FOR BOARD ACTION

Agenda Item # **2** **Meeting Date:** **8/7/12**

SUBJECT:	2012 Infrastructure Update to Electric Utility Baseline Strategy for 2005 – 2030 Electric Infrastructure
PREPARED BY:	Wally Schlink Director of Power Resources

ITEM DESCRIPTION:

Since the RPU Utility Board decision to become a contract rate of delivery (CROD) member of Southern Minnesota Municipal Power Agency (SMMPA), the utility has had in place a Board approved power supply plan to meet the demand and energy needs of our customers. That plan led to the installation of Cascade Creek Unit 2, conversion to gas of Cascade Creek Unit 1, the Mayo steam supply project and increased activities in renewable energy.

In June, 2005 Burns & McDonnell developed the Electric Utility Baseline Strategy for 2005 – 2030 Electric Infrastructure Plan (commonly referred to as the Infrastructure Plan) which provided the strategic guidance plan for future infrastructure development. The plan was recognized to be a guideline document that would require updating as industry, economic, legislative, regulatory and other conditions change or emerge. The study period was focused on the power needs above CROD and through the 2030 termination date of the SMMPA Power Sales Agreement.

In July, 2009 Burns & McDonnell presented the 2009 Update to Infrastructure Plan to the Board. The focus of the update was the time period of 2025 – 2044 which include the impacts of the decision of whether to extend the SMMPA contract and what were the infrastructure options if RPU chose to become self-sufficient effective in 2030. The analysis indicated a future that takes advantage of technology to move away from carbon fuels, is primarily natural gas based, has a higher emphasis on renewables and aggressive conservation programs and incorporated market opportunities.

Kiah Harris, Director of Energy Consulting for Burns and McDonnell, will present the results of the 2012 Update to the Infrastructure Plan and be available to answer any questions. The current update was compelled by three significant events, the receipt of a Section 114(a) request from the EPA that exposed RPU to an enforcement action, a litany of emerging environmental regulations that emission modeling indicate will require substantial revisions and investment to the SLP and the results of the economic analysis on the economics of future power supply options for RPU.

UTILITY BOARD ACTION REQUESTED:

Management requests that the Board receive and place on file the 2012 Update to Infrastructure Plan and direct staff to develop and implement an execution plan that will achieve the recommendations included in the 2012 Update.

Larry Koshire — General Manager

Aug 2, 2012 — Date

ROCHESTER PUBLIC UTILITIES

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RESOLUTION

WHEREAS, the Public Utility Board of the City of Rochester, Minnesota, reviewed the 2012 Infrastructure Update to Electric Utility Baseline Strategy for 2005 – 2030 Electric Infrastructure; and

WHEREAS, Rochester Public Utilities is the subject of potential or threatened litigation by the Environmental Protection Agency under the New Source Review section of the Clean Air Act as part of the Coal Fired Power Plant Enforcement Initiative; and

WHEREAS, the Silver Lake Power Plant is subject to a significant number of future restrictive environmental regulations that will substantially affect the ability to operate the facility; and

WHEREAS, economic analysis of the cost of settlement, additional compliance measures and existing power supply options are found to be prohibitive; then

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to accept and places on file the 2012 Infrastructure Update to Electric Utility Baseline Strategy for 2005 – 2030 Electric Infrastructure; and

BE IT FURTHER RESOLVED the Public Utility Board of the City of Rochester, Minnesota directs staff to develop, implement and execute a plan, using the 2012 Update as a guideline, to decommission the Silver Lake Power Plant by December 31, 2015 or sooner.

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 7th day of August, 2012.

President

Secretary

DRAFT – REVISION 0

2012 Infrastructure Update to
Electric Utility Baseline Strategy for 2005-2030
Electric Infrastructure

Prepared for

Rochester Public Utilities

August 2012

Project 59752

Burns & McDonnell
SINCE 1898

2012 Infrastructure Update

prepared for

Rochester Public Utilities
Rochester, Minnesota

August 2012

Project No. 59752

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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EXECUTIVE SUMMARY

ES-0 EXECUTIVE SUMMARY

This report section presents a summary of the 2012 Infrastructure Update (Update). The Study was completed by Burns & McDonnell Engineering Company (B&McD) for Rochester Public Utilities (RPU). The objectives, methodology, and results of the Study are summarized in the following sections

ES.1 STUDY OBJECTIVES

B&McD was retained by Rochester Public Utilities (RPU) to perform an update to the 2005-2030 Baseline Infrastructure Study (Study) to evaluate and update as necessary the key findings and recommendations of the original long range strategy developed in 2005 and the update to the original study prepared in 2009. This report provides information on the generation resource planning and other analyses undertaken to make updated decisions and recommendations on RPU's long term strategy.

The objective of this Study Update was to analyze the power supply needs of RPU to the 2045 time frame in order to identify any longer term issues which could impact shorter term decisions. There have been significant impacts to utilities since the original Study due to:

- the economic downturn,
- costs of fuel and
- regulatory issues.

There have also been significant changes in the wholesale market in which RPU operates. These changes have been beneficial for RPU in the procurement of energy, but have virtually eliminated the ability to sell energy into the market from its coal-fired resources.

Other significant impacts to RPU include:

- the availability and price of natural gas as a generation fuel source,
- receiving a NSR Information Request from the EPA in the fall of 2010 and
- regulations affecting utility power plants that have been implemented or proposed since the last update.

These issues have significantly impacted the economics of coal fired power plants for RPU and other utilities. The EPA regulations have forced an assessment of the long term viability of the RPU coal units based on the cost to bring the facilities into compliance with the EPA proposed settlement offer under the NSR request and the new regulations. The NSR action and the current and proposed regulations developed by the Environmental Protection Agency impact the long term viability of the Silver Lake Power Plant (SLP). This analysis was primarily prompted due to a need to evaluate these EPA actions on RPU's generating units.

The Study prepared for RPU in 2005 included several supply and demand side activities which RPU could pursue. RPU has continued to aggressively pursue demand side measures that allow customers to reduce their energy consumption. The reductions have targeted an amount of 1.5 percent of the expected retail energy sales for the year. The programs include numerous appliance efficiency upgrades, lighting change out and direct load control programs.

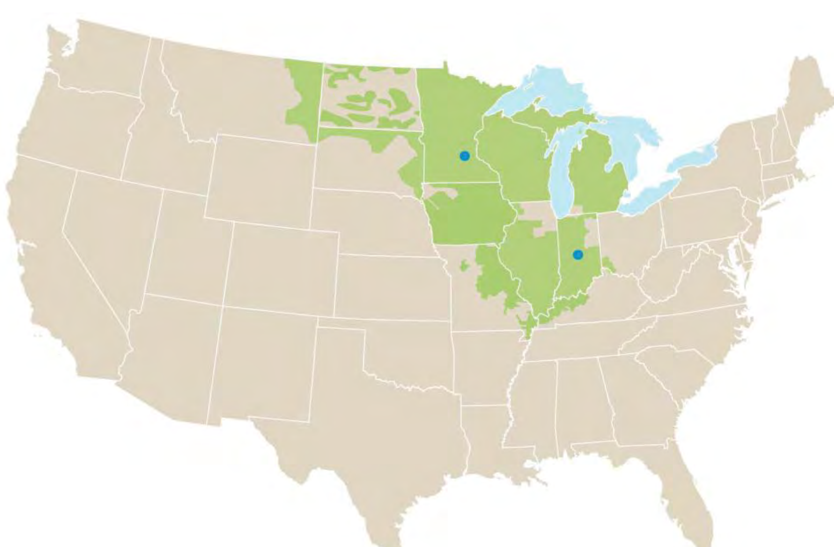
RPU is also actively engaged in transmission expansion in the vicinity through participation with regional utilities through the CapX investments. Upgrades to the 161kV transmission system around Rochester have been initiated under this program. These improvements will help alleviate current transmission constraints into the RPU area, which will benefit RPU in that it can rely more on imported power to meet its electric supply obligations. It is expected that the first phase of these transmission improvements will be in service in 2015.

