MW					
2025	Stahl -1 MW	Generic CC 817MW	Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	MNWind -1 MW		Generic CT 226MW			Wind 100MW (13MW)
	MH375500 -488 MW		Generic CT 226MW			
	LkBnton2 -13 MW					
	Invenerg 2 -144 MW					
	Invenerg 1 -151 MW					
2026	Velva -2 MW				SolrRwds 1 MW	Wind 100MW (13MW)
	Tholen -2 MW					
	PineBend -5 MW					
	Norgaard -1 MW					
	Garmcn -1 MW					
	Eastridg -1 MW					
2027	Laurentn 1 -35 MW	Generic CC 817MW			SolrRwds 1 MW	Wind 100MW (13MW)
	Inverhil 6 -45 MW					Wind 100MW (13MW)
	Inverhil 5 -42 MW					
	Inverhil 4 -40 MW					
	Inverhil 3 -41 MW					
	Inverhil 2 -44 MW					

Reference Case 2013-2040 Expansion Plan

	Retirement	Combined Cycle	Combustion Turbine	Base Load	Solar	Wind Additions
2028	WSWstrdg -1 MW		Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	LSCotGrv 1 -226 MW					Wind 100MW (13MW)
	Garmcn -2 MW					
	Ewington -3 MW					
	Cisco -1 MW					
2029	LkBnton1 -14 MW		Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	Jeffers -6 MW					Wind 100MW (13MW)
	FibroMN -46 MW					
2030	Anson 3 -87 MW		Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	Anson 2 -87 MW					
2031	Ruthton -2 MW	Generic CC 817MW	Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	Ridgewnd -3 MW					
	Monti 1 -597 MW					
	GrantCo -3 MW					
	BlueLake 4 -45 MW					
	BlueLake 3 -38 MW					
	BlueLake 2 -39 MW					
	BlueLake 1 -38 MW					
2032	SmllCBED -2 MW		Generic CT 226MW			Wind 100MW (13MW)
	SAF Hydr -4 MW					Wind 100MW (13MW)
	NthShaok -2 MW					
	GoodhuNS -10 MW					
	Danielsn -3 MW					
	CrownHyd -1 MW					
	CommWndN -4 MW					
	BigBlue -5 MW					
	BDog_CC 5 -246 MW					
	Adams -3 MW					
2033	NAEShaok -2 MW		Generic CT 226MW			Wind 100MW (13MW)
	Fenton -27 MW					Wind 100MW (13MW)
						Wind 100MW (13MW)
						Wind 100MW (13MW)
2034	WoodStck -1 MW	Generic CC 817MW				Wind 100MW (13MW)
	P Island 1 -503 MW					
	Lakota -1 MW					
	GrandMed -13 MW					
2035	WINDGEN -13 MW	Generic CC 817MW	Generic CT 226MW			Wind 100MW (13MW)
	WINDGEN -13 MW					Wind 100MW (13MW)
	P Island 2 -510 MW					Wind 100MW (13MW)
	BlueLake 8 -150 MW					
	BlueLake 7 -148 MW					
	Anson 4 -133 MW					
2036	Wheaton 6 -46 MW		Generic CT 226MW			Wind 100MW (13MW)
	Wheaton 5 -37 MW		Generic CT 226MW			Wind 100MW (13MW)
	Wheaton 4 -47 MW					
	Wheaton 3 -46 MW					
	Wheaton 2 -50 MW					
	Wheaton 1 -45 MW					
	Nobles -26 MW					
2037	WINDGEN -13 MW		Generic CT 226MW			Wind 100MW (13MW)
	AS King 1 -477 MW		Generic CT 226MW			
			Generic CT 226MW			
2038	WINDGEN -13 MW	Generic CC 817MW				Wind 100MW (13MW)
	HB_CC 1 -514 MW					
2039	WINDGEN -13 MW	Generic CC 817MW				Wind 100MW (13MW)
	WINDGEN -13 MW					Wind 100MW (13MW)
	RS_CC 1 -416 MW					Wind 100MW (13MW)
2040	WINDGEN -13 MW					Wind 100MW (13MW)

Capacity - Owned Generation Resource

Unit	Dependable Capacity (MW)	Accredited Capacity (MW)
COAL		
King 1	511	477
Black Dog 3	77	84
Black Dog 4	155	156
Sherco 1	681	676
Sherco 2	682	670
Sherco 3 - Xcel	515	496
NUCLEAR		
Monticello 1	652	597
Prairie Island 1	546	503
Prairie Island 2	546	510
BIOMASS		
Bay Front 4	15	11
Bay Front 5	15	20
Bay Front 6	20	12
French Island	17	9
Red Wing	18	12
Wilmarth	18	12
OIL		
Blue Lake 1	52	38
Blue Lake 2	52	39
Blue Lake 3	52	38
Blue Lake 4	59	45
French Island 3	0	0
French Island 4	81	57
Wheaton 5	70	37
Wheaton 6	70	46
Inver Hills D78		
Diesel Generation	6	6
WIND		
Grand Meadow	100	13
Nobles	200	26
HYDRO		
Hydro Generation	268	93

Unit	Dependable Capacity (MW)	Accredited Capacity (MW)
GAS CTs		
Angus Anson 2	120	87
Angus Anson 3	120	87
Angus Anson 4	181	133
Blue Lake 7	180	148
Blue Lake 8	180	150
Flambeau 1	18	12
Granite City 1	16	13
Granite City 2	16	14
Granite City 3	16	14
Granite City 4	16	13
Inver Hills 1	62	42
Inver Hills 2	62	44
Inver Hills 3	62	41
Inver Hills 4	62	40
Inver Hills 5	62	42
Inver Hills 6	62	45
Key City 1	0	0
Key City 2	16	14
Key City 3	16	14
Key City 4	16	15
Wheaton 1	62	45
Wheaton 2	70	50
Wheaton 3	62	46
Wheaton 4	62	47
GAS CCs		
Black Dog 52	276	246
High Bridge	582	514
Riverside	511	416

Energy Conservation and Direct Load Control

	Energy Conservation (MW)	Direct Load Control
2013	98	985
2014	98	995
2015	98	1,004
2016	102	1,013
2017	105	1,024
2018	105	1,035
2019	110	1,045
2020	114	1,056
2021	117	1,066
2022	125	1,077
2023	132	1,079
2024	141	1,075
2025	155	1,070
2026	163	1,066
2027	175	1,062
2028	179	1,058
2029	185	1,054
2030	184	1,050
2031	184	1,046
2032	190	1,042
2033	184	1,038
2034	186	1,034
2035	191	1,030
2036	191	1,026
2037	195	1,023
2038	202	1,019
2039	198	1,015
2040	204	1,012

Other Strategist Inputs

General Inflation Rate – 2.36%
Labor Inflation Rate – 2.51%
Non Labor Inflation Rate – 2.27%
Discount Rate – 7.56%
Composite Tax Rate – 40.75%
CO_2 - $21.50/ton starting in 2017 escalating at general inflation
Externality Costs – Based on midpoint of Commission established values

Appendix E

Present Value Revenue Requirements Results and Annual Details

Strategist - PVRR Total ($000)		01 1 SCR Early - 2 SCR Early	02 1 SCR Late - 2 SCR Late	03 1 Ret Early - 2 SCR Early - Opt	04 1 Ret Early - 2 SCR Early - CC	05 1 Ret Early - 2 SCR Early - CT Wind	06 SCR Early - CT Wind Solar	07 SCR Early - CT Wind Solar DSM	08 1 Ret Late - 2 SCR Late - Opt	09 1 Ret Late - 2 SCR Late - CC	10 1 Ret Late - 2 SCR Late - CT Wind	11 SCR Late - CT Wind Solar	12 SCR Late - CT Wind Solar DSM	13 1 Ret Early - 2 Ret Early - Opt	14 1 Ret Early - 2 Ret Early - CC	15 1 Ret Early - 2 Ret Early - CT Wind	16 1 Ret Early - 2 Ret Early - CT Wind Solar	17 Ret Early - CT Wind Solar DSM	18 1 Ret Late - 2 Ret Late - Opt	19 1 Ret Late - 2 Ret Late - CC	20 1 Ret Late - 2 Ret Late - CT Wind	21 1 Ret Late - 2 Ret Late - CT Wind Solar	22 Ret Late - CT Wind Solar DSM	23 Reference Case
Base		47,977,585	47,868,345	48,053,659	48,053,659	48,483,374	48,817,631	48,545,256	47,924,585	47,924,585	48,249,682	48,484,196	48,267,789	47,940,046	47,940,046	49,375,382	49,740,248	49,434,923	47,870,028	47,870,028	48,787,599	49,045,634	48,811,174	47,586,216
Load - Fall 2011	A	48,744,713	48,635,454	48,828,275	48,828,275	49,274,125	49,601,417	49,331,648	48,696,900	48,696,900	49,037,327	49,267,913	49,050,887	48,716,503	48,716,503	50,142,750	50,509,494	50,204,349	48,641,700	48,641,700	49,562,548	49,824,026	49,587,532	48,353,379
Low Load	B	44,883,659	44,774,467	44,948,497	44,948,497	45,450,617	45,775,495	45,494,833	44,818,693	44,818,693	45,217,719	45,437,608	45,224,463	44,832,048	44,832,048	46,408,491	46,742,540	46,368,768	44,758,914	44,758,914	45,802,616	46,030,321	45,735,473	44,492,593
High Load	C	51,593,786	51,484,502	51,676,053	51,676,053	52,051,555	52,396,584	52,128,585	51,545,774	51,545,774	51,811,721	52,059,748	51,845,817	51,565,600	51,565,600	52,905,316	53,292,599	52,926,562	51,494,208	51,494,208	52,325,310	52,604,649	52,304,110	51,202,391
Low Gas Prices	D	45,123,972	45,015,485	44,859,986	44,859,986	45,736,000	46,159,914	45,835,574	44,821,423	44,821,423	45,540,249	45,843,684	45,591,336	44,458,055	44,458,055	46,767,939	47,180,601	46,835,696	44,561,304	44,561,304	46,203,511	46,493,121	46,231,440	44,736,142
High Gas Prices	E	51,539,038	51,429,761	52,182,102	52,182,102	52,006,493	52,216,111	52,009,610	51,940,154	51,940,154	51,699,350	51,835,001	51,668,039	52,672,540	52,672,540	52,915,738	53,203,984	52,951,844	52,347,724	52,347,724	52,235,344	52,438,027	52,244,110	51,148,055
Low Coal Prices	F	47,369,538	47,260,068	47,588,213	47,588,213	48,030,044	48,363,906	48,088,347	47,434,036	47,434,036	47,769,665	48,003,223	47,784,678	47,626,214	47,626,214	49,093,028	49,447,703	49,139,121	47,500,660	47,500,660	48,443,929	48,693,995	48,457,230	46,978,230
High Coal Prices	G	48,636,836	48,527,687	48,542,704	48,542,704	48,968,377	49,300,722	49,031,450	48,439,882	48,439,882	48,761,709	48,994,961	48,780,575	48,276,176	48,276,176	49,683,725	50,058,540	49,756,613	48,263,096	48,263,096	49,158,118	49,424,030	49,192,056	48,247,175
Wind $30	H	47,977,585	47,868,345	48,053,659	48,053,659	47,599,848	48,038,874	47,915,351	47,924,585	47,924,585	47,532,638	47,871,919	47,762,746	47,940,046	47,940,046	47,243,571	48,167,127	48,010,655	47,870,028	47,870,028	47,257,749	47,916,118	47,788,890	47,586,216
Wind $40	I	47,977,585	47,868,345	48,053,659	48,053,659	47,991,268	48,383,882	48,194,413	47,924,585	47,924,585	47,850,302	48,143,171	47,986,490	47,940,046	47,940,046	48,188,028	48,864,068	48,641,649	47,870,028	47,870,028	47,935,507	48,416,521	48,241,785	47,586,216
Wind $65	J	47,977,585	47,868,345	48,053,659	48,053,659	48,969,971	49,246,529	48,892,172	47,924,585	47,924,585	48,644,589	48,821,403	48,545,938	47,940,046	47,940,046	50,549,453	50,606,629	50,219,323	47,870,028	47,870,028	49,630,165	49,667,716	49,374,197	47,586,216
Solar $100	K	47,977,585	47,868,345	48,053,659	48,053,659	48,483,374	48,560,240	48,329,167	47,924,585	47,924,585	48,249,682	48,284,549	48,097,897	47,940,046	47,940,046	49,375,382	49,262,442	48,998,419	47,870,028	47,870,028	48,787,599	48,702,472	48,497,765	47,586,216
Solar $150	L	47,977,585	47,868,345	48,053,659	48,053,659	48,483,374	49,075,044	48,761,361	47,924,585	47,924,585	48,249,682	48,683,859	48,437,695	47,940,046	47,940,046	49,375,382	50,218,102	49,871,469	47,870,028	47,870,028	48,787,599	49,388,830	49,124,612	47,586,216
Solar $75	M	47,977,585	47,868,345	48,053,659	48,053,659	48,483,374	48,302,825	48,113,060	47,924,585	47,924,585	48,249,682	48,084,884	47,927,988	47,940,046	47,940,046	49,375,382	48,784,587	48,561,872	47,870,028	47,870,028	48,787,599	48,359,275	48,184,326	47,586,216
CO2 $0	N	42,080,068	41,970,958	42,688,477	42,688,477	43,493,224	43,909,884	43,580,706	42,394,259	42,394,259	43,012,574	43,298,383	43,054,502	43,114,714	43,114,714	45,412,533	45,771,200	45,421,218	42,702,947	42,702,947	44,237,112	44,488,761	44,233,302	41,689,590
CO2 $9	O	44,496,328	44,386,983	44,902,084	44,902,084	45,545,866	45,926,934	45,622,266	44,670,031	44,670,031	45,165,725	45,429,311	45,197,372	45,122,198	45,122,198	47,047,555	47,409,191	47,078,034	44,840,178	44,840,178	46,113,454	46,367,705	46,121,025	44,105,359
CO2 $34	P	50,832,905	50,724,756	50,598,391	50,598,391	50,904,117	51,189,305	50,942,112	50,572,849	50,572,849	50,792,141	50,996,259	50,789,758	50,233,724	50,233,724	51,328,468	51,681,217	51,396,196	50,355,256	50,355,256	51,029,313	51,279,454	51,052,593	50,444,735
CO2 $9 2025	Q	43,343,216	43,234,106	43,830,683	43,830,683	44,530,566	44,928,348	44,615,070	43,536,979	43,536,979	44,049,941	44,316,867	44,088,889	44,127,391	44,127,391	46,191,202	46,554,062	46,216,942	43,727,593	43,727,593	45,037,953	45,291,812	45,049,563	42,952,496
CO2 $21.50 2025	R	45,076,096	44,966,986	45,385,287	45,385,287	45,951,754	46,325,476	46,032,320	45,092,232	45,092,232	45,471,152	45,714,020	45,506,164	45,491,157	45,491,157	47,257,605	47,625,820	47,305,426	45,109,187	45,109,187	46,134,993	46,391,808	46,166,713	44,685,165
CO2 $34 2025	S	46,744,641	46,635,531	46,857,612	46,857,612	47,309,650	47,657,944	47,383,372	46,565,585	46,565,585	46,829,071	47,046,505	46,857,233	46,771,580	46,771,580	48,279,187	48,647,459	48,342,812	46,408,408	46,408,408	47,185,907	47,440,693	47,231,789	46,354,590
Sherco Cost +25%	T	48,355,405	48,243,758	48,298,841	48,298,841	48,728,145	49,062,266	48,790,034	48,207,159	48,207,159	48,531,985	48,766,405	48,550,051	48,057,834	48,057,834	49,493,199	49,858,081	49,552,734	48,071,829	48,071,829	48,989,360	49,247,392	49,012,893	47,956,885
SCR Cost +25%	U	48,080,447	47,942,957	48,104,066	48,104,066	48,533,702	48,867,932	48,595,595	47,960,762	47,960,762	48,285,793	48,520,290	48,303,906	47,940,046	47,940,046	49,375,382	49,740,248	49,434,923	47,870,028	47,870,028	48,787,599	49,045,634	48,811,174	47,586,216
CC & CT Costs + 25%	V	48,082,963	47,973,723	48,343,410	48,343,410	48,660,452	48,942,270	48,669,894	48,156,513	48,156,513	48,389,194	48,581,531	48,365,124	48,363,120	48,363,120	49,602,349	49,889,831	49,584,506	48,192,318	48,192,318	48,960,876	49,159,852	48,925,392	47,691,594
Changed State Policy	X	50,755,673	50,646,783	50,671,930	50,846,160	52,095,032	52,506,489	52,114,465	50,492,601	50,761,805	51,832,460	52,108,327	51,811,562	50,638,703	50,638,703	53,926,772	54,140,157	53,712,035	50,406,984	50,651,406	53,174,648	53,289,153	52,966,025	50,366,142
Markets Off	Y	47,982,286	47,873,288	48,059,994	48,059,994	48,498,885	48,826,743	48,556,413	47,930,901	47,930,901	48,257,767	48,487,994	48,273,404	47,949,361	47,949,361	49,409,940	49,763,425	49,459,017	47,878,256	47,878,256	48,809,486	49,057,544	48,823,818	47,591,591
SCR Depreciation 10YR	Z	47,971,452	47,863,788	48,050,650	48,050,650	48,480,364	48,814,622	48,542,246	47,922,349	47,922,349	48,247,446	48,481,959	48,265,553	47,940,046	47,940,046	49,375,382	49,740,248	49,434,923	47,870,028	47,870,028	48,787,599	49,045,634	48,811,174	47,586,216
SCR Depreciation 5YR	AA	47,963,752	47,858,067	48,046,871	48,046,871	48,476,586	48,810,843	48,538,468	47,919,542	47,919,542	48,244,639	48,479,152	48,262,745	47,940,046	47,940,046	49,375,382	49,740,248	49,434,923	47,870,028	47,870,028	48,787,599	49,045,634	48,811,174	47,586,216