ES.2 REVIEW OF CURRENT RPU POWER SUPPLY CONDITIONS

ES.2.1 MISO Market

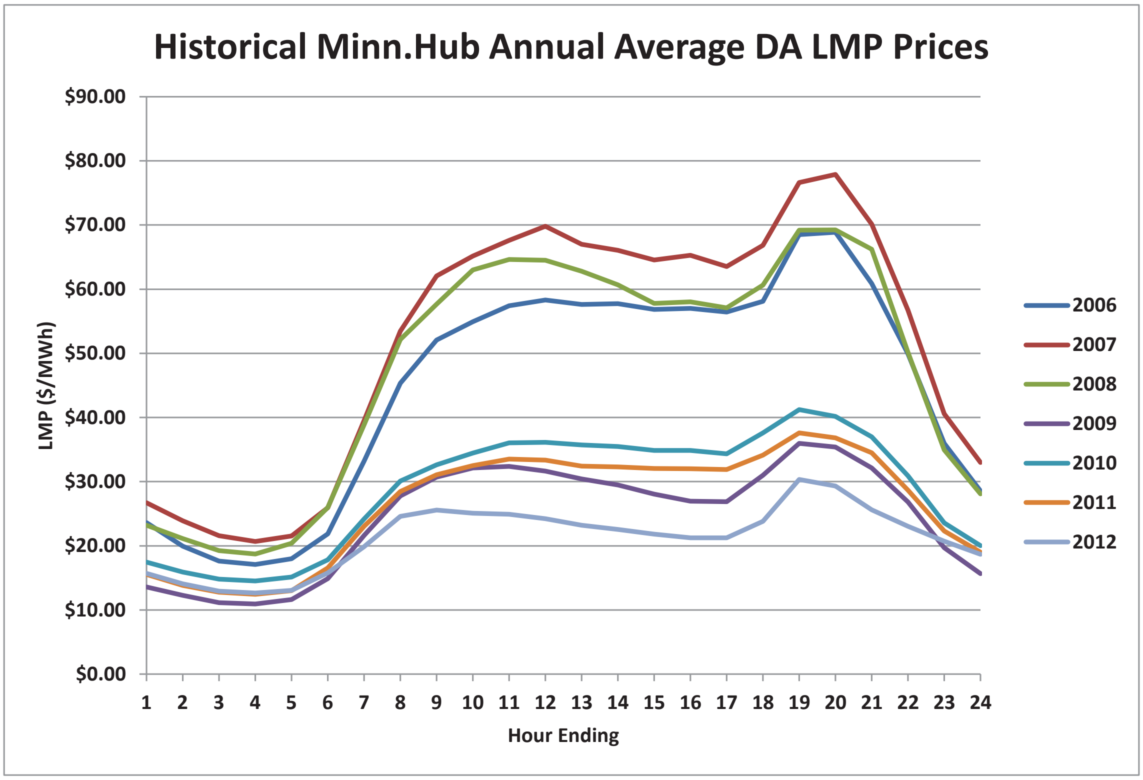
RPU is a market participant in the MISO market. The MISO market operates in the area identified in Figure ES-1.

Figure ES-1 MISO Market Area



Utilities have become more accustomed to the MISO market operations. It is common for utilities today to acquire all of their energy from the market and sell energy from their resources into the market when it is accepted for dispatch. In essence, all of the electrical energy RPU distributes above CROD is acquired from the MISO market. The cost for this energy has been affected significantly from the initial operation of the market at the time of the Study. The past few years have seen prices decline significantly from the peak year of 2007. Figure ES-2 provides annual averages of hourly locational marginal pricing for day ahead energy at the Minnesota Hub for several years.

Figure ES-2 MISO Average LMPs
Minnesota Hub



The advancement of the MISO market and current energy costs has dramatically impacted the use of the RPU Silver Lake Plant Units for sales into the market. Table ES-1 provides a comparison of dispatch hours in 2005 compared to 2011. This is a reflection of the impact the pricing of natural gas, the availability of wind energy and the economic downturn have had on the ability for utilities to dispatch the smaller coal units in to the market.

Table ES-1 Market Dispatch Hours RPU Units 2005 and 2011

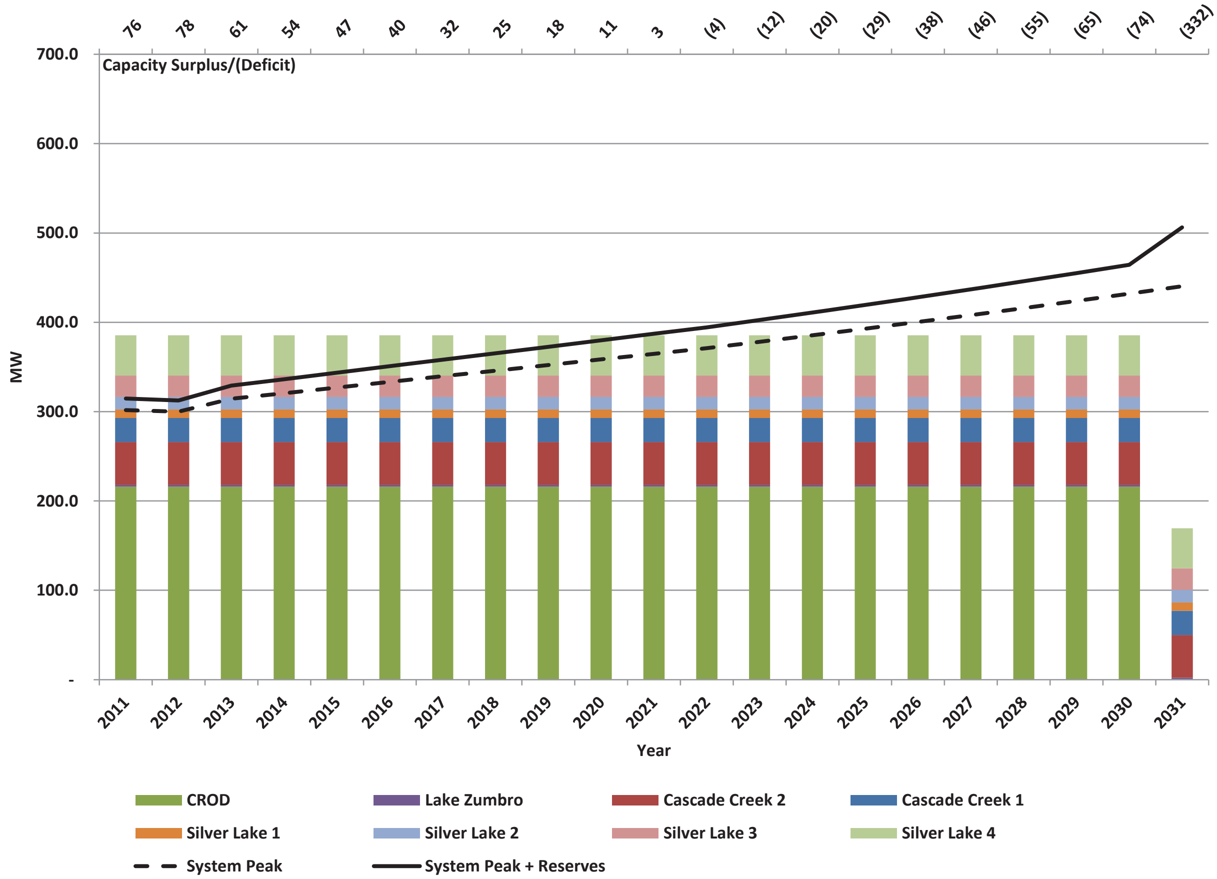
Unit	*Hours 2005*	*Hours 2011*
SLP 4	5021	58
SLP 3	4119	61
SLP 2	2913	95
SLP 1	4612	43
CC 2	384	137
CC 1	130	17