Strategist - PVRR Deltas ($000)		01 1 SCR Early - 2 SCR Early	02 1 SCR Late - 2 SCR Late	03 1 Ret Early - 2 SCR Early - Opt	04 1 Ret Early - 2 SCR Early - CC	05 1 Ret Early - 2 SCR Early - CT Wind	06 SCR Early - CT Wind Solar	07 SCR Early - CT Wind Solar DSM	08 1 Ret Late - 2 SCR Late - Opt	09 1 Ret Late - 2 SCR Late - CC	10 1 Ret Late - 2 SCR Late - CT Wind	11 SCR Late - CT Wind Solar	12 SCR Late - CT Wind Solar DSM	13 1 Ret Early - 2 Ret Early - Opt	14 1 Ret Early - 2 Ret Early - CC	15 1 Ret Early - 2 Ret Early - CT Wind	16 1 Ret Early - 2 Ret Early - CT Wind Solar	17 Ret Early - CT Wind Solar DSM	18 1 Ret Late - 2 Ret Late - Opt	19 1 Ret Late - 2 Ret Late - CC	20 1 Ret Late - 2 Ret Late - CT Wind	21 1 Ret Late - 2 Ret Late - CT Wind Solar	22 Ret Late - CT Wind Solar DSM	23 Reference Case
Base		391,369	282,129	467,443	467,443	897,157	1,231,415	959,039	338,369	338,369	663,466	897,979	681,573	353,829	353,829	1,789,166	2,154,032	1,848,706	283,812	283,812	1,201,382	1,459,418	1,224,957	0
Load - Fall 2011	A	391,334	282,075	474,896	474,896	920,746	1,248,038	978,269	343,521	343,521	683,948	914,534	697,508	363,124	363,124	1,789,371	2,156,115	1,850,970	288,321	288,321	1,209,169	1,470,647	1,234,153	0
Low Load	B	391,066	281,874	455,904	455,904	958,024	1,282,902	1,002,240	326,100	326,100	725,126	945,015	731,870	339,455	339,455	1,915,898	2,249,947	1,876,175	266,321	266,321	1,310,023	1,537,728	1,242,880	0
High Load	C	391,395	282,110	473,662	473,662	849,163	1,194,193	926,194	343,383	343,383	609,330	857,356	643,425	363,209	363,209	1,702,925	2,090,208	1,724,171	291,817	291,817	1,122,919	1,402,258	1,101,718	0
Low Gas Prices	D	387,830	279,343	123,843	123,843	999,858	1,423,772	1,099,432	85,281	85,281	804,107	1,107,542	855,194	-278,087	-278,087	2,031,797	2,444,459	2,099,554	-174,839	-174,839	1,467,369	1,756,979	1,495,298	0
High Gas Prices	E	390,983	281,706	1,034,048	1,034,048	858,439	1,068,057	861,555	792,099	792,099	551,295	686,946	519,985	1,524,486	1,524,486	1,767,683	2,055,929	1,803,789	1,199,669	1,199,669	1,087,290	1,289,972	1,096,056	0
Low Coal Prices	F	391,308	281,838	609,983	609,983	1,051,813	1,385,676	1,110,117	455,806	455,806	791,435	1,024,992	806,447	647,984	647,984	2,114,798	2,469,473	2,160,890	522,430	522,430	1,465,699	1,715,765	1,479,000	0
High Coal Prices	G	389,661	280,512	295,529	295,529	721,202	1,053,547	784,275	192,707	192,707	514,534	747,786	533,400	29,001	29,001	1,436,550	1,811,365	1,509,438	15,921	15,921	910,943	1,176,855	944,881	0
Wind $30	H	391,369	282,129	467,443	467,443	13,632	452,657	329,135	338,369	338,369	-53,578	285,703	176,530	353,829	353,829	-342,646	580,910	424,438	283,812	283,812	-328,468	329,902	202,674	0
Wind $40	I	391,369	282,129	467,443	467,443	405,052	797,665	608,196	338,369	338,369	264,086	556,955	400,273	353,829	353,829	601,811	1,277,851	1,055,432	283,812	283,812	349,290	830,304	655,569	0
Wind $65	J	391,369	282,129	467,443	467,443	1,383,755	1,660,313	1,305,956	338,369	338,369	1,058,373	1,235,186	959,721	353,829	353,829	2,963,237	3,020,413	2,633,106	283,812	283,812	2,043,948	2,081,499	1,787,980	0
Solar $100	K	391,369	282,129	467,443	467,443	897,157	974,024	742,951	338,369	338,369	663,466	698,333	511,681	353,829	353,829	1,789,166	1,676,225	1,412,203	283,812	283,812	1,201,382	1,116,256	911,549	0
Solar $150	L	391,369	282,129	467,443	467,443	897,157	1,488,828	1,175,145	338,369	338,369	663,466	1,097,643	851,479	353,829	353,829	1,789,166	2,631,886	2,285,253	283,812	283,812	1,201,382	1,802,613	1,538,395	0
Solar $75	M	391,369	282,129	467,443	467,443	897,157	716,609	526,843	338,369	338,369	663,466	498,667	341,772	353,829	353,829	1,789,166	1,198,371	975,655	283,812	283,812	1,201,382	773,059	598,110	0
CO2 $0	N	390,478	281,368	998,887	998,887	1,803,634	2,220,294	1,891,117	704,669	704,669	1,322,985	1,608,793	1,364,913	1,425,124	1,425,124	3,722,943	4,081,610	3,731,628	1,013,358	1,013,358	2,547,522	2,799,172	2,543,712	0
CO2 $9	O	390,969	281,624	796,726	796,726	1,440,508	1,821,576	1,516,908	564,672	564,672	1,060,367	1,323,952	1,092,013	1,016,840	1,016,840	2,942,196	3,303,832	2,972,676	734,820	734,820	2,008,095	2,262,347	2,015,667	0
CO2 $34	P	388,170	280,021	153,656	153,656	459,382	744,570	497,377	128,114	128,114	347,406	551,524	345,023	-211,011	-211,011	883,733	1,236,482	951,461	-89,479	-89,479	584,578	834,719	607,858	0
CO2 $9 2025	Q	390,720	281,610	878,187	878,187	1,578,070	1,975,852	1,662,574	584,483	584,483	1,097,445	1,364,371	1,136,393	1,174,895	1,174,895	3,238,706	3,601,566	3,264,446	775,097	775,097	2,085,457	2,339,316	2,097,067	0
CO2 $21.50 2025	R	390,931	281,821	700,122	700,122	1,266,589	1,640,311	1,347,155	407,067	407,067	785,987	1,028,855	820,999	805,992	805,992	2,572,440	2,940,656	2,620,261	424,023	424,023	1,449,828	1,706,643	1,481,548	0
CO2 $34 2025	S	390,051	280,941	503,022	503,022	955,060	1,303,354	1,028,782	210,995	210,995	474,481	691,915	502,643	416,990	416,990	1,924,597	2,292,869	1,988,222	53,818	53,818	831,317	1,086,103	877,199	0
Sherco Cost +25%	T	398,520	286,872	341,955	341,955	771,260	1,105,380	833,148	250,273	250,273	575,099	809,520	593,166	100,949	100,949	1,536,313	1,901,195	1,595,848	114,943	114,943	1,032,475	1,290,506	1,056,008	0
SCR Cost +25%	U	494,231	356,740	517,850	517,850	947,485	1,281,716	1,009,379	374,546	374,546	699,577	934,074	717,689	353,829	353,829	1,789,166	2,154,032	1,848,706	283,812	283,812	1,201,382	1,459,418	1,224,957	0
CC & CT Costs + 25%	V	391,369	282,129	651,816	651,816	968,858	1,250,676	978,300	464,919	464,919	697,600	889,937	673,530	671,526	671,526	1,910,755	2,198,237	1,892,912	500,724	500,724	1,269,282	1,468,258	1,233,797	0
Changed State Policy	X	389,530	280,641	305,788	480,017	1,728,889	2,140,347	1,748,323	126,458	395,663	1,466,317	1,742,184	1,445,420	272,561	272,561	3,560,630	3,774,015	3,345,893	40,841	285,263	2,808,506	2,923,010	2,599,882	0
Markets Off	Y	390,695	281,698	468,403	468,403	907,294	1,235,153	964,822	339,310	339,310	666,176	896,404	681,813	357,770	357,770	1,818,350	2,171,835	1,867,426	286,666	286,666	1,217,895	1,465,954	1,232,227	0
SCR Depreciation 10YR	Z	385,235	277,572	464,433	464,433	894,148	1,228,405	956,030	336,133	336,133	661,230	895,743	679,336	353,829	353,829	1,789,166	2,154,032	1,848,706	283,812	283,812	1,201,382	1,459,418	1,224,957	0
SCR Depreciation 5YR	AA	377,535	271,851	460,655	460,655	890,369	1,224,627	952,251	333,325	333,325	658,423	892,936	676,529	353,829	353,829	1,789,166	2,154,032	1,848,706	283,812	283,812	1,201,382	1,459,418	1,224,957	0