ES.2.2 RPU Loads and Resources

RPU's load forecast continues to be significantly below the initial forecast used in the 2005 Infrastructure Plan. The forecast used in this Update is based on recent SMMPA projections. The adjusted forecast can be attributed to many factors including increased DSM programs and end-user efficiency. Therefore, it is inherently assumed in the forecast that the aggressive DSM reviewed in the initial Study is capturing sufficient demand and energy to result in the SMMPA revised forecast.

RPU still is supplied the majority of its capacity and energy through the contract with the SMMPA. Other resources include the Silver Lake Power plant, the Cascade Creek combustion turbines, the Zumbro hydro facility and smaller resources with IBM, the OWEF and distributed generation in Rochester. The projected balance of loads and resources is summarized in Figure ES-3.

Figure ES-3 RPU Balance of Loads and Resources



Based on the forecast and resource mix, RPU will begin to incur capacity deficits in approximately 2021. Due to its current excess amount of capacity, RPU has entered into various contracts with area entities for capacity and energy from the Silver Lake Power Plant. The Minnesota Municipal Power Association (MMPA) and the Southern Minnesota Municipal Power Association (SMMPA) have contracted for capacity and associated as scheduled energy from the facility. The SMMPA contract terminates in 2013 and the MMPA contract terminates in late 2015.

In addition to these contracts, RPU has a steam contract with the Mayo Clinic. RPU provides Mayo with up to 50,000 pounds per hour of steam from one of the steam units. As it was originally envisioned, the operation of the SLP on coal would allow the extraction of this steam for Mayo at a benefit for both parties. Currently, the reduced hours of operation of the SLP units in the MISO market have shifted the unit operation to a gas-fired operation of a small boiler to satisfy the contract. The earliest date for termination of this contract is 2015.

ES.2.3 New Resources

The capacity and energy needs of RPU are projected to potentially increase over the study period. Two approaches were used to satisfy the capacity and energy obligations. These were satisfied either from resources owned by RPU or contracted for through the market. The current EPA regulations have removed a new coal fired power plant from consideration as a new resource. Therefore, gas-fired and renewable resources are the only realistic resource options that RPU could construct. Part 2 provides a description of the assessment included for new resources. Based on the assessment, smaller gas-fired combustion turbines and reciprocating engines were the most likely constructed options. In addition, bilateral market purchase contracts for capacity were also considered.

The forecasts for coal and natural gas have changed significantly from the Study. The coal forecast used in the original Study was estimated to cost $2.35 per mmBtu as compared to the actual cost of $4.62 per mmBtu in the current contract for coal at the SLP. The current market price for natural gas is lower than forecast due to the significant supply of natural gas resulting from the advancements in horizontal drilling and hydraulic fracturing. As a comparison, the previous EIA natural gas forecast used in the Study predicted gas to cost $7.93 per mmBtu in 2016 instead of the currently forecast $4.71 per mmBtu.

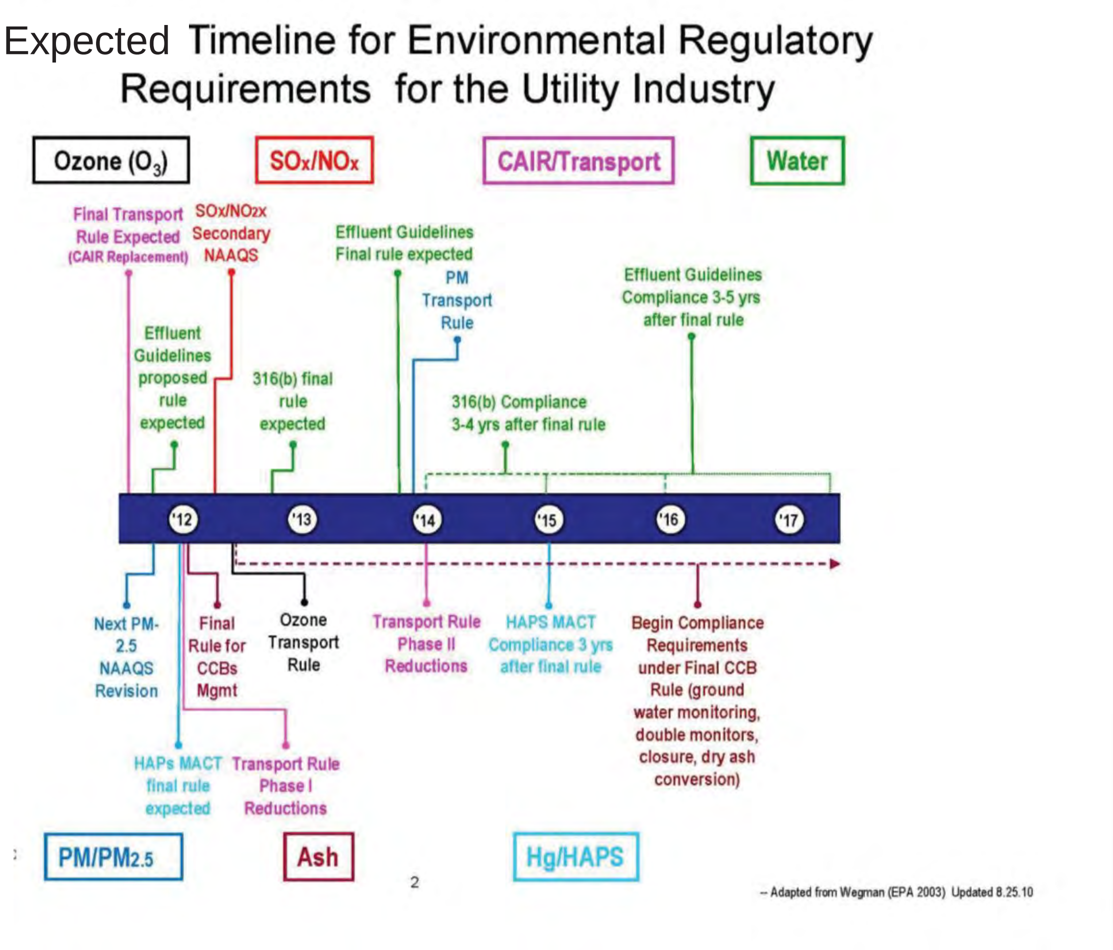
The investments being made in the CapX transmission projects provide an opportunity for RPU to reduce its reliance on internal generation to meet its reliability goals. These projects are increasing the firm import capability into the RPU service area from the 148MW limit in the Study to approximately 370MW with no RPU units dispatched and to approximately 440MW if the Cascade Creek CT2 is brought on line. This provides increased flexibility to RPU when considering the amount of generation internal to its service territory that is needed to provide high reliability to its customers.

ES.3 EPA ACTIONS

At the time of the initial Study, RPU was evaluating various upgrades to the SLP in order to meet a settlement agreement with the Minnesota Pollution Control Agency (MPCA) and the Minnesota Center for Environmental Advocacy (MCEA). This agreement was developed as a result of modifying the SLP to provide steam to the Mayo Clinic. As required by the agreement with the MPCA/MCEA new emission controls were installed and placed in service in 2009. The upgraded emission controls allowed the SLP Unit 4 to operate on coal and achieve compliance with all current and anticipated environmental regulations. These upgrades were seen as necessary in order to keep the SLP Unit 4 as a viable unit to meet contractual obligations and to provide backup power supply to the city due to the transmission limitations. It was also considered that over time, the SLP units would also be used to provide energy to meet RPU load as the load grew above the CROD.

The EPA has begun to finalize regulations that have been pending under the Clean Air Act, the Clean Water Act and the Resource Conservation and Recovery Act that affect operations of existing and construction of new power plants. Units fired by coal are the most significantly affected. Part 3 of the report describes the environmental regulations that could impact the RPU units in the future. General background information on each rule and its current status are discussed in Appendix B. Figure ES-4 provides an overview of the pending EPA actions.

Figure ES-4 Summary of Potential EPA Regulations Affecting Electric Utilities



In November 2010, the federal EPA notified RPU of a potential violation of the Clean Air Act under the Prevention of Significant Deterioration/New Source Review regulations. This process was initiated through a Section 114 Information Request delivered to RPU on November 18, 2010. The EPA and RPU discussed this issue during December 2010. RPU submitted a proposal for settlement to EPA Region 5 on January 21, 2011. On June 3, 2011, the EPA provided its Settlement Counter Proposal to RPU.

The emission rates between the EPA regulations in affect or being promulgated were compared to the settlement offer. The comparison of the major emissions indicated that, to meet the limits in the settlement counter offer, additional controls would be needed at the SLP. In addition to the limits being more restrictive under the EPA proposed NSR settlement counter offer, the time frame for compliance begins in 2012 versus the 2012 to 2017 time frame for the various EPA regulations. Conceptual estimates for bringing SLP Units 3 and 4 in to compliance with the settlement offer are provided in Table ES-2.

Table ES-2 Probable Equipment Requirements for EPA NSR Enforcement Action Settlement Offer

SLP Unit	Technology	Estimated Budget
Unit 3	Semi-dry scrubber and baghouse	$17,500,000
	SCR	$14,000,000
Unit 4	Wet FGD	$40,000,000
	SCR	$19,000,000
Total		$90,500,000

In addition to these fixed investment costs, there would be impacts to unit heat rates and operating and maintenance costs.

Another consideration in the approaches to comply with the EPA proposed NSR settlement counter offer would be to switch the SLP to operate on natural gas. The city of Rochester is served locally by the local distribution company (LDC) Minnesota Energy Resources, Co (MERC). MERC receives gas from the area interstate pipeline network at a high pressure. The pressure is reduced and distributed through a network of pipes within Rochester to retail consumers.

In consideration of switching the SLP to operate totally on natural gas, the delivery capacity of the interstate and LDC networks has to be considered. For adequate service, the pressure of the gas in the lines must be maintained as the flow volumes increase due to the SLP demand. This condition has to be satisfied for the maximum conditions, which for Rochester, occur during the winter heating season. Inquiries were made to NNG and MERC as to the capability of serving the SLP with sufficient gas to operate the units on natural gas. RPU was informed that significant upgrades to both the interstate system feeding Rochester and the LDC would be needed in order to operate the units at SLP reliably on natural gas.

ES.4 RESOURCE STRATEGY

In developing the resource strategy for RPU, several scenarios were considered. The scenarios essentially reverted to considerations of the future of SLP in light of the EPA actions and current economic conditions. Three scenarios selected for analysis in Strategist were:

1. Retire all SLP units in 2015.
2. Retire SLP units 1,2 and 3 in 2015, and
3. Keep all units at SLP operating throughout the study

Due to the CapX investment, RPU is able to acquire considerably more capacity from the market to meet its obligations and not be as concerned about resources having to be located within RPU's service territory to provide energy in case of a line outage. For purposes of the planning scenarios, a limit of 75MW was placed on the amount of capacity that RPU would acquire from the market before a unit would be constructed by RPU.

RPU constructed resource options were selected from the lower capital cost options identified in Part 2. These would include combustion turbines and reciprocating engines. All of the new dispatchable resources would be fired on natural gas as a primary fuel. It is anticipated that the smaller units would be able to be permitted with fuel oil as a backup fuel to allow purchase of gas on a non-firm basis. The resources would be added at the new site acquired on the north side of Rochester.

The resource options were reviewed with the use of a portfolio analysis model, Strategist. This model is used extensively in Minnesota and elsewhere by utilities and public service commissions to analyze a utility's future resource strategies. The model determines the annual operating costs across the study period for numerous portfolio combinations and develops net present values to allow a comparison of the portfolios. Table ES-3 provides the summary of the analysis of the three scenarios.

Table ES-3 Net Present Values of Resource Scenarios

(000,000s)

	NPV	% Diff from Scenario 1
Scenario 1-Retire All	$2,289	0
Scenario 2-Retire 1,2,3	$2,385	4.2
Scenario 3-Keep All	$2,373	3.67