Strategist Output - Annual Total System Costs ($000)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
#1 SCR Early - #2 SCR Early	01	1,871,716	1,881,153	1,956,577	2,003,182	2,542,431	2,656,249	2,855,433	3,003,638	3,106,304	3,185,503	3,318,096
#1 SCR Late - #2 SCR Late	02	1,871,716	1,881,153	1,956,577	2,003,182	2,542,431	2,616,219	2,777,610	2,932,756	3,040,870	3,124,414	3,261,022
#1 Ret Early - #2 SCR Early - Opt	03	1,880,854	1,890,741	1,967,086	2,010,668	2,546,928	2,617,145	2,815,195	3,024,634	3,181,048	3,257,873	3,389,620
#1 Ret Early - #2 SCR Early - CC	04	1,880,854	1,890,741	1,967,086	2,010,668	2,546,928	2,617,145	2,815,195	3,024,634	3,181,048	3,257,873	3,389,620
#1 Ret Early - #2 SCR Early - CT Wind	05	1,880,854	1,890,741	1,967,086	2,010,668	2,546,928	2,617,145	2,815,195	3,064,904	3,209,328	3,287,907	3,420,398
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	1,880,854	1,890,741	1,967,086	2,010,668	2,546,928	2,617,145	2,815,195	3,096,670	3,232,361	3,312,310	3,445,894
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	1,880,854	1,890,741	1,967,086	2,019,897	2,553,899	2,622,627	2,837,047	3,106,311	3,186,973	3,266,467	3,399,382
#1 Ret Late - #2 SCR Late - Opt	08	1,875,924	1,885,398	1,961,336	2,007,329	2,546,237	2,619,517	2,779,259	2,935,104	3,045,469	3,126,086	3,258,413
#1 Ret Late - #2 SCR Late - CC	09	1,875,924	1,885,398	1,961,336	2,007,329	2,546,237	2,619,517	2,779,259	2,935,104	3,045,469	3,126,086	3,258,413
#1 Ret Late - #2 SCR Late - CT Wind	10	1,875,924	1,885,398	1,961,336	2,007,329	2,546,237	2,619,517	2,779,259	2,935,104	3,045,469	3,126,086	3,258,413
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	1,875,924	1,885,398	1,961,336	2,007,329	2,546,237	2,619,517	2,779,259	2,935,104	3,045,469	3,126,086	3,258,413
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	1,875,924	1,885,398	1,961,336	2,016,558	2,553,208	2,624,935	2,801,113	2,968,892	3,025,239	3,105,253	3,236,836
#1 Ret Early - #2 Ret Early - Opt	13	1,888,875	1,898,535	1,973,996	2,018,241	2,551,694	2,615,520	2,766,410	2,976,916	3,167,685	3,288,519	3,423,025
#1 Ret Early - #2 Ret Early - CC	14	1,888,875	1,898,535	1,973,996	2,018,241	2,551,694	2,615,520	2,766,410	2,976,916	3,167,685	3,288,519	3,423,025
#1 Ret Early - #2 Ret Early - CT Wind	15	1,888,875	1,898,535	1,973,996	2,018,241	2,551,694	2,615,520	2,766,410	3,017,112	3,388,624	3,489,447	3,622,406
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	1,888,875	1,898,535	1,973,996	2,018,241	2,551,694	2,615,520	2,766,410	3,048,834	3,398,526	3,491,823	3,629,667
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	1,888,875	1,898,535	1,973,996	2,027,470	2,558,665	2,621,002	2,788,316	3,058,478	3,346,654	3,438,976	3,576,024
#1 Ret Late - #2 Ret Late - Opt	18	1,879,726	1,888,990	1,964,704	2,010,813	2,549,308	2,622,462	2,782,215	2,937,620	3,049,700	3,133,482	3,263,046
#1 Ret Late - #2 Ret Late - CC	19	1,879,726	1,888,990	1,964,704	2,010,813	2,549,308	2,622,462	2,782,215	2,937,620	3,049,700	3,133,482	3,263,046
#1 Ret Late - #2 Ret Late - CT Wind	20	1,879,726	1,888,990	1,964,704	2,010,813	2,549,308	2,622,462	2,782,215	2,937,620	3,049,700	3,133,482	3,263,046
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	1,879,726	1,888,990	1,964,704	2,010,813	2,549,308	2,622,462	2,782,215	2,937,620	3,049,700	3,133,482	3,263,046
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	1,879,726	1,888,990	1,964,704	2,020,041	2,556,279	2,627,880	2,804,069	2,971,407	3,029,470	3,112,650	3,241,469
Reference Case	23	1,871,716	1,881,153	1,956,577	2,003,182	2,542,431	2,616,219	2,777,610	2,932,756	3,040,870	3,124,414	3,261,022

Scenario Name	Scenario #	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	3,400,924	3,600,694	3,694,068	3,893,595	4,041,442	4,195,616	4,400,897	4,637,161	4,829,869	5,009,091	5,262,017	5,802,463	6,091,482	6,289,457	6,547,126	6,824,220	6,987,048
#1 SCR Late - #2 SCR Late	02	3,392,434	3,637,808	3,725,098	3,919,743	4,064,332	4,216,016	4,419,791	4,655,544	4,848,071	5,039,940	5,304,867	5,842,712	6,129,130	6,324,505	6,579,573	6,839,310	6,985,520
#1 Ret Early - #2 SCR Early - Opt	03	3,460,392	3,657,172	3,741,175	3,929,977	4,075,031	4,224,492	4,422,316	4,660,373	4,847,301	5,026,858	5,282,914	5,820,106	6,092,957	6,294,113	6,549,301	6,820,712	6,984,149
#1 Ret Early - #2 SCR Early - CC	04	3,460,392	3,657,172	3,741,175	3,929,977	4,075,031	4,224,492	4,422,316	4,660,373	4,847,301	5,026,858	5,282,914	5,820,106	6,092,957	6,294,113	6,549,301	6,820,712	6,984,149
#1 Ret Early - #2 SCR Early - CT Wind	05	3,497,244	3,692,991	3,779,242	3,967,337	4,115,330	4,266,466	4,466,781	4,695,470	4,887,147	5,071,838	5,325,970	5,848,980	6,122,794	6,331,040	6,586,624	6,861,140	7,026,737
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	3,526,002	3,722,500	3,811,133	4,003,617	4,155,287	4,307,906	4,510,232	4,738,405	4,934,528	5,120,413	5,374,281	5,901,202	6,176,697	6,384,775	6,644,142	6,921,778	7,090,274
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	3,477,371	3,674,907	3,762,268	3,953,245	4,103,513	4,255,086	4,471,014	4,705,478	4,900,062	5,113,660	5,390,178	5,851,196	6,125,970	6,335,319	6,593,257	6,869,814	7,037,707
#1 Ret Late - #2 SCR Late - Opt	08	3,335,622	3,663,583	3,806,239	3,990,079	4,131,558	4,278,163	4,473,732	4,710,450	4,896,607	5,075,520	5,344,320	5,879,654	6,150,646	6,349,943	6,603,271	6,872,822	7,018,412
#1 Ret Late - #2 SCR Late - CC	09	3,335,622	3,663,583	3,806,239	3,990,079	4,131,558	4,278,163	4,473,732	4,710,450	4,896,607	5,075,520	5,344,320	5,879,654	6,150,646	6,349,943	6,603,271	6,872,822	7,018,412
#1 Ret Late - #2 SCR Late - CT Wind	10	3,335,622	3,710,398	3,840,818	4,023,768	4,168,220	4,316,652	4,514,957	4,742,574	4,933,633	5,117,729	5,384,638	5,905,277	6,175,618	6,379,830	6,631,363	6,901,809	7,048,414
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	3,335,622	3,743,703	3,863,423	4,051,211	4,199,689	4,349,862	4,550,356	4,777,576	4,973,180	5,158,572	5,425,319	5,950,119	6,222,694	6,427,445	6,683,473	6,957,756	7,107,820
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	3,313,754	3,693,686	3,812,183	3,998,567	4,145,735	4,294,938	4,509,095	4,742,653	4,936,753	5,149,885	5,439,307	5,898,231	6,170,109	6,376,157	6,630,782	6,904,012	7,053,532
#1 Ret Early - #2 Ret Early - Opt	13	3,491,144	3,682,005	3,762,490	3,948,073	4,085,520	4,232,549	4,426,615	4,656,272	4,841,038	5,012,401	5,275,411	5,816,682	6,080,261	6,258,973	6,518,986	6,787,507	6,952,191
#1 Ret Early - #2 Ret Early - CC	14	3,491,144	3,682,005	3,762,490	3,948,073	4,085,520	4,232,549	4,426,615	4,656,272	4,841,038	5,012,401	5,275,411	5,816,682	6,080,261	6,258,973	6,518,986	6,787,507	6,952,191
#1 Ret Early - #2 Ret Early - CT Wind	15	3,707,283	3,882,610	3,973,451	4,161,039	4,312,862	4,466,483	4,657,548	4,847,681	5,044,079	5,228,857	5,460,897	5,957,873	6,227,819	6,411,894	6,677,970	6,960,386	7,127,107
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	3,717,305	3,898,256	3,992,198	4,186,365	4,339,657	4,497,211	4,693,111	4,894,427	5,094,691	5,285,686	5,528,132	6,039,076	6,315,064	6,502,133	6,774,325	7,058,267	7,233,055
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	3,663,766	3,845,490	3,938,110	4,131,712	4,282,412	4,439,257	4,650,980	4,855,171	5,057,253	5,273,627	5,539,994	5,985,562	6,259,654	6,447,227	6,717,447	7,000,141	7,173,728
#1 Ret Late - #2 Ret Late - Opt	18	3,336,681	3,608,220	3,798,481	4,031,227	4,165,477	4,309,738	4,501,524	4,729,359	4,912,734	5,083,022	5,345,066	5,885,344	6,148,061	6,325,757	6,585,042	6,852,541	7,015,610
#1 Ret Late - #2 Ret Late - CC	19	3,336,681	3,608,220	3,798,481	4,031,227	4,165,477	4,309,738	4,501,524	4,729,359	4,912,734	5,083,022	5,345,066	5,885,344	6,148,061	6,325,757	6,585,042	6,852,541	7,015,610
#1 Ret Late - #2 Ret Late - CT Wind	20	3,336,681	3,656,007	4,034,394	4,242,689	4,391,047	4,541,877	4,730,825	4,919,401	5,114,601	5,298,373	5,529,484	6,024,991	6,292,118	6,472,307	6,734,218	7,012,439	7,175,408
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	3,336,681	3,690,083	4,040,710	4,244,309	4,395,169	4,550,760	4,745,162	4,945,369	5,144,773	5,335,046	5,576,824	6,086,709	6,360,711	6,545,137	6,814,543	7,095,680	7,267,954
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	3,314,813	3,639,627	3,984,389	4,187,384	4,335,745	4,490,701	4,700,989	4,904,118	5,105,374	5,321,052	5,586,777	6,031,311	6,303,445	6,488,399	6,755,860	7,035,774	7,206,906
Reference Case	23	3,346,323	3,548,120	3,643,389	3,844,204	3,993,852	4,150,076	4,356,332	4,594,430	4,789,146	4,982,148	5,249,060	5,789,389	6,076,468	6,273,413	6,530,698	6,803,499	6,965,084

Strategist Output - Annual Capital Expenditures ($000)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
#1 SCR Early - #2 SCR Early	01	49,352	33,286	64,608	181,149	327,171	309,819	145,937	33,195	83,341	196,663	328,646
#1 SCR Late - #2 SCR Late	02	49,352	33,286	61,984	137,556	170,838	188,175	87,611	30,840	80,112	242,877	505,937
#1 Ret Early - #2 SCR Early - Opt	03	49,352	33,129	58,418	144,645	266,957	431,000	748,709	173,010	62,050	191,057	310,515
#1 Ret Early - #2 SCR Early - CC	04	49,352	33,129	58,418	144,645	266,957	431,000	748,709	173,010	62,050	191,057	310,515
#1 Ret Early - #2 SCR Early - CT Wind	05	49,352	33,129	58,418	144,645	217,972	333,168	553,441	430,272	62,782	191,806	311,281
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	49,352	33,129	58,418	144,645	217,972	305,105	438,540	381,267	61,168	190,154	309,591
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	49,352	33,129	58,418	144,645	217,972	305,105	438,540	322,398	61,168	190,154	309,591
#1 Ret Late - #2 SCR Late - Opt	08	49,352	33,158	61,773	137,345	170,594	182,353	81,597	30,461	76,943	256,439	598,665
#1 Ret Late - #2 SCR Late - CC	09	49,352	33,158	61,773	137,345	170,594	182,353	81,597	30,461	76,943	256,439	598,665
#1 Ret Late - #2 SCR Late - CT Wind	10	49,352	33,158	61,773	137,345	170,594	182,353	81,597	30,461	76,943	201,395	488,731
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	49,352	33,158	61,773	137,345	170,594	182,353	81,597	30,461	76,943	201,395	457,197
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	49,352	33,158	61,773	137,345	170,594	182,353	81,597	30,461	76,943	201,395	457,197
#1 Ret Early - #2 Ret Early - Opt	13	49,352	32,972	55,495	129,332	203,319	375,940	819,856	651,472	158,795	157,102	309,192
#1 Ret Early - #2 Ret Early - CC	14	49,352	32,972	55,495	129,332	203,319	375,940	819,856	651,472	158,795	157,102	309,192
#1 Ret Early - #2 Ret Early - CT Wind	15	49,352	32,972	55,495	129,332	154,334	239,205	512,401	612,437	719,179	156,947	309,034
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	49,352	32,972	55,495	129,332	154,334	211,142	373,950	467,012	495,669	153,644	305,652
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	49,352	32,972	55,495	129,332	154,334	211,142	373,950	408,143	495,669	153,644	305,652
#1 Ret Late - #2 Ret Late - Opt	18	49,352	33,031	61,561	137,135	170,350	176,530	75,583	30,081	76,052	237,939	574,838
#1 Ret Late - #2 Ret Late - CC	19	49,352	33,031	61,561	137,135	170,350	176,530	75,583	30,081	76,052	237,939	574,838
#1 Ret Late - #2 Ret Late - CT Wind	20	49,352	33,031	61,561	137,135	170,350	176,530	75,583	30,081	76,052	182,895	421,188
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	49,352	33,031	61,561	137,135	170,350	176,530	75,583	30,081	76,052	182,895	389,654
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	49,352	33,031	61,561	137,135	170,350	176,530	75,583	30,081	76,052	182,895	389,654
Reference Case	23	49,352	33,286	61,984	137,556	170,838	188,175	87,611	30,840	77,094	192,735	326,120