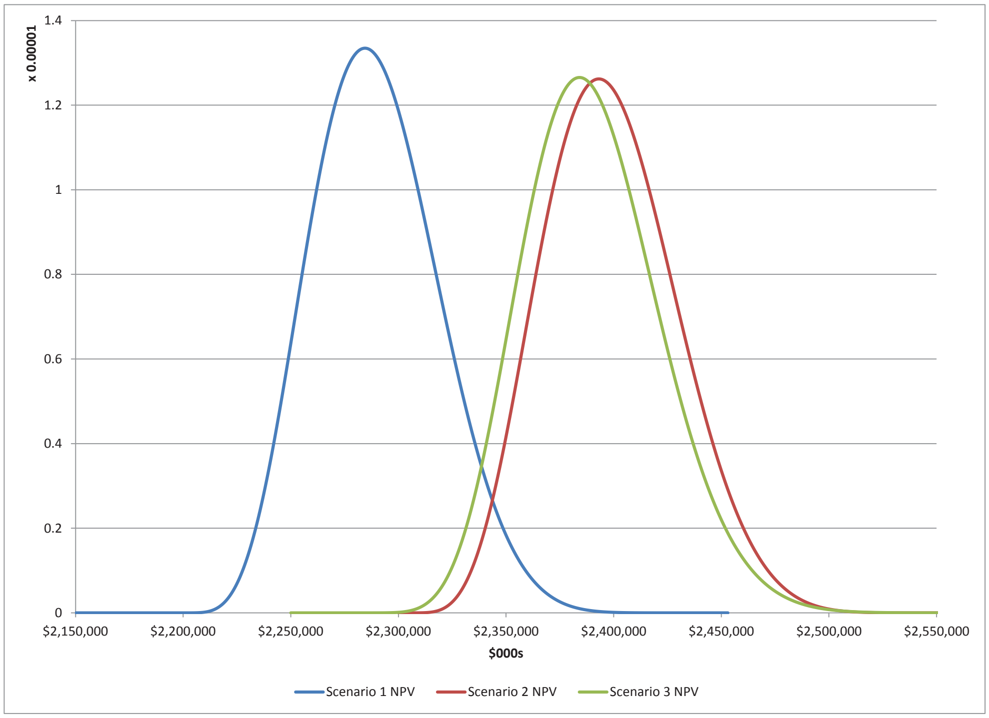
The major difference between the scenarios is the difference in the fixed operating and maintenance costs and investments in the required EPA upgrades. The reduction in fixed costs budgeted for the SLP facility between 2015 and 2021when the next resource is added amount to approximately $5 million to $5.5 million per year for the five years or approximately $25million. Part 4 provides details of these cost comparisons.

There are several assumptions associated with these scenarios. A sensitivity analysis was performed on several variables to review how changes in the assumption would impact the net present values of the three scenarios. The following assumptions were varied as indicated.

- Natural gas forecast – Increase up to $2 per mmBtu above the 2015 price with same escalation
- EPA associated capital cost – Adjust across the range of -30 percent to +20 percent
- Interest Rates – Increase up to 2 percent above current assumption
- Market capacity cost – Adjust across the range of +/- 20 percent
- Generator capital cost – adjust across the range of +/- 20 percent
- SLP coal – increase up to 5 percent

The variables were applied to the scenarios using an expected value distribution curve. The model then varied the assumptions across the range identified above to provide an overall distribution of the possible net present values. Figure ES-4 provides a summary of the results.

Figure ES-4 Sensitivity Analysis Scenario 1-3



As shown, the Scenario 1 has the higher probability of achieving the projected evaluated results and has the lower range of NPVs.

ES.5 CONCLUSIONS

Based on the analysis provided in this report to RPU on the EPA actions, the current state of the utility industry and the various scenarios associated with SLP units, Burns & McDonnell has developed the following conclusions.

1. The EPA is aggressively targeting coal-fired electrical generating units with general industry regulations tightening the allowed emissions from the units. In addition, EPA is directly targeting certain utilities with suspected violations of existing regulations under NSR of the Clean Air Act at certain coal-fired units and obtaining settlements with regards to requirements to reduce emissions from the affected coal-fired units.
2. The more onerous EPA action which affects RPU is complying with the proposed EPA NSR Enforcement Action settlement counter offer provided to RPU in June, 2011. In order for the SLP Units 3 and 4 to maintain the option to burn coal under the proposed settlement counter offer, further emission controls will be required on the units.

3. RPU is confronted with potential additional investments needed for the above emission controls at SLP and the need to acquire capacity for its capacity obligations in the 2021 time frame.
4. An analysis of various retirements versus retrofit scenarios indicates that retiring the SLP and acquiring replacement capacity from the market in the short term reduces the annual revenue requirements associated with RPU resources when compared to the two retrofit scenarios.
5. SLP Unit 4 is not anticipated to operate at any significant capacity factor in the future to meet RPU energy requirements or for energy sales into the MISO market.
6. Units developed in the future as replacements for SLP would help in positioning RPU for its post 2030 operations without the CROD. This would position RPU with assets that are more valued in the MISO market than the small coal units such as SLP Units 3 and 4. RPU's load projections are such that resource deficits will occur in approximately 2021 with the current resources and load forecast. RPU has several options to obtain capacity to fill this deficit at reasonable cost.
7. The investment that RPU is making in the CapX transmission upgrade projects is providing increased, firm access, to the area market. This reduces the need to maintain the level of generation relative to load that RPU has deemed necessary in the past to maintain the high level of reliability its customers require.
8. RPU should continue to update the analysis of its future resource plans as major changes in the industry occur or as assumptions change from those used herein.

* * * * *

SECTION 1.0
INTRODUCTION

1.0 INTRODUCTION

Burns & McDonnell Engineering Company (B&McD) was retained by Rochester Public Utilities (RPU) to perform an Update to the 2005-2030 Baseline Infrastructure Study (Study or Study Update) to evaluate and update as necessary the key findings and recommendations of the original long range strategy developed in 2005 and the update to the original study prepared in 2009. This report provides information on the generation resource planning and other analyses undertaken to make updated decisions and recommendations on RPU’s long term strategy.

1.1 STUDY OBJECTIVES

The updated analysis required to support the ongoing long term resource decisions is the subject of this report. The objective of this update was to analyze the power supply needs of RPU to the 2045 time frame in order to identify any longer term issues which could impact shorter term decisions. There have been significant impacts to utilities due to the economic downturn, costs of fuel and regulatory issues since the initial development of the Study. These impacts have created significant changes to utility operations.

There have also been significant changes in the wholesale market in which RPU operates. These changes have been beneficial for RPU in the procurement of energy, but have virtually eliminated the ability to sell energy into the market from its coal-fired resources.

Another significant impact is the availability and price of natural gas as a generation fuel source. The price projections for this fuel are much lower than were seen during the previous studies for RPU. The impacts of this low fuel pricing are to reduce the marginal price of electricity on the wholesale market and to promote fuel switching from coal to natural gas.

The primary impact to its generation resources which RPU has had to confront has been in the area of EPA actions. These actions included receiving a Clean Air Act Section 114 Information Request from the EPA in the fall of 2010 and regulations affecting utility power plants that have been implemented or proposed since the last update. These two issues have significantly impacted the economics of coal fired power plants. These regulations have forced an assessment of the long term viability of the RPU coal units based on the cost to bring the facilities into compliance with the EPA proposed settlement offer under the NSR request and the new regulations. These issues, coupled with the low forecast of the price for natural gas, have prompted many utilities to retire older coal fired units. It is anticipated that approximately 40,000 MW of coal fired capacity will be retired prior to 2016. The NSR action and these current and proposed regulations developed by the Environmental Protection Agency impact the long term viability of the Silver Lake Power Plant. This analysis was primarily prompted due to a need to evaluate these EPA actions on RPU's generating units.

1.2 STUDY BACKGROUND

The Infrastructure Study prepared for RPU in 2005 included several supply and demand side activities which RPU could pursue. RPU has continued to aggressively pursue demand side measures that allow customers to reduce their energy consumption. The reductions have targeted an amount of 1.5 percent of the expected retail energy sales for the year. The programs include numerous appliance efficiency upgrades, lighting change out and direct load control programs. This Study provides a discussion of the progress that RPU has made in the area of DSM.