Scenario Name	Scenario #	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	961,999	513,793	658,812	369,688	310,389	457,235	914,026	499,760	527,787	1,073,215	1,137,123	747,496	968,867	1,276,510	1,159,457	872,975	1,916,059
#1 SCR Late - #2 SCR Late	02	1,095,216	576,669	658,812	369,688	310,389	457,235	914,026	499,760	527,787	1,073,215	1,137,123	747,496	968,867	1,276,510	1,159,457	872,975	1,916,059
#1 Ret Early - #2 SCR Early - Opt	03	926,459	498,608	621,560	326,300	308,816	436,358	880,340	495,527	510,072	1,042,331	1,134,738	729,244	926,335	1,278,896	1,078,370	542,306	917,298
#1 Ret Early - #2 SCR Early - CC	04	926,459	498,608	621,560	326,300	308,816	436,358	880,340	495,527	510,072	1,042,331	1,134,738	729,244	926,335	1,278,896	1,078,370	542,306	917,298
#1 Ret Early - #2 SCR Early - CT Wind	05	927,243	499,411	622,382	327,141	309,677	437,240	881,242	496,451	511,018	1,043,299	1,135,728	730,258	927,373	1,279,958	1,017,428	364,543	446,014
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	925,512	497,640	620,569	325,285	307,778	435,295	879,252	494,413	508,932	1,041,164	1,133,543	728,021	925,083	1,277,614	1,015,029	324,540	289,765
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	925,512	497,640	620,569	325,285	307,778	435,295	879,252	494,413	508,932	1,041,164	1,133,543	728,021	925,083	1,277,614	1,015,029	324,540	289,765
#1 Ret Late - #2 SCR Late - Opt	08	1,685,915	734,074	621,560	326,300	308,816	436,358	880,340	495,527	510,072	1,042,331	1,134,738	729,244	926,335	1,278,896	1,078,370	542,306	917,298
#1 Ret Late - #2 SCR Late - CC	09	1,685,915	734,074	621,560	326,300	308,816	436,358	880,340	495,527	510,072	1,042,331	1,134,738	729,244	926,335	1,278,896	1,078,370	542,306	917,298
#1 Ret Late - #2 SCR Late - CT Wind	10	1,466,492	1,023,160	622,382	327,141	309,677	437,240	881,242	496,451	511,018	1,043,299	1,135,728	730,258	927,373	1,279,958	1,017,428	364,543	446,014
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	1,337,377	968,093	620,569	325,285	307,778	435,295	879,252	494,413	508,932	1,041,164	1,133,543	728,021	925,083	1,277,614	1,015,029	324,540	289,765
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	1,337,377	901,942	620,569	325,285	307,778	435,295	879,252	494,413	508,932	1,041,164	1,133,543	728,021	925,083	1,277,614	1,015,029	324,540	289,765
#1 Ret Early - #2 Ret Early - Opt	13	915,006	472,169	616,889	313,050	275,446	434,740	858,748	459,577	499,857	1,023,062	1,104,269	727,843	905,702	1,228,042	1,018,782	287,166	143,805
#1 Ret Early - #2 Ret Early - CC	14	915,006	472,169	616,889	313,050	275,446	434,740	858,748	459,577	499,857	1,023,062	1,104,269	727,843	905,702	1,228,042	1,018,782	287,166	143,805
#1 Ret Early - #2 Ret Early - CT Wind	15	914,844	472,004	616,720	312,876	275,268	434,559	858,563	459,387	499,662	1,022,863	1,104,065	727,634	905,488	1,227,824	1,018,558	286,937	143,570
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	911,383	468,461	613,093	309,164	271,468	430,669	854,581	455,312	495,491	1,018,593	1,099,695	723,160	900,909	1,223,136	1,013,760	282,025	138,543
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	911,383	468,461	613,093	309,164	271,468	430,669	854,581	455,312	495,491	1,018,593	1,099,695	723,160	900,909	1,223,136	1,013,760	282,025	138,543
#1 Ret Late - #2 Ret Late - Opt	18	1,779,900	1,189,892	752,925	313,050	275,446	434,740	858,748	459,577	499,857	1,023,062	1,104,269	727,843	905,702	1,228,042	1,018,782	287,166	143,805
#1 Ret Late - #2 Ret Late - CC	19	1,779,900	1,189,892	752,925	313,050	275,446	434,740	858,748	459,577	499,857	1,023,062	1,104,269	727,843	905,702	1,228,042	1,018,782	287,166	143,805
#1 Ret Late - #2 Ret Late - CT Wind	20	1,434,412	1,146,029	1,382,631	312,876	275,268	434,559	858,563	459,387	499,662	1,022,863	1,104,065	727,634	905,488	1,227,824	1,018,558	286,937	143,570
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	1,278,835	982,614	1,131,472	309,164	271,468	430,669	854,581	455,312	495,491	1,018,593	1,099,695	723,160	900,909	1,223,136	1,013,760	282,025	138,543
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	1,278,835	916,463	1,131,472	309,164	271,468	430,669	854,581	455,312	495,491	1,018,593	1,099,695	723,160	900,909	1,223,136	1,013,760	282,025	138,543
Reference Case	23	955,299	509,580	656,104	362,502	305,871	454,330	906,319	494,915	524,672	1,064,949	1,131,926	744,155	960,002	1,270,937	1,155,874	863,468	1,916,059

Appendix E
Present Value Revenue Requirements Results and Annual Details

Strategist Output - Annual Total Natural Gas Costs ($000)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	76,803	59,935	87,491	112,498	261,552	281,127	299,540	250,096	256,617	247,590	253,184	256,618	363,951	369,995	404,400	418,353	449,832	515,292	701,907	711,769	784,968	1,026,406	1,251,684	1,315,941	1,568,851	1,615,853	1,621,894	1,681,054
#1 SCR Late - #2 SCR Late	02	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	254,769	363,951	369,995	404,400	418,353	449,832	515,292	701,907	711,769	784,968	1,026,406	1,251,684	1,315,941	1,568,851	1,615,853	1,621,894	1,681,054
#1 Ret Early - #2 SCR Early - Opt	03	76,803	59,935	87,491	112,498	261,552	274,497	295,498	395,671	403,226	410,451	414,609	401,775	543,902	552,523	571,811	616,935	654,039	716,168	947,682	964,643	1,009,513	1,311,124	1,552,981	1,586,857	1,902,273	1,942,980	1,961,540	2,018,756
#1 Ret Early - #2 SCR Early - CC	04	76,803	59,935	87,491	112,498	261,552	274,497	295,498	395,671	403,226	410,451	414,609	401,775	543,902	552,523	571,811	616,935	654,039	716,168	947,682	964,643	1,009,513	1,311,124	1,552,981	1,586,857	1,902,273	1,942,980	1,961,540	2,018,756
#1 Ret Early - #2 SCR Early - CT Wind	05	76,803	59,935	87,491	112,498	261,552	274,497	295,498	316,375	315,871	323,092	328,121	321,060	450,443	463,921	486,746	534,017	563,776	619,318	824,865	848,896	885,844	1,160,270	1,386,758	1,455,551	1,714,371	1,758,053	1,770,271	1,845,206
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	76,803	59,935	87,491	112,498	261,552	274,497	295,498	292,666	290,441	297,758	302,355	295,703	420,835	432,417	453,220	495,953	529,369	578,479	787,890	806,569	846,127	1,118,451	1,345,068	1,401,949	1,672,446	1,710,293	1,724,509	1,797,003
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	76,803	59,935	87,491	111,788	260,382	271,691	290,544	303,769	302,115	309,104	314,693	305,595	435,132	447,851	467,832	511,916	545,576	594,746	812,314	826,529	863,642	1,137,123	1,369,450	1,426,230	1,696,267	1,736,732	1,753,575	1,828,850
#1 Ret Late - #2 SCR Late - Opt	08	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	529,200	552,523	571,811	616,935	654,039	716,168	947,682	964,643	1,009,513	1,311,124	1,552,981	1,586,857	1,902,273	1,942,980	1,961,540	2,018,756
#1 Ret Late - #2 SCR Late - CC	09	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	529,200	552,523	571,811	616,935	654,039	716,168	947,682	964,643	1,009,513	1,311,124	1,552,981	1,586,857	1,902,273	1,942,980	1,961,540	2,018,756
#1 Ret Late - #2 SCR Late - CT Wind	10	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	449,584	463,921	486,746	534,017	563,776	619,318	824,865	848,896	885,844	1,160,270	1,386,758	1,455,551	1,714,371	1,758,053	1,770,271	1,845,206
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	420,064	432,417	453,220	495,953	529,369	578,479	787,890	806,569	846,127	1,118,452	1,345,068	1,401,949	1,672,446	1,710,293	1,724,509	1,797,003
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	76,803	59,935	87,491	111,788	260,382	277,192	288,316	239,925	246,707	240,350	245,434	233,660	434,361	447,851	467,832	511,916	545,576	594,746	812,314	826,529	863,642	1,137,123	1,369,450	1,426,230	1,696,267	1,736,732	1,753,575	1,828,849
#1 Ret Early - #2 Ret Early - Opt	13	76,803	59,935	87,491	112,498	261,552	274,497	282,454	392,370	553,206	562,196	593,257	587,021	718,456	755,275	777,454	807,666	879,232	946,576	1,172,318	1,224,357	1,267,863	1,563,386	1,867,179	1,901,388	2,191,246	2,283,511	2,294,064	2,377,900
#1 Ret Early - #2 Ret Early - CC	14	76,803	59,935	87,491	112,498	261,552	274,497	282,454	392,370	553,206	562,196	593,257	587,021	718,456	755,275	777,454	807,666	879,232	946,576	1,172,318	1,224,357	1,267,863	1,563,386	1,867,179	1,901,388	2,191,246	2,283,511	2,294,064	2,377,900
#1 Ret Early - #2 Ret Early - CT Wind	15	76,803	59,935	87,491	112,498	261,552	274,497	282,454	314,381	278,500	286,564	308,765	308,987	406,726	437,659	463,640	498,456	546,498	594,295	763,778	810,376	853,861	1,087,446	1,331,481	1,380,607	1,604,738	1,667,017	1,683,381	1,747,457
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	76,803	59,935	87,491	112,498	261,552	274,497	282,454	290,623	266,957	272,937	294,031	294,644	393,104	422,833	448,098	481,167	531,855	582,265	756,562	799,988	842,938	1,074,908	1,320,719	1,379,758	1,605,103	1,677,697	1,683,542	1,756,596
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	76,803	59,935	87,491	111,788	260,382	271,691	277,348	301,727	275,321	280,876	302,167	302,249	404,620	433,744	458,567	492,400	543,959	594,663	771,976	815,299	856,942	1,090,577	1,343,510	1,402,864	1,633,992	1,702,041	1,710,847	1,785,409
#1 Ret Late - #2 Ret Late - Opt	18	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	505,957	759,089	777,454	807,666	879,232	946,576	1,172,318	1,224,357	1,267,863	1,563,454	1,864,980	1,900,626	2,191,987	2,285,371	2,294,548	2,377,648
#1 Ret Late - #2 Ret Late - CC	19	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	505,957	759,089	777,454	807,666	879,232	946,576	1,172,318	1,224,357	1,267,863	1,563,454	1,864,980	1,900,626	2,191,987	2,285,371	2,294,548	2,377,648
#1 Ret Late - #2 Ret Late - CT Wind	20	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	432,734	439,651	463,640	498,456	546,498	594,295	763,778	810,376	853,861	1,087,446	1,331,481	1,380,607	1,604,738	1,667,017	1,683,381	1,747,457
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	401,347	424,497	448,098	481,167	531,855	582,265	756,562	799,988	842,938	1,074,908	1,320,719	1,379,758	1,605,103	1,677,697	1,683,542	1,756,596
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	76,803	59,935	87,491	111,788	260,382	277,192	288,316	239,925	246,707	240,350	245,434	233,660	414,744	436,269	458,567	492,400	543,959	594,663	771,976	815,299	856,942	1,090,577	1,343,510	1,402,864	1,633,992	1,702,041	1,710,847	1,785,409
Reference Case	23	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	254,816	362,746	369,308	402,604	416,669	449,198	513,949	700,165	708,780	782,759	1,024,583	1,249,759	1,313,275	1,566,130	1,612,782	1,620,696	1,679,893

Strategist Output - Annual Total Natural Gas Consumption (000mmBtu)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	19,374	14,245	20,153	25,103	55,249	55,552	55,373	43,294	42,523	39,504	37,795	37,174	50,758	50,292	53,782	54,406	56,878	63,319	84,673	84,434	90,703	116,050	138,294	142,753	166,942	168,946	166,441	169,427
#1 SCR Late - #2 SCR Late	02	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	36,902	50,758	50,292	53,782	54,406	56,878	63,319	84,673	84,434	90,703	116,050	138,294	142,753	166,942	168,946	166,441	169,427
#1 Ret Early - #2 SCR Early - Opt	03	19,374	14,245	20,153	25,103	55,249	54,232	54,625	68,314	66,621	65,320	61,785	58,041	75,870	75,096	75,938	80,082	82,577	87,906	114,374	114,292	116,687	148,252	171,648	172,078	202,410	203,125	201,274	203,499
#1 Ret Early - #2 SCR Early - CC	04	19,374	14,245	20,153	25,103	55,249	54,232	54,625	68,314	66,621	65,320	61,785	58,041	75,870	75,096	75,938	80,082	82,577	87,906	114,374	114,292	116,687	148,252	171,648	172,078	202,410	203,125	201,274	203,499
#1 Ret Early - #2 SCR Early - CT Wind	05	19,374	14,245	20,153	25,103	55,249	54,232	54,625	54,729	52,224	51,454	48,952	46,431	62,920	63,062	64,682	69,335	71,259	76,020	99,609	100,544	102,602	131,172	153,329	157,901	182,552	183,928	181,767	186,034
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	19,374	14,245	20,153	25,103	55,249	54,232	54,625	50,619	47,993	47,422	45,098	42,755	58,746	58,772	60,215	64,389	66,865	70,976	95,102	95,457	97,901	126,422	148,691	152,135	177,997	178,891	177,056	181,158
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	19,374	14,245	20,153	24,947	55,005	53,684	53,721	52,525	49,927	49,217	46,936	44,176	60,736	60,820	62,150	66,453	68,908	72,966	97,962	97,957	99,928	128,559	151,369	154,743	180,541	181,662	180,019	184,360
#1 Ret Late - #2 SCR Late - Opt	08	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	73,789	75,096	75,938	80,082	82,577	87,906	114,374	114,292	116,687	148,252	171,648	172,078	202,410	203,125	201,274	203,499
#1 Ret Late - #2 SCR Late - CC	09	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	73,789	75,096	75,938	80,082	82,577	87,906	114,374	114,292	116,687	148,252	171,648	172,078	202,410	203,125	201,274	203,499
#1 Ret Late - #2 SCR Late - CT Wind	10	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	62,799	63,062	64,682	69,335	71,259	76,020	99,609	100,544	102,602	131,172	153,329	157,901	182,552	183,928	181,767	186,034
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	58,639	58,772	60,215	64,389	66,865	70,976	95,102	95,457	97,901	126,422	148,691	152,135	177,997	178,891	177,056	181,158
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	19,374	14,245	20,153	24,947	55,005	54,790	53,316	41,531	40,904	38,358	36,650	33,850	60,629	60,820	62,150	66,453	68,908	72,966	97,962	97,957	99,928	128,559	151,369	154,743	180,541	181,662	180,019	184,360
#1 Ret Early - #2 Ret Early - Opt	13	19,374	14,245	20,153	25,103	55,249	54,232	52,198	67,737	91,288	89,274	88,329	84,659	100,189	102,545	103,077	104,694	110,905	116,169	141,413	144,920	146,641	176,721	206,331	206,324	233,264	238,724	235,403	239,694
#1 Ret Early - #2 Ret Early - CC	14	19,374	14,245	20,153	25,103	55,249	54,232	52,198	67,737	91,288	89,274	88,329	84,659	100,189	102,545	103,077	104,694	110,905	116,169	141,413	144,920	146,641	176,721	206,331	206,324	233,264	238,724	235,403	239,694
#1 Ret Early - #2 Ret Early - CT Wind	15	19,374	14,245	20,153	25,103	55,249	54,232	52,198	54,384	46,125	45,643	46,121	44,729	56,876	59,501	61,618	64,793	68,924	73,013	92,248	96,007	98,946	123,120	147,284	150,005	171,028	174,422	172,954	176,351
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	19,374	14,245	20,153	25,103	55,249	54,232	52,198	50,265	44,130	43,406	43,849	42,583	54,919	57,476	59,490	62,459	67,019	71,417	91,260	94,699	97,516	121,609	146,019	149,801	170,960	175,443	172,902	177,093
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	19,374	14,245	20,153	24,947	55,005	53,684	51,267	52,171	45,507	44,666	45,059	43,680	56,498	58,958	60,874	63,958	68,544	72,929	93,136	96,537	99,159	123,297	148,534	152,298	174,030	178,012	175,695	180,017
#1 Ret Late - #2 Ret Late - Opt	18	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	70,635	102,848	103,077	104,694	110,905	116,169	141,413	144,920	146,641	176,730	206,088	206,246	233,346	238,920	235,464	239,671
#1 Ret Late - #2 Ret Late - CC	19	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	70,635	102,848	103,077	104,694	110,905	116,169	141,413	144,920	146,641	176,730	206,088	206,246	233,346	238,920	235,464	239,671
#1 Ret Late - #2 Ret Late - CT Wind	20	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	60,457	59,819	61,618	64,793	68,924	73,013	92,248	96,007	98,946	123,120	147,284	150,005	171,028	174,422	172,954	176,351
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	56,047	57,623	59,490	62,459	67,019	71,417	91,260	94,699	97,516	121,609	146,019	149,801	170,960	175,443	172,902	177,093
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	19,374	14,245	20,153	24,947	55,005	54,790	53,316	41,531	40,904	38,358	36,650	33,850	57,906	59,323	60,874	63,958	68,544	72,929	93,136	96,537	99,159	123,297	148,534	152,298	174,030	178,012	175,695	180,017
Reference Case	23	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	36,908	50,588	50,197	53,541	54,184	56,795	63,149	84,460	84,074	90,443	115,841	138,077	142,460	166,646	168,618	166,317	169,309

Appendix E

Present Value Revenue Requirements Results and Annual Details

Strategist Output - Annual Total Coal Costs ($000)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
#1 SCR Early - #2 SCR Early	01	357,912	360,682	348,232	357,162	289,129	314,759	347,672	384,654	392,892	397,801	430,837	434,749
#1 SCR Late - #2 SCR Late	02	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	436,098
#1 Ret Early - #2 SCR Early - Opt	03	357,912	360,682	348,232	357,162	289,129	322,740	350,357	272,199	289,705	278,599	310,809	329,697
#1 Ret Early - #2 SCR Early - CC	04	357,912	360,682	348,232	357,162	289,129	322,740	350,357	272,199	289,705	278,599	310,809	329,697
#1 Ret Early - #2 SCR Early - CT Wind	05	357,912	360,682	348,232	357,162	289,129	322,740	350,357	266,154	284,674	272,654	302,134	318,209
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	357,912	360,682	348,232	357,162	289,129	322,740	350,357	263,134	281,385	269,614	299,113	314,703
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	357,912	360,682	348,232	356,933	288,542	321,620	348,903	265,670	284,209	272,477	302,484	318,253
#1 Ret Late - #2 SCR Late - Opt	08	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231
#1 Ret Late - #2 SCR Late - CC	09	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231
#1 Ret Late - #2 SCR Late - CT Wind	10	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	357,912	360,682	348,232	356,933	288,542	314,666	350,424	386,068	393,311	396,994	429,947	446,288
#1 Ret Early - #2 Ret Early - Opt	13	357,912	360,682	348,232	357,162	289,129	322,740	360,583	274,509	178,856	172,988	181,743	197,645
#1 Ret Early - #2 Ret Early - CC	14	357,912	360,682	348,232	357,162	289,129	322,740	360,583	274,509	178,856	172,988	181,743	197,645
#1 Ret Early - #2 Ret Early - CT Wind	15	357,912	360,682	348,232	357,162	289,129	322,740	360,583	267,691	155,992	150,420	156,954	168,736
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	357,912	360,682	348,232	357,162	289,129	322,740	360,583	264,773	162,257	156,455	163,600	175,815
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	357,912	360,682	348,232	356,933	288,542	321,620	359,008	267,327	164,424	158,644	165,811	178,795
#1 Ret Late - #2 Ret Late - Opt	18	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231
#1 Ret Late - #2 Ret Late - CC	19	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231
#1 Ret Late - #2 Ret Late - CT Wind	20	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	357,912	360,682	348,232	356,933	288,542	314,666	350,424	386,068	393,311	396,994	429,947	446,288
Reference Case	23	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	436,144

Scenario Name	Scenario #	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	443,669	471,621	479,024	477,275	510,422	525,201	539,107	571,312	575,391	589,962	636,718	641,111	521,502	539,872	566,665	577,858
#1 SCR Late - #2 SCR Late	02	443,669	471,621	479,024	477,275	510,422	525,201	539,107	571,312	575,391	589,962	636,718	641,111	521,502	539,872	566,665	577,858
#1 Ret Early - #2 SCR Early - Opt	03	315,529	340,797	359,754	337,301	368,129	393,253	376,043	405,930	426,398	409,084	447,970	469,915	320,511	333,687	357,265	365,801
#1 Ret Early - #2 SCR Early - CC	04	315,529	340,797	359,754	337,301	368,129	393,253	376,043	405,930	426,398	409,084	447,970	469,915	320,511	333,687	357,265	365,801
#1 Ret Early - #2 SCR Early - CT Wind	05	306,985	331,401	350,284	329,059	358,910	383,415	370,155	398,051	419,724	402,924	441,899	463,107	315,832	330,170	352,974	359,542
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	304,192	328,587	347,181	325,900	356,277	380,327	368,161	395,659	417,303	401,453	440,622	462,439	314,706	328,792	351,616	358,552
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	307,094	331,817	350,482	328,830	359,581	383,587	370,135	399,294	420,798	404,257	443,332	465,304	316,626	331,197	354,328	361,492
#1 Ret Late - #2 SCR Late - Opt	08	316,522	340,797	359,754	337,301	368,129	393,253	376,043	405,930	426,398	409,084	447,970	469,915	320,511	333,687	357,265	365,801
#1 Ret Late - #2 SCR Late - CC	09	316,522	340,797	359,754	337,301	368,129	393,253	376,043	405,930	426,398	409,084	447,970	469,915	320,511	333,687	357,265	365,801
#1 Ret Late - #2 SCR Late - CT Wind	10	306,972	331,401	350,284	329,059	358,910	383,415	370,155	398,051	419,724	402,924	441,899	463,107	315,832	330,170	352,974	359,542
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	304,175	328,587	347,181	325,900	356,277	380,327	368,161	395,659	417,303	401,453	440,622	462,439	314,706	328,792	351,616	358,552
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	307,073	331,817	350,482	328,830	359,581	383,587	370,135	399,294	420,798	404,257	443,332	465,304	316,626	331,197	354,328	361,492
#1 Ret Early - #2 Ret Early - Opt	13	191,726	197,868	213,168	205,112	213,078	231,679	225,673	232,654	251,347	244,244	254,341	274,406	140,057	126,002	145,580	148,574
#1 Ret Early - #2 Ret Early - CC	14	191,726	197,868	213,168	205,112	213,078	231,679	225,673	232,654	251,347	244,244	254,341	274,406	140,057	126,002	145,580	148,574
#1 Ret Early - #2 Ret Early - CT Wind	15	165,527	170,426	183,832	176,248	183,273	200,243	197,600	203,257	217,862	214,523	222,470	237,865	122,003	110,864	126,777	129,315
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	172,061	178,009	192,102	183,102	190,675	208,436	205,650	210,981	227,285	223,258	231,345	248,343	126,583	114,899	132,439	134,669
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	174,254	180,580	195,140	185,928	193,392	211,852	209,008	214,763	230,462	226,333	235,297	251,877	128,705	116,907	134,478	136,516
#1 Ret Late - #2 Ret Late - Opt	18	333,465	198,165	213,168	205,112	213,078	231,679	225,673	232,654	251,347	244,240	254,325	274,406	140,086	126,003	145,592	148,573
#1 Ret Late - #2 Ret Late - CC	19	333,465	198,165	213,168	205,112	213,078	231,679	225,673	232,654	251,347	244,240	254,325	274,406	140,086	126,003	145,592	148,573
#1 Ret Late - #2 Ret Late - CT Wind	20	322,957	170,987	183,832	176,248	183,273	200,243	197,600	203,257	217,862	214,523	222,470	237,865	122,003	110,864	126,777	129,315
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	319,925	177,696	192,102	183,102	190,675	208,436	205,650	210,981	227,285	223,258	231,345	248,343	126,583	114,899	132,439	134,669
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	323,158	180,660	195,140	185,928	193,392	211,852	209,008	214,763	230,462	226,333	235,297	251,877	128,705	116,907	134,478	136,516
Reference Case	23	444,779	472,494	480,427	478,527	511,129	526,556	540,685	573,772	577,167	591,541	638,424	643,198	523,563	542,136	567,997	579,174