RPU is also actively engaged in transmission expansion in the vicinity through participation with regional utilities through the CapX investments. Upgrades to the 161kV transmission system around Rochester have been initiated under this program. These improvements will help alleviate current transmission constraints into the RPU area, which will benefit RPU in that it can rely more on imported power to meet its electric supply obligations. It is expected that the first phase of these transmission improvements will be in service in 2015.

1.3 STUDY METHODOLOGY

The analysis of power supply options and issues associated with the EPA challenges to continued operation of the Silver Lake Power Plant required the projection of RPU's demand and energy over the study period. The forecast for the energy and demand was provided by RPU. The forecast was used as the basis for determining when additional resources would be needed to maintain the capacity reserve margins required by the Midwest Independent Transmission System Operator (MISO) and North American Electric Reliability Corporation (NERC).

The analysis of power supply options was performed using the Strategist resource expansion program. This program analyzes the capacity and energy needs of a utility and adds resources from options provided to the program. Various assumptions were developed for such things as capital costs, fixed operations and maintenance costs, fuel supply and variable operating costs of potential new resources. In addition, Burns & McDonnell developed assumptions for market costs at the SMP.RPU MISO node. The time frame for the updated resource analysis was from 2015 through 2044.

The estimates and projections contained in this report are based on Burns & McDonnell's experience, qualifications and judgment as a professional consultant and reflect screening level assumptions about the facilities represented and are not site specific. While the estimates are considered suitable for use in production cost modeling analyses to select preferable resource options to pursue, Burns & McDonnell has no control over the numerous factors affecting actual costs should any of the facilities included herein be pursued. Therefore, Burns & McDonnell does not guarantee that actual values realized over time will not vary from the estimates and projections prepared by Burns & McDonnell for purposes of this planning study.

1.4 ORGANIZATION OF REPORT

This report is organized into several separate chapters and supporting appendices. These individual sections are listed below along with a brief description of their contents.

- Executive Summary: An executive summary of the 2012 Infrastructure Update.
- Section 1.0 – Introduction: A description of the Study's objectives and methodology.
- Section 2.0 – Review of Current RPU Power Supply Conditions provides an overview of the current RPU power supply situation.
- Section 3.0 –Impacts of EPA Regulations on Silver Lake Power Plant discusses the issues EPA has created with regards to SLP
- Section 4.0 – Resource Strategy provides a resource expansion plan for RPU based on the assessment of the SLP and other options available to RPU.

* * * * *

SECTION 2.0

REVIEW OF CURRENT RPU POWER SUPPLY CONDITIONS

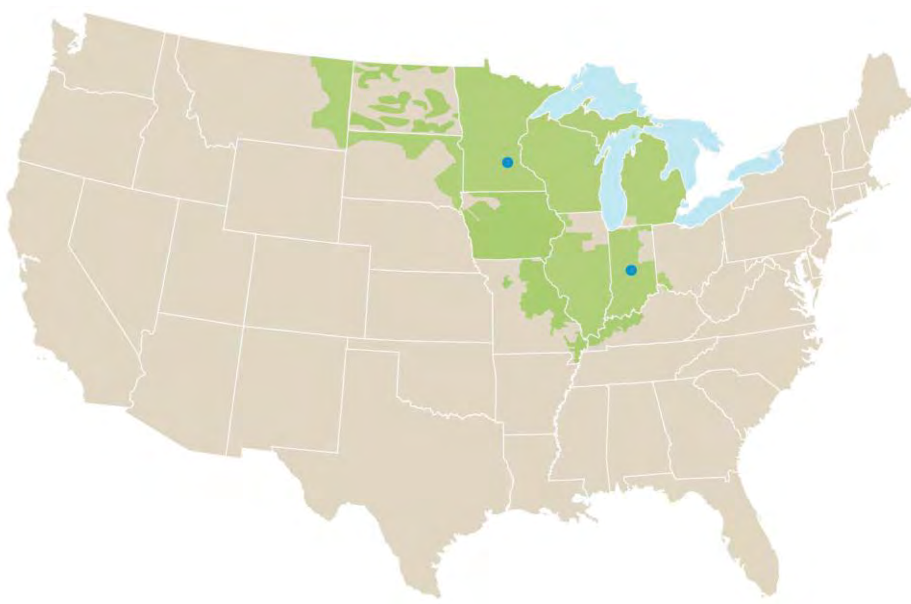
2.0 REVIEW OF CURRENT RPU POWER SUPPLY CONDITIONS

This part of the report discusses the assumptions for several key variables used in the analysis. The current conditions of RPU with respect to its load forecast and the resources it uses to meet its capacity and energy obligations are also discussed. In addition, it also provides a discussion of the MISO market and how it has matured from its development as an energy market in 2005. A review of the impacts of the RPU investment in the CapX transmission upgrades in the Rochester area is also included.

2.1 MISO MARKET

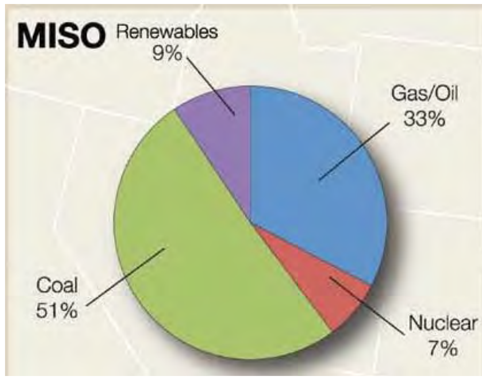
The MISO initiated its energy market in 2005, at about the time of the issuance of the initial Infrastructure Plan. The MISO market is made up of numerous utilities operating in the 11 states shown in Figure 2-1.

Figure 2-1 MISO Market Area



The MISO market has a peak load of approximately 98,000MW. It has resources of approximately 131,000 with which to meet this load demand. In addition to these dispatchable resources, MISO has over 7000MW of wind generation in its market. The mix of resources within MISO is shown in Figure 2-2.