Strategist Output - Annual Total Coal Consumption (000mmBtu)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
#1 SCR Early - #2 SCR Early	01	163,025	157,968	153,351	156,859	121,195	128,471	138,713	150,960	150,211	148,515	156,393	153,746
#1 SCR Late - #2 SCR Late	02	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	154,229
#1 Ret Early - #2 SCR Early - Opt	03	163,025	157,968	153,351	156,859	121,195	131,776	139,804	106,381	110,362	103,640	112,394	116,220
#1 Ret Early - #2 SCR Early - CC	04	163,025	157,968	153,351	156,859	121,195	131,776	139,804	106,381	110,362	103,640	112,394	116,220
#1 Ret Early - #2 SCR Early - CT Wind	05	163,025	157,968	153,351	156,859	121,195	131,776	139,804	104,034	108,465	101,451	109,268	112,179
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	163,025	157,968	153,351	156,859	121,195	131,776	139,804	102,847	107,207	100,316	108,172	110,939
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	163,025	157,968	153,351	156,758	120,948	131,316	139,222	103,838	108,283	101,380	109,391	112,191
#1 Ret Late - #2 SCR Late - Opt	08	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576
#1 Ret Late - #2 SCR Late - CC	09	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576
#1 Ret Late - #2 SCR Late - CT Wind	10	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	163,025	157,968	153,351	156,758	120,948	128,447	139,836	151,538	150,389	148,227	156,085	157,887
#1 Ret Early - #2 Ret Early - Opt	13	163,025	157,968	153,351	156,859	121,195	131,776	143,918	107,298	67,561	63,889	65,096	69,069
#1 Ret Early - #2 Ret Early - CC	14	163,025	157,968	153,351	156,859	121,195	131,776	143,918	107,298	67,561	63,889	65,096	69,069
#1 Ret Early - #2 Ret Early - CT Wind	15	163,025	157,968	153,351	156,859	121,195	131,776	143,918	104,645	58,977	55,620	56,271	59,021
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	163,025	157,968	153,351	156,859	121,195	131,776	143,918	103,499	61,342	57,852	58,652	61,496
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	163,025	157,968	153,351	156,758	120,948	131,316	143,288	104,497	62,158	58,658	59,442	62,536
#1 Ret Late - #2 Ret Late - Opt	18	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576
#1 Ret Late - #2 Ret Late - CC	19	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576
#1 Ret Late - #2 Ret Late - CT Wind	20	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	163,025	157,968	153,351	156,758	120,948	128,447	139,836	151,538	150,389	148,227	156,085	157,887
Reference Case	23	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	154,256

Scenario Name	Scenario #	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	153,159	158,582	155,380	151,459	158,114	158,985	159,510	165,125	162,691	163,536	172,604	170,466	138,037	140,117	144,226	144,248
#1 SCR Late - #2 SCR Late	02	153,159	158,582	155,380	151,459	158,114	158,985	159,510	165,125	162,691	163,536	172,604	170,466	138,037	140,117	144,226	144,248
#1 Ret Early - #2 SCR Early - Opt	03	108,576	114,174	116,057	106,379	113,325	118,398	110,584	116,580	119,899	112,702	120,667	124,252	84,836	86,604	90,930	91,313
#1 Ret Early - #2 SCR Early - CC	04	108,576	114,174	116,057	106,379	113,325	118,398	110,584	116,580	119,899	112,702	120,667	124,252	84,836	86,604	90,930	91,313
#1 Ret Early - #2 SCR Early - CT Wind	05	105,645	111,034	112,982	103,767	110,469	115,415	108,844	114,298	118,015	110,998	119,025	122,449	83,598	85,692	89,838	89,751
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	104,682	110,088	111,968	102,759	109,648	114,474	108,250	113,602	117,327	110,589	118,675	122,269	83,300	85,334	89,493	89,504
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	105,680	111,172	113,044	103,691	110,676	115,465	108,835	114,658	118,317	111,363	119,410	123,033	83,808	85,958	90,183	90,238
#1 Ret Late - #2 SCR Late - Opt	08	108,921	114,174	116,057	106,379	113,325	118,398	110,584	116,580	119,899	112,702	120,667	124,252	84,836	86,604	90,930	91,313
#1 Ret Late - #2 SCR Late - CC	09	108,921	114,174	116,057	106,379	113,325	118,398	110,584	116,580	119,899	112,702	120,667	124,252	84,836	86,604	90,930	91,313
#1 Ret Late - #2 SCR Late - CT Wind	10	105,641	111,034	112,982	103,767	110,469	115,415	108,844	114,298	118,015	110,998	119,025	122,449	83,598	85,692	89,838	89,751
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	104,676	110,088	111,968	102,759	109,648	114,474	108,250	113,602	117,327	110,589	118,675	122,269	83,300	85,334	89,493	89,504
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	105,673	111,172	113,044	103,691	110,676	115,465	108,835	114,658	118,317	111,363	119,410	123,033	83,808	85,958	90,183	90,238
#1 Ret Early - #2 Ret Early - Opt	13	65,513	65,673	67,741	63,821	64,535	68,715	65,470	65,719	69,628	66,380	67,396	71,475	37,072	32,702	37,053	37,088
#1 Ret Early - #2 Ret Early - CC	14	65,513	65,673	67,741	63,821	64,535	68,715	65,470	65,719	69,628	66,380	67,396	71,475	37,072	32,702	37,053	37,088
#1 Ret Early - #2 Ret Early - CT Wind	15	56,594	56,604	58,412	54,819	55,494	59,383	57,311	57,412	60,348	58,297	58,959	61,957	32,293	28,773	32,267	32,280
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	58,833	59,124	61,027	56,945	57,726	61,811	59,644	59,583	62,950	60,665	61,304	64,684	33,505	29,821	33,708	33,617
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	59,585	59,976	61,997	57,830	58,549	62,823	60,623	60,655	63,832	61,501	62,351	65,605	34,067	30,342	34,227	34,078
#1 Ret Late - #2 Ret Late - Opt	18	114,813	65,775	67,741	63,821	64,535	68,715	65,470	65,719	69,628	66,379	67,391	71,475	37,079	32,703	37,056	37,088
#1 Ret Late - #2 Ret Late - CC	19	114,813	65,775	67,741	63,821	64,535	68,715	65,470	65,719	69,628	66,379	67,391	71,475	37,079	32,703	37,056	37,088
#1 Ret Late - #2 Ret Late - CT Wind	20	111,201	56,789	58,412	54,819	55,494	59,383	57,311	57,412	60,348	58,297	58,959	61,957	32,293	28,773	32,267	32,280
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	110,155	59,015	61,027	56,945	57,726	61,811	59,644	59,583	62,950	60,665	61,304	64,684	33,505	29,821	33,708	33,617
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	111,268	60,001	61,997	57,830	58,549	62,823	60,623	60,655	63,832	61,501	62,351	65,605	34,067	30,342	34,227	34,078
Reference Case	23	153,554	158,890	155,851	151,871	158,346	159,408	159,989	165,853	163,207	163,984	173,077	171,032	138,582	140,705	144,565	144,577

Appendix E

Present Value Revenue Requirements Results and Annual Details

Strategist Output - Annual CO2 Emmissions (Tons)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,469,968	19,138,736	20,282,412	20,065,562	19,758,518	20,637,190	19,897,188	20,411,360	20,871,368	20,604,666	20,122,488	20,916,108	21,300,712	23,123,498	23,610,804	23,652,838	25,542,680	28,000,730	27,959,658	26,212,086	26,368,510	26,530,686	26,632,396
#1 SCR Late - #2 SCR Late	02	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010	19,771,282	20,652,892	19,926,148	20,411,360	20,871,368	20,604,666	20,122,488	20,916,108	21,300,712	23,123,498	23,610,804	23,652,838	25,542,680	28,000,730	27,959,658	26,212,086	26,368,510	26,530,686	26,632,396
#1 Ret Early - #2 SCR Early - Opt	03	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,204,778	17,426,228	17,348,986	16,790,162	17,788,438	17,392,196	17,457,236	17,943,484	17,990,540	17,110,446	17,912,602	18,512,706	19,847,360	20,327,742	20,743,020	22,097,982	24,486,556	24,829,610	22,561,308	22,767,660	22,897,764	23,047,802
#1 Ret Early - #2 SCR Early - CC	04	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,204,778	17,426,228	17,348,986	16,790,162	17,788,438	17,392,196	17,457,236	17,943,484	17,990,540	17,110,446	17,912,602	18,512,706	19,847,360	20,327,742	20,743,020	22,097,982	24,486,556	24,829,610	22,561,308	22,767,660	22,897,764	23,047,802
#1 Ret Early - #2 SCR Early - CT Wind	05	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,204,778	16,367,132	16,432,772	15,851,618	16,769,631	16,362,045	16,502,067	16,955,712	16,957,928	16,101,767	16,917,306	17,547,274	18,896,406	19,354,546	19,856,262	21,220,048	23,551,602	23,731,826	21,711,680	21,876,240	22,019,154	22,043,412
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,204,778	15,830,560	15,919,027	15,327,839	16,244,110	15,830,763	16,002,621	16,459,709	16,480,517	15,650,396	16,440,813	17,095,002	18,416,210	18,897,052	19,376,710	20,745,822	23,074,762	23,313,124	21,212,678	21,407,612	21,544,840	21,584,176
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	22,121,398	21,226,352	20,852,500	20,636,262	18,427,550	18,537,896	19,055,244	16,116,240	16,189,694	15,602,552	16,522,310	16,104,190	16,259,403	16,704,409	16,731,751	15,887,773	16,680,963	17,335,036	18,639,920	19,151,104	19,638,948	21,027,476	23,359,496	23,604,358	21,510,228	21,701,502	21,826,034	21,860,806
#1 Ret Late - #2 SCR Late - Opt	08	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010	19,771,282	20,652,892	20,193,612	17,616,708	17,943,484	17,990,540	17,110,446	17,912,604	18,512,706	19,847,360	20,327,742	20,743,020	22,097,982	24,486,556	24,829,610	22,561,308	22,767,660	22,897,764	23,047,802
#1 Ret Late - #2 SCR Late - CC	09	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010	19,771,282	20,652,892	20,193,612	17,616,708	17,943,484	17,990,540	17,110,446	17,912,604	18,512,706	19,847,360	20,327,742	20,743,020	22,097,982	24,486,556	24,829,610	22,561,308	22,767,660	22,897,764	23,047,802
#1 Ret Late - #2 SCR Late - CT Wind	10	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010	19,771,282	20,652,892	20,193,612	16,505,053	16,955,710	16,957,926	16,101,767	16,917,304	17,547,274	18,896,406	19,354,546	19,856,266	21,220,048	23,551,602	23,731,826	21,711,680	21,876,240	22,019,148	22,043,412
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010	19,771,282	20,652,892	20,193,612	16,005,568	16,459,709	16,480,517	15,650,396	16,440,812	17,095,002	18,416,210	18,897,052	19,376,710	20,745,822	23,074,764	23,313,124	21,212,678	21,407,612	21,544,838	21,584,176
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	22,121,398	21,226,352	20,852,500	20,636,262	18,427,550	18,375,626	19,093,598	20,166,822	19,934,612	19,588,264	20,468,702	20,004,668	16,262,343	16,704,410	16,731,751	15,887,773	16,680,963	17,335,036	18,639,920	19,151,104	19,638,948	21,027,474	23,359,496	23,604,358	21,510,228	21,701,502	21,826,032	21,860,808
#1 Ret Early - #2 Ret Early - Opt	13	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,456,810	17,482,488	14,512,024	14,065,068	14,665,515	14,268,678	14,584,787	14,701,637	14,775,162	14,235,429	14,602,437	15,191,934	16,769,786	16,868,944	17,321,760	18,909,522	20,773,728	21,150,556	19,223,200	18,985,752	19,188,852	19,215,196
#1 Ret Early - #2 Ret Early - CC	14	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,456,810	17,482,488	14,512,024	14,065,068	14,665,515	14,268,678	14,584,787	14,701,637	14,775,162	14,235,429	14,602,437	15,191,934	16,769,786	16,868,944	17,321,760	18,909,522	20,773,728	21,150,556	19,223,200	18,985,752	19,188,852	19,215,196
#1 Ret Early - #2 Ret Early - CT Wind	15	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,456,810	16,402,288	11,062,863	10,721,401	11,187,283	10,876,297	11,195,469	11,335,113	11,323,442	10,850,459	11,269,784	11,788,930	13,100,129	13,254,104	13,775,245	15,173,800	16,752,290	17,020,204	15,474,942	15,345,909	15,468,689	15,504,804
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,456,810	15,866,473	11,049,762	10,681,722	11,181,825	10,824,819	11,147,056	11,296,737	11,296,499	10,779,658	11,202,975	11,735,592	13,118,588	13,259,996	13,794,679	15,279,909	16,967,082	17,197,696	15,573,580	15,399,684	15,574,697	15,578,415
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	22,121,398	21,226,352	20,852,500	20,636,262	18,427,550	18,537,896	19,306,804	16,152,491	11,233,207	10,863,271	11,362,012	11,019,984	11,322,365	11,485,772	11,500,783	10,964,177	11,382,340	11,944,963	13,332,216	13,476,853	13,999,642	15,526,268	17,231,164	17,452,850	15,796,827	15,638,604	15,800,882	15,801,619
#1 Ret Late - #2 Ret Late - Opt	18	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010	19,771,282	20,652,892	20,193,612	17,977,492	14,749,847	14,775,161	14,235,430	14,602,437	15,191,935	16,769,786	16,868,944	17,321,760	18,908,834	20,786,558	21,154,602	19,217,958	18,975,260	19,185,122	19,216,316
#1 Ret Late - #2 Ret Late - CC	19	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010	19,771,282	20,652,892	20,193,612	17,977,492	14,749,847	14,775,161	14,235,430	14,602,437	15,191,935	16,769,786	16,868,944	17,321,760	18,908,834	20,786,558	21,154,602	19,217,958	18,975,260	19,185,122	19,216,316
#1 Ret Late - #2 Ret Late - CT Wind	20	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010	19,771,282	20,652,892	20,193,612	16,835,752	11,328,315	11,323,441	10,850,459	11,269,784	11,788,930	13,100,129	13,254,104	13,775,245	15,173,799	16,752,290	17,020,206	15,474,942	15,345,909	15,468,690	15,504,804
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010	19,771,282	20,652,892	20,193,612	16,346,024	11,278,184	11,296,499	10,779,658	11,202,976	11,735,592	13,118,588	13,259,996	13,794,679	15,279,909	16,967,082	17,197,696	15,573,580	15,399,684	15,574,696	15,578,416
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	22,121,398	21,226,352	20,852,500	20,636,262	18,427,550	18,375,626	19,093,598	20,166,822	19,934,612	19,588,264	20,468,702	20,004,668	16,606,318	11,475,726	11,500,783	10,964,177	11,382,340	11,944,963	13,332,216	13,476,853	13,999,642	15,526,268	17,231,164	17,452,848	15,796,829	15,638,604	15,800,882	15,801,615
Reference Case	23	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010	19,771,282	20,652,892	19,926,302	20,431,962	20,883,602	20,631,158	20,146,354	20,926,496	21,320,750	23,148,000	23,649,784	23,679,828	25,566,100	28,027,042	27,993,318	26,244,288	26,404,428	26,547,820	26,649,012