Figure 2-2 MISO Resource Mix

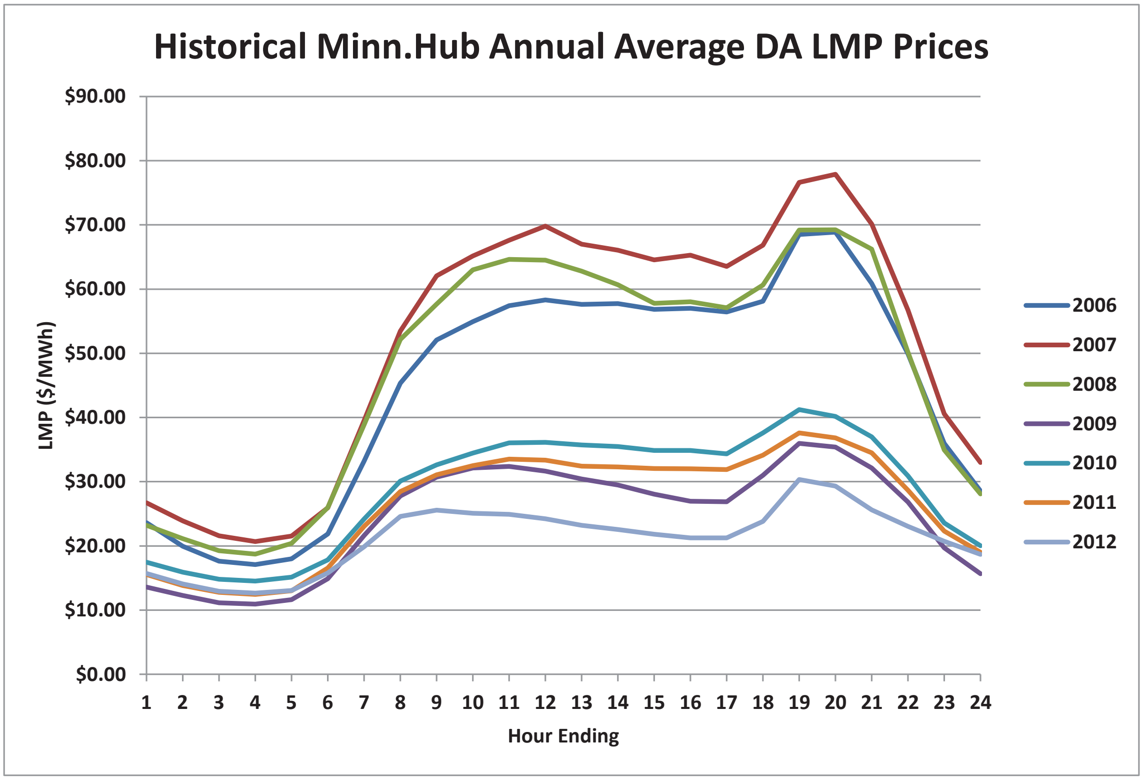


This market allows utilities to operate as they traditionally have and dispatch units they control to satisfy their load or to sell energy from their generation resources into the market and to purchase energy to meet their load requirements from the market. These purchase and sale transactions are performed on a daily basis. Over time, utilities have transitioned to selling generation into the market and procuring energy from the market. Load serving utilities have two basic obligations in the MISO market. The first is to meet the capacity requirements for peak load demand plus reserve margin. The second is to be able to satisfy the energy requirements of its customers.

Over the past several years, the market has matured and evolved in its business practices and standards for utilities. As a participant in the MISO market, RPU is subject to the business practices established by MISO and the MISO tariffs. One of these requirements is to maintain capacity reserves above its peak load obligations. The MISO currently is modifying the approach to determining the amount of reserves required by a utility by applying more severe availability assessments against generating units. This often reduces the accredited capacity considered by MISO for the unit below the nameplate capacity of the resource. At the same time, MISO is reducing the amount of reserve margin needed since uncertainty of the resource availability is reduced.

Utilities have become more accustomed to the market operations. It is common for utilities today to acquire all of their energy from the market and sell energy from their resources into the market when it is accepted for dispatch. In essence, all of the electrical energy RPU distributes above CROD is acquired from the MISO market. The cost for this energy has been affected significantly from the initial operation of the market. The past few years have seen prices decline significantly from the peak year of 2007. Figure 2-3 provides annual averages of hourly locational marginal pricing for day ahead energy at the Minnesota Hub for several years.

Figure 2-3 MISO Average LMPs
Minnesota Hub



Note: 2012 pricing is through Q1

The decline in pricing is due to several factors including:

- Economic downturn
- Mild weather
- Significant addition of wind resources
- Low pricing of natural gas

Many utilities are able to take advantage of this pricing condition and acquire energy from the market much more economically than they could from operating generating assets they own. This has led many utilities to adopt a strategy of contracting for or installing low capital cost assets to meet the capacity obligations for load and reserves. They then buy energy from the market at a more economical average cost than they could if they were to run the resources. When possible, energy is sold from the resource into the market and this revenue is used to reduce the average power cost of the utility. Due to the attractive pricing in the MISO market, many small to medium sized utilities such as Rochester are able to purchase energy at pricing well below their ability to generate it from their resources.

2.2 MAJOR ASSUMPTIONS FOR RESOURCE ANALYSIS

The following is a discussion of the major assumptions developed to analyze the future resource requirements of RPU. A complete set of assumptions is provided in Appendix A.

2.2.1 General Assumptions

The analysis began with the development of the baseline assumptions and constraints as applicable for RPU. The following general assumptions are applicable to the analysis:

- The study period covers the years 2015 through 2044.
- The hourly load used in previous studies was used and adjusted based on load growth projections.
- The interest rate for RPU for financing terms was 4.5 percent, with longer term resources financed over 30 years, and shorter term resources financed over 20 years.

2.2.2 Load Forecast

The load forecast was based on a recent SMMPA projection for RPU demand and energy requirements to 2030. The forecast is summarized on an annual basis over the study period in Table 2-1.

Table 2-1 RPU Demand and Energy Forecast

Year	Load (MW)	Energy (GWh)	Year	Load (MW)	Energy (GWh)
2015	326.9	1,631	2030	432.0	2,405
2016	333.3	1,676	2031	440.3	2,452
2017	339.6	1,715	2032	448.7	2,499
2018	345.9	1,759	2033	457.3	2,547
2019	352.2	1,803	2034	466.1	2,595
2020	358.5	1,856	2035	475.1	2,645
2021	364.8	1,899	2036	484.2	2,696
2022	371.1	1,948	2037	493.5	2,748
2023	378.2	1,999	2038	502.9	2,800
2024	385.5	2,058	2039	512.6	2,854
2025	392.9	2,108	2040	522.4	2,909
2026	400.4	2,164	2041	532.4	2,965
2027	408.1	2,222	2042	542.6	3,021
2028	415.9	2,286	2043	553.0	3,079
2029	423.9	2,343	2044	563.6	3,138

RPU's load forecast continues to be significantly below the initial forecast used in the 2005 Infrastructure Plan. The forecast used in this update is based on recent SMMPA projections. The adjusted forecast can be attributed to many factors including increased DSM programs and end-user efficiency. Therefore, it is inherently assumed in the forecast that the aggressive DSM reviewed in the initial Infrastructure Plan is capturing sufficient demand and energy to result in the SMMPA revised forecast. Table 2-2 provides the estimated savings and cost of capturing the DSM energy and demand reductions.

Table 2-2 RPU Historical DSM Savings and Costs 2002-2011

Year	Total kW Savings	Total kWh Savings	Total CIP Dollars Spent	$/kW
2002	4,743	7,562,201	$ 1,115,327	$ 235.15
2003	5,956	7,859,697	$ 1,327,321	$ 222.84
2004	7,189	9,827,569	$ 1,167,760	$ 162.44
2005	4,399	7,693,788	$ 1,213,517	$ 275.86
2006	2,210	10,457,152	$ 1,377,074	$ 623.00
2007	4,439	15,819,295	$ 1,995,606	$ 449.56
2008	4,332	13,665,636	$ 1,698,407	$ 392.03
2009	5,125	16,805,464	$ 2,303,375	$ 449.45
2010	5,339	19,126,719	$ 3,088,665	$ 578.51
2011	4,792	20,420,120	$ 2,943,028	$ 614.10
			Average	***$ 400.29***

Load forecast projections beyond 2030 were based on the average growth rate over the previous five years.