Strategist Output - Annual CO2 Costs ($000)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	0	0	0	0	368,461	390,249	423,794	447,758	455,003	456,840	485,672	477,300	507,152	533,476	535,615	537,689	574,417	601,041	653,384	686,257	705,170	771,391	862,629	883,512	833,619	864,626	895,051	921,918
#1 SCR Late - #2 SCR Late	02	0	0	0	0	368,461	390,936	426,391	449,599	456,340	457,488	486,348	478,209	507,152	533,476	535,615	537,689	574,417	601,041	653,384	686,257	705,170	771,391	862,629	883,512	833,619	864,626	895,051	921,918
#1 Ret Early - #2 SCR Early - Opt	03	0	0	0	0	368,461	396,370	425,446	371,113	387,389	377,063	403,795	406,448	421,478	445,855	456,523	445,353	480,859	516,529	549,269	581,263	609,897	658,051	745,056	775,793	710,154	734,541	764,146	787,817
#1 Ret Early - #2 SCR Early - CC	04	0	0	0	0	368,461	396,370	425,446	371,113	387,389	377,063	403,795	406,448	421,478	445,855	456,523	445,353	480,859	516,529	549,269	581,263	609,897	658,051	745,056	775,793	710,154	734,541	764,146	787,817
#1 Ret Early - #2 SCR Early - CT Wind	05	0	0	0	0	368,461	396,370	425,446	346,908	362,562	351,627	376,832	378,102	393,539	418,109	429,624	420,242	453,493	487,190	518,209	549,527	578,152	620,629	704,653	741,902	666,286	692,218	719,518	744,666
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	0	0	0	0	368,461	396,370	425,446	338,461	353,588	343,041	368,398	369,389	384,637	408,890	419,675	409,255	443,733	475,735	508,529	538,264	567,355	610,442	694,652	730,093	656,172	680,671	708,429	733,358
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	0	0	0	0	367,585	394,581	422,853	343,476	358,961	348,344	374,249	374,860	390,386	415,107	425,838	415,355	450,229	482,170	515,327	546,115	574,311	617,030	702,277	737,862	663,065	688,615	717,206	743,013
#1 Ret Late - #2 SCR Late - Opt	08	0	0	0	0	368,461	390,936	426,391	449,599	456,340	457,488	486,348	486,747	419,154	445,855	456,523	445,353	480,859	516,529	549,269	581,263	609,897	658,051	745,056	775,793	710,154	734,541	764,146	787,817
#1 Ret Late - #2 SCR Late - CC	09	0	0	0	0	368,461	390,936	426,391	449,599	456,340	457,488	486,348	486,747	419,154	445,855	456,523	445,353	480,859	516,529	549,269	581,263	609,897	658,051	745,056	775,793	710,154	734,541	764,146	787,817
#1 Ret Late - #2 SCR Late - CT Wind	10	0	0	0	0	368,461	390,936	426,391	449,599	456,340	457,488	486,348	486,747	393,350	418,109	429,624	420,242	453,493	487,190	518,209	549,527	578,152	620,629	704,653	741,902	666,286	692,218	719,518	744,666
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	0	0	0	0	368,461	390,936	426,391	449,599	456,340	457,488	486,348	486,747	384,463	408,890	419,675	409,255	443,733	475,735	508,529	538,264	567,355	610,442	694,652	730,093	656,172	680,671	708,429	733,358
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	0	0	0	0	367,585	389,215	423,802	446,815	453,229	454,478	483,209	483,663	390,208	415,107	425,838	415,355	450,229	482,170	515,327	546,115	574,311	617,030	702,277	737,862	663,065	688,615	717,206	743,013
#1 Ret Early - #2 Ret Early - Opt	13	0	0	0	0	368,461	396,370	432,243	372,605	312,972	307,876	316,819	317,949	338,802	350,688	359,194	358,780	379,498	409,986	452,663	470,101	496,942	553,146	625,348	654,235	597,344	605,886	629,565	653,189
#1 Ret Early - #2 Ret Early - CC	14	0	0	0	0	368,461	396,370	432,243	372,605	312,972	307,876	316,819	317,949	338,802	350,688	359,194	358,780	379,498	409,986	452,663	470,101	496,942	553,146	625,348	654,235	597,344	605,886	629,565	653,189
#1 Ret Early - #2 Ret Early - CT Wind	15	0	0	0	0	368,461	396,370	432,243	347,954	227,939	223,753	231,227	231,047	247,960	257,754	266,441	267,647	282,712	308,117	341,735	356,589	379,803	426,424	484,193	511,228	456,589	460,868	481,778	500,043
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	0	0	0	0	368,461	396,370	432,243	339,596	231,864	227,090	235,035	234,902	251,513	262,079	270,694	270,162	286,322	312,939	347,432	361,325	385,865	431,674	489,955	520,544	460,868	466,841	487,164	506,828
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	0	0	0	0	367,585	394,581	429,482	344,629	235,912	231,077	238,999	239,386	256,027	266,827	275,684	275,206	291,337	318,633	353,781	368,058	391,764	437,640	498,358	528,662	468,998	473,991	494,935	514,830
#1 Ret Late - #2 Ret Late - Opt	18	0	0	0	0	368,461	390,936	426,391	449,599	456,340	457,488	486,348	486,747	430,757	351,347	359,194	358,780	379,498	409,986	452,663	470,101	496,942	553,159	624,872	654,084	597,533	606,284	629,703	653,138
#1 Ret Late - #2 Ret Late - CC	19	0	0	0	0	368,461	390,936	426,391	449,599	456,340	457,488	486,348	486,747	430,757	351,347	359,194	358,780	379,498	409,986	452,663	470,101	496,942	553,159	624,872	654,084	597,533	606,284	629,703	653,138
#1 Ret Late - #2 Ret Late - CT Wind	20	0	0	0	0	368,461	390,936	426,391	449,599	456,340	457,488	486,348	486,747	405,258	258,764	266,441	267,647	282,712	308,117	341,734	356,589	379,803	426,424	484,193	511,228	456,589	460,868	481,778	500,043
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	0	0	0	0	368,461	390,936	426,391	449,599	456,340	457,488	486,348	486,747	395,768	261,989	270,694	270,162	286,322	312,939	347,432	361,325	385,865	431,674	489,955	520,544	460,868	466,841	487,164	506,828
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	0	0	0	0	367,585	389,215	423,802	446,815	453,229	454,478	483,209	483,663	401,639	267,447	275,684	275,206	291,337	318,633	353,781	368,058	391,764	437,640	498,358	528,662	468,998	473,991	494,935	514,830
Reference Case	23	0	0	0	0	368,461	390,936	426,391	449,599	456,340	457,488	486,348	478,292	507,991	534,201	536,602	538,555	574,984	602,069	654,538	687,987	706,414	772,527	863,862	884,960	835,019	866,152	896,084	922,947

Appendix E
Present Value Revenue Requirements Results and Annual Details

Strategist Output - Annual SO2 Emmissions (Tons)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
#1 SCR Early - #2 SCR Early	01	33,880	27,715	23,932	20,798	17,015	14,690	13,844	16,255	16,230	16,457	16,879
#1 SCR Late - #2 SCR Late	02	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850
#1 Ret Early - #2 SCR Early - Opt	03	33,880	27,715	23,932	20,798	17,015	14,405	13,876	16,031	14,889	15,672	16,701
#1 Ret Early - #2 SCR Early - CC	04	33,880	27,715	23,932	20,798	17,015	14,405	13,876	16,031	14,889	15,672	16,701
#1 Ret Early - #2 SCR Early - CT Wind	05	33,880	27,715	23,932	20,798	17,015	14,405	13,876	15,730	15,260	15,899	16,693
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	33,880	27,715	23,932	20,798	17,015	14,405	13,876	14,886	14,581	15,084	15,833
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	33,880	27,715	23,932	20,709	16,826	14,221	13,685	15,268	14,867	15,423	16,119
#1 Ret Late - #2 SCR Late - Opt	08	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850
#1 Ret Late - #2 SCR Late - CC	09	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850
#1 Ret Late - #2 SCR Late - CT Wind	10	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	33,880	27,715	23,932	20,709	16,826	14,482	13,704	15,953	15,990	16,115	16,563
#1 Ret Early - #2 Ret Early - Opt	13	33,880	27,715	23,932	20,798	17,015	14,405	13,825	16,049	14,216	14,335	16,057
#1 Ret Early - #2 Ret Early - CC	14	33,880	27,715	23,932	20,798	17,015	14,405	13,825	16,049	14,216	14,335	16,057
#1 Ret Early - #2 Ret Early - CT Wind	15	33,880	27,715	23,932	20,798	17,015	14,405	13,825	15,722	13,694	13,780	14,882
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	33,880	27,715	23,932	20,798	17,015	14,405	13,825	14,868	13,190	13,283	14,470
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	33,880	27,715	23,932	20,709	16,826	14,221	13,656	15,249	13,342	13,459	14,638
#1 Ret Late - #2 Ret Late - Opt	18	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850
#1 Ret Late - #2 Ret Late - CC	19	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850
#1 Ret Late - #2 Ret Late - CT Wind	20	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	33,880	27,715	23,932	20,709	16,826	14,482	13,704	15,953	15,990	16,115	16,563
Reference Case	23	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850

Scenario Name	Scenario #	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	17,108	16,347	15,713	16,138	15,351	14,645	14,957	17,190	16,541	16,719	18,213	18,997	18,726	18,543	17,300	17,524	17,208
#1 SCR Late - #2 SCR Late	02	17,105	16,347	15,713	16,138	15,351	14,645	14,957	17,190	16,541	16,719	18,213	18,997	18,726	18,543	17,300	17,524	17,208
#1 Ret Early - #2 SCR Early - Opt	03	16,579	15,688	15,152	15,477	14,501	13,703	13,510	15,714	14,869	15,232	16,181	16,802	16,860	15,782	15,159	15,020	14,952
#1 Ret Early - #2 SCR Early - CC	04	16,579	15,688	15,152	15,477	14,501	13,703	13,510	15,714	14,869	15,232	16,181	16,802	16,860	15,782	15,159	15,020	14,952
#1 Ret Early - #2 SCR Early - CT Wind	05	16,588	15,924	15,114	15,064	13,867	13,388	13,485	15,980	15,000	15,653	17,258	17,958	16,397	17,461	16,410	16,449	15,562
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	15,697	15,180	14,413	14,508	13,537	12,764	13,151	15,289	14,573	15,040	16,600	17,231	16,113	16,610	15,823	15,751	14,933
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	16,050	15,417	14,557	14,704	13,697	12,897	13,308	15,291	14,648	15,271	16,952	17,485	16,427	17,049	16,145	15,964	15,056
#1 Ret Late - #2 SCR Late - Opt	08	16,998	16,756	15,152	15,477	14,501	13,703	13,510	15,714	14,869	15,232	16,181	16,802	16,860	15,782	15,159	15,020	14,952
#1 Ret Late - #2 SCR Late - CC	09	16,998	16,756	15,152	15,477	14,501	13,703	13,510	15,714	14,869	15,232	16,181	16,802	16,860	15,782	15,159	15,020	14,952
#1 Ret Late - #2 SCR Late - CT Wind	10	16,998	15,967	15,114	15,064	13,867	13,388	13,485	15,980	15,000	15,653	17,258	17,958	16,397	17,461	16,410	16,449	15,562
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	16,998	15,220	14,413	14,508	13,537	12,764	13,151	15,289	14,573	15,040	16,600	17,231	16,113	16,610	15,823	15,751	14,933
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	16,667	15,457	14,557	14,704	13,697	12,897	13,308	15,291	14,648	15,271	16,952	17,485	16,427	17,049	16,145	15,964	15,056
#1 Ret Early - #2 Ret Early - Opt	13	15,907	14,924	14,275	14,674	13,473	12,446	12,536	14,231	13,208	13,680	14,306	14,034	14,187	13,319	12,156	12,661	11,736
#1 Ret Early - #2 Ret Early - CC	14	15,907	14,924	14,275	14,674	13,473	12,446	12,536	14,231	13,208	13,680	14,306	14,034	14,187	13,319	12,156	12,661	11,736
#1 Ret Early - #2 Ret Early - CT Wind	15	14,799	14,273	13,735	13,494	12,000	11,803	11,952	13,576	12,862	13,585	14,442	14,503	13,802	14,076	13,634	13,586	12,922
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	14,232	13,744	13,154	12,987	11,551	11,221	11,307	13,121	12,454	13,147	14,459	14,897	13,700	14,189	13,346	13,665	12,709
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	14,414	13,833	13,291	13,188	11,675	11,317	11,465	13,230	12,546	13,298	14,785	15,026	13,852	14,224	13,573	13,789	12,802
#1 Ret Late - #2 Ret Late - Opt	18	16,998	16,665	14,423	14,674	13,473	12,446	12,536	14,231	13,208	13,680	14,301	14,146	14,222	13,276	12,066	12,630	11,746
#1 Ret Late - #2 Ret Late - CC	19	16,998	16,665	14,423	14,674	13,473	12,446	12,536	14,231	13,208	13,680	14,301	14,146	14,222	13,276	12,066	12,630	11,746
#1 Ret Late - #2 Ret Late - CT Wind	20	16,998	15,691	13,578	13,494	12,000	11,803	11,952	13,576	12,862	13,585	14,442	14,503	13,802	14,076	13,634	13,586	12,922
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	16,998	15,071	13,073	12,987	11,551	11,221	11,307	13,121	12,454	13,147	14,459	14,897	13,700	14,189	13,346	13,665	12,709
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	16,667	15,311	13,158	13,188	11,675	11,317	11,465	13,230	12,546	13,298	14,785	15,026	13,852	14,224	13,573	13,789	12,802
Reference Case	23	17,094	16,320	15,668	16,122	15,343	14,619	14,917	17,157	16,506	16,692	18,186	18,975	18,716	18,535	17,299	17,494	17,179

Strategist Output - Annual NOx Emmissions (Tons)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
#1 SCR Early - #2 SCR Early	01	30,011	27,634	23,160	20,519	16,991	13,514	11,146	12,234	12,335	12,378	12,539
#1 SCR Late - #2 SCR Late	02	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368
#1 Ret Early - #2 SCR Early - Opt	03	30,011	27,634	23,160	20,519	16,991	15,119	13,520	12,555	11,847	12,295	12,813
#1 Ret Early - #2 SCR Early - CC	04	30,011	27,634	23,160	20,519	16,991	15,119	13,520	12,555	11,847	12,295	12,813
#1 Ret Early - #2 SCR Early - CT Wind	05	30,011	27,634	23,160	20,519	16,991	15,119	13,520	12,336	12,110	12,474	12,839
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	30,011	27,634	23,160	20,519	16,991	15,119	13,520	11,770	11,633	11,922	12,259
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	30,011	27,634	23,160	20,457	16,862	14,982	13,380	12,035	11,840	12,161	12,467
#1 Ret Late - #2 SCR Late - Opt	08	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368
#1 Ret Late - #2 SCR Late - CC	09	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368
#1 Ret Late - #2 SCR Late - CT Wind	10	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	30,011	27,634	23,160	20,457	16,862	15,028	15,115	16,672	16,559	16,630	17,152
#1 Ret Early - #2 Ret Early - Opt	13	30,011	27,634	23,160	20,519	16,991	15,119	15,358	14,819	11,833	11,802	12,799
#1 Ret Early - #2 Ret Early - CC	14	30,011	27,634	23,160	20,519	16,991	15,119	15,358	14,819	11,833	11,802	12,799
#1 Ret Early - #2 Ret Early - CT Wind	15	30,011	27,634	23,160	20,519	16,991	15,119	15,358	14,504	11,123	11,123	11,754
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	30,011	27,634	23,160	20,519	16,991	15,119	15,358	13,896	10,880	10,882	11,562
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	30,011	27,634	23,160	20,457	16,862	14,982	15,215	14,191	11,013	11,028	11,707
#1 Ret Late - #2 Ret Late - Opt	18	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368
#1 Ret Late - #2 Ret Late - CC	19	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368
#1 Ret Late - #2 Ret Late - CT Wind	20	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	30,011	27,634	23,160	20,457	16,862	15,028	15,115	16,672	16,559	16,630	17,152
Reference Case	23	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368

Scenario Name	Scenario #	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	12,271	11,783	11,209	11,307	10,625	9,945	10,322	11,772	11,213	11,520	12,477	12,851	13,008	12,595	11,541	11,465	11,223
#1 SCR Late - #2 SCR Late	02	14,595	11,783	11,209	11,307	10,625	9,945	10,322	11,772	11,213	11,520	12,477	12,851	13,008	12,595	11,541	11,465	11,223
#1 Ret Early - #2 SCR Early - Opt	03	12,268	11,764	11,245	11,239	10,498	9,756	9,784	11,265	10,578	10,937	11,632	11,905	12,203	11,296	10,603	10,284	10,189
#1 Ret Early - #2 SCR Early - CC	04	12,268	11,764	11,245	11,239	10,498	9,756	9,784	11,265	10,578	10,937	11,632	11,905	12,203	11,296	10,603	10,284	10,189
#1 Ret Early - #2 SCR Early - CT Wind	05	12,303	11,941	11,259	11,020	10,149	9,599	9,806	11,464	10,699	11,234	12,325	12,635	11,960	12,359	11,412	11,195	10,606
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	11,707	11,437	10,783	10,634	9,896	9,174	9,551	10,998	10,392	10,819	11,884	12,156	11,743	11,803	11,016	10,743	10,199
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	11,950	11,612	10,900	10,777	10,018	9,279	9,673	11,026	10,474	10,986	12,124	12,336	11,955	12,087	11,226	10,882	10,283
#1 Ret Late - #2 SCR Late - Opt	08	16,904	12,462	11,245	11,239	10,498	9,756	9,784	11,265	10,578	10,937	11,632	11,905	12,203	11,296	10,603	10,284	10,189
#1 Ret Late - #2 SCR Late - CC	09	16,904	12,462	11,245	11,239	10,498	9,756	9,784	11,265	10,578	10,937	11,632	11,905	12,203	11,296	10,603	10,284	10,189
#1 Ret Late - #2 SCR Late - CT Wind	10	16,904	11,966	11,259	11,020	10,149	9,599	9,806	11,464	10,699	11,234	12,325	12,635	11,960	12,359	11,412	11,195	10,606
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	16,904	11,461	10,783	10,634	9,896	9,174	9,551	10,998	10,392	10,819	11,884	12,156	11,743	11,803	11,016	10,743	10,199
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	16,661	11,636	10,900	10,777	10,018	9,279	9,673	11,026	10,474	10,986	12,124	12,336	11,955	12,087	11,226	10,882	10,283
#1 Ret Early - #2 Ret Early - Opt	13	12,249	11,637	11,094	11,131	10,214	9,383	9,582	10,701	9,958	10,371	10,806	10,611	10,947	10,098	9,132	9,185	8,568
#1 Ret Early - #2 Ret Early - CC	14	12,249	11,637	11,094	11,131	10,214	9,383	9,582	10,701	9,958	10,371	10,806	10,611	10,947	10,098	9,132	9,185	8,568
#1 Ret Early - #2 Ret Early - CT Wind	15	11,260	10,937	10,494	10,144	9,052	8,734	8,959	10,050	9,512	10,081	10,676	10,667	10,489	10,412	9,925	9,662	9,212
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	10,952	10,655	10,182	9,877	8,809	8,406	8,604	9,811	9,289	9,845	10,712	10,936	10,462	10,492	9,758	9,720	9,089
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	11,106	10,746	10,302	10,032	8,917	8,496	8,737	9,919	9,385	9,972	10,944	11,050	10,586	10,542	9,916	9,812	9,161
#1 Ret Late - #2 Ret Late - Opt	18	16,904	14,904	11,233	11,131	10,214	9,383	9,582	10,701	9,958	10,371	10,803	10,678	10,968	10,072	9,078	9,166	8,574
#1 Ret Late - #2 Ret Late - CC	19	16,904	14,904	11,233	11,131	10,214	9,383	9,582	10,701	9,958	10,371	10,803	10,678	10,968	10,072	9,078	9,166	8,574
#1 Ret Late - #2 Ret Late - CT Wind	20	16,904	14,176	10,407	10,144	9,052	8,734	8,959	10,050	9,512	10,081	10,676	10,667	10,489	10,412	9,925	9,662	9,212
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	16,904	13,716	10,131	9,877	8,809	8,406	8,604	9,811	9,289	9,845	10,712	10,936	10,462	10,492	9,758	9,720	9,089
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	16,661	13,926	10,224	10,032	8,917	8,496	8,737	9,919	9,385	9,972	10,944	11,050	10,586	10,542	9,916	9,812	9,161
Reference Case	23	16,787	16,428	16,111	15,940	15,280	14,895	15,084	16,729	16,460	16,424	17,582	18,389	18,228	17,903	17,193	17,082	16,845

Strategist Output - Annual Hg Emmissions (lbs)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
#1 SCR Early - #2 SCR Early	01	608	244	199	173	154	115	93	125	122	122	131
#1 SCR Late - #2 SCR Late	02	608	244	199	173	154	114	92	124	122	121	131
#1 Ret Early - #2 SCR Early - Opt	03	608	244	199	173	154	109	92	148	128	138	154
#1 Ret Early - #2 SCR Early - CC	04	608	244	199	173	154	109	92	148	128	138	154
#1 Ret Early - #2 SCR Early - CT Wind	05	608	244	199	173	154	109	92	146	135	143	157
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	608	244	199	173	154	109	92	136	127	133	147
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	608	244	199	171	152	107	90	140	129	137	150
#1 Ret Late - #2 SCR Late - Opt	08	608	244	199	173	154	114	92	124	122	121	131
#1 Ret Late - #2 SCR Late - CC	09	608	244	199	173	154	114	92	124	122	121	131
#1 Ret Late - #2 SCR Late - CT Wind	10	608	244	199	173	154	114	92	124	122	121	131
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	608	244	199	173	154	114	92	124	122	121	131
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	608	244	199	171	152	112	90	120	119	118	127
#1 Ret Early - #2 Ret Early - Opt	13	608	244	199	173	154	109	90	147	142	142	173
#1 Ret Early - #2 Ret Early - CC	14	608	244	199	173	154	109	90	147	142	142	173
#1 Ret Early - #2 Ret Early - CT Wind	15	608	244	199	173	154	109	90	145	143	142	164
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	608	244	199	173	154	109	90	135	135	135	158
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	608	244	199	171	152	107	88	139	137	137	160
#1 Ret Late - #2 Ret Late - Opt	18	608	244	199	173	154	114	92	124	122	121	131
#1 Ret Late - #2 Ret Late - CC	19	608	244	199	173	154	114	92	124	122	121	131
#1 Ret Late - #2 Ret Late - CT Wind	20	608	244	199	173	154	114	92	124	122	121	131
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	608	244	199	173	154	114	92	124	122	121	131
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	608	244	199	171	152	112	90	120	119	118	127
Reference Case	23	608	244	199	173	154	114	92	124	122	121	131

Scenario Name	Scenario #	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	118	104	99	108	98	96	94	121	116	115	131	143	142	129	116	112	107
#1 SCR Late - #2 SCR Late	02	118	104	99	108	98	96	94	121	116	115	131	143	142	129	116	112	107
#1 Ret Early - #2 SCR Early - Opt	03	133	121	118	122	113	109	99	130	123	121	134	145	144	123	119	110	109
#1 Ret Early - #2 SCR Early - CC	04	133	121	118	122	113	109	99	130	123	121	134	145	144	123	119	110	109
#1 Ret Early - #2 SCR Early - CT Wind	05	136	126	120	119	106	106	100	135	126	128	150	161	139	147	137	130	118
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	125	117	111	112	102	99	97	126	121	120	141	152	135	136	129	121	110
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	129	120	112	114	104	100	98	126	121	123	146	155	139	142	133	123	111
#1 Ret Late - #2 SCR Late - Opt	08	114	135	118	122	113	109	99	130	123	121	134	145	144	123	119	110	109
#1 Ret Late - #2 SCR Late - CC	09	114	135	118	122	113	109	99	130	123	121	134	145	144	123	119	110	109
#1 Ret Late - #2 SCR Late - CT Wind	10	114	127	120	119	106	106	100	135	126	128	150	161	139	147	137	130	118
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	114	118	111	112	102	99	97	126	121	120	141	152	135	136	129	121	110
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	110	120	112	114	104	100	98	126	121	123	146	155	139	142	133	123	111
#1 Ret Early - #2 Ret Early - Opt	13	150	135	134	139	123	120	114	137	130	129	136	139	139	118	110	109	97
#1 Ret Early - #2 Ret Early - CC	14	150	135	134	139	123	120	114	137	130	129	136	139	139	118	110	109	97
#1 Ret Early - #2 Ret Early - CT Wind	15	144	135	134	130	111	117	113	134	130	134	144	150	141	137	136	130	121
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	135	126	125	122	104	109	103	126	124	127	143	154	137	136	131	129	116
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	137	127	126	124	104	109	104	127	124	128	147	155	139	135	133	129	116
#1 Ret Late - #2 Ret Late - Opt	18	114	130	135	139	123	120	114	137	130	129	136	140	139	117	108	109	97
#1 Ret Late - #2 Ret Late - CC	19	114	130	135	139	123	120	114	137	130	129	136	140	139	117	108	109	97
#1 Ret Late - #2 Ret Late - CT Wind	20	114	120	132	130	111	117	113	134	130	134	144	150	141	137	136	130	121
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	114	113	124	122	104	109	103	126	124	127	143	154	137	136	131	129	116
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	110	115	125	124	104	109	104	127	124	128	147	155	139	135	133	129	116
Reference Case	23	118	103	98	107	97	95	93	120	115	115	130	142	141	128	115	111	107