2.2.3 RPU Resources

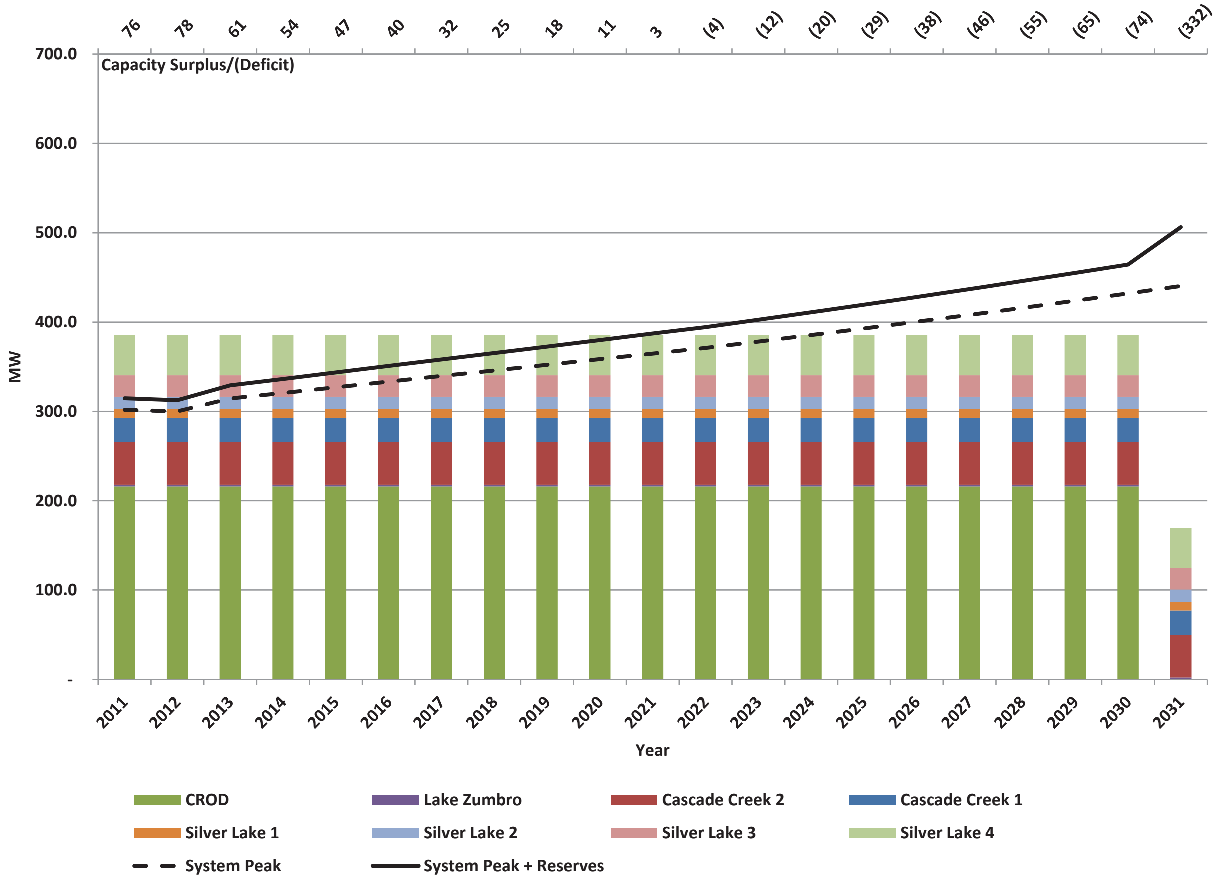
RPU has a number of resources to meet its capacity reserve margin requirements and renewable energy objectives. These include a diverse mix of coal, gas and hydro-electric generating units. RPU meets a significant amount of its power supply obligations through its contract with SMMPA, which currently runs through 2030. High level assumptions about the units and their operating parameters can be found in Appendix A. The units owned and operated by RPU are identified in Table 2-3.

Table 2-3 RPU Resources

Plant Name	Fuel	Commercial Operation Date	Max Operating Summer Capacity (MW)
Cascade Creek 1	Gas	6/1/1975	27.0
Cascade Creek 2	Gas	4/1/2002	48.0
CROD	N/A	N/A	216.0
Lake Zumbro	N/A	11/1/1984	2.0
OWEF (Energy only resource)	N/A	8/1/1970	5.0
Silver Lake 1	Gas	8/1/1948	9.5
Silver Lake 2	Gas	12/1/1953	14.0
Silver Lake 3	Gas	11/1/1962	24.0
Silver Lake 4	Coal	12/1/1969	45.0
IBM		10/1/2005	3.6

A balance of loads and resources (BLR) based on the load forecast and resources that RPU will have available to meet its obligations are shown in Figures 2-4. The reserve margin is shown based RPU maintaining a margin of 15 percent for its load above CROD and using the Max Summer ratings for the units.

Figure 2-4 RPU Balance of Loads and Resources



As shown in the previous figure, RPU does not become capacity deficit until approximately 2021 with the current resource mix. The expiration of the CROD in 2030 will create another large point of power supply deficit.

RPU has entered into various contracts with area entities for capacity and energy from the Silver Lake Power Plant. The Minnesota Municipal Power Association (MMPA) and the Southern Minnesota Municipal Power Association (SMMPA) have contracted for capacity and associated as scheduled energy from the facility. The SMMPA contract terminates in 2013 and the MMPA contract terminates in late 2015.

In addition to these contracts, RPU has a steam contract with the Mayo Clinic. RPU provides Mayo with up to 50,000 pounds per hour of steam from one of the steam units. As it was originally envisioned, the operation of the SLP on coal would allow the extraction of this steam for Mayo at a benefit for both parties. Currently, the reduced hours of operation of the SLP units in the MISO market have shifted the unit operation to a gas-fired operation of a small boiler to satisfy the contract. The earliest date for termination of this contract is 2015.

RPU provides energy to meet its energy obligations from the MISO market and the SMMPA contract. The accounting of this energy is provided through the MISO settlement process and the contract with SMMPA. The CROD with SMMPA is set to terminate in 2030. This contract requires RPU to purchase from SMMPA all of the retail energy it distributes at or below a rate of 216MW per hour.

2.2.4 New Resources

The capacity and energy needs of RPU are projected to potentially increase substantially over the study period. Two approaches could be used by Strategist to satisfy the capacity and energy obligations. These could be satisfied either from resources owned by RPU or contracted for through the market. The current EPA regulations have removed a new coal fired power plant from consideration as a new resource. Therefore, gas-fired and renewable resources are the only realistic resource options that RPU could construct.

When owned resources were not available or economical, a contract for market capacity from an accredited resource was used to maintain reserve margins throughout the study period. Market capacity resources are modeled as temporary supply resources, expiring at the end of each year. Table 2-4 summarizes the new resource and corresponding capacity levels populated in the Strategist model as potential new resource alternatives for meeting RPU's future capacity and energy requirements. Further operating and cost assumptions for the new resources can be found in Appendix A.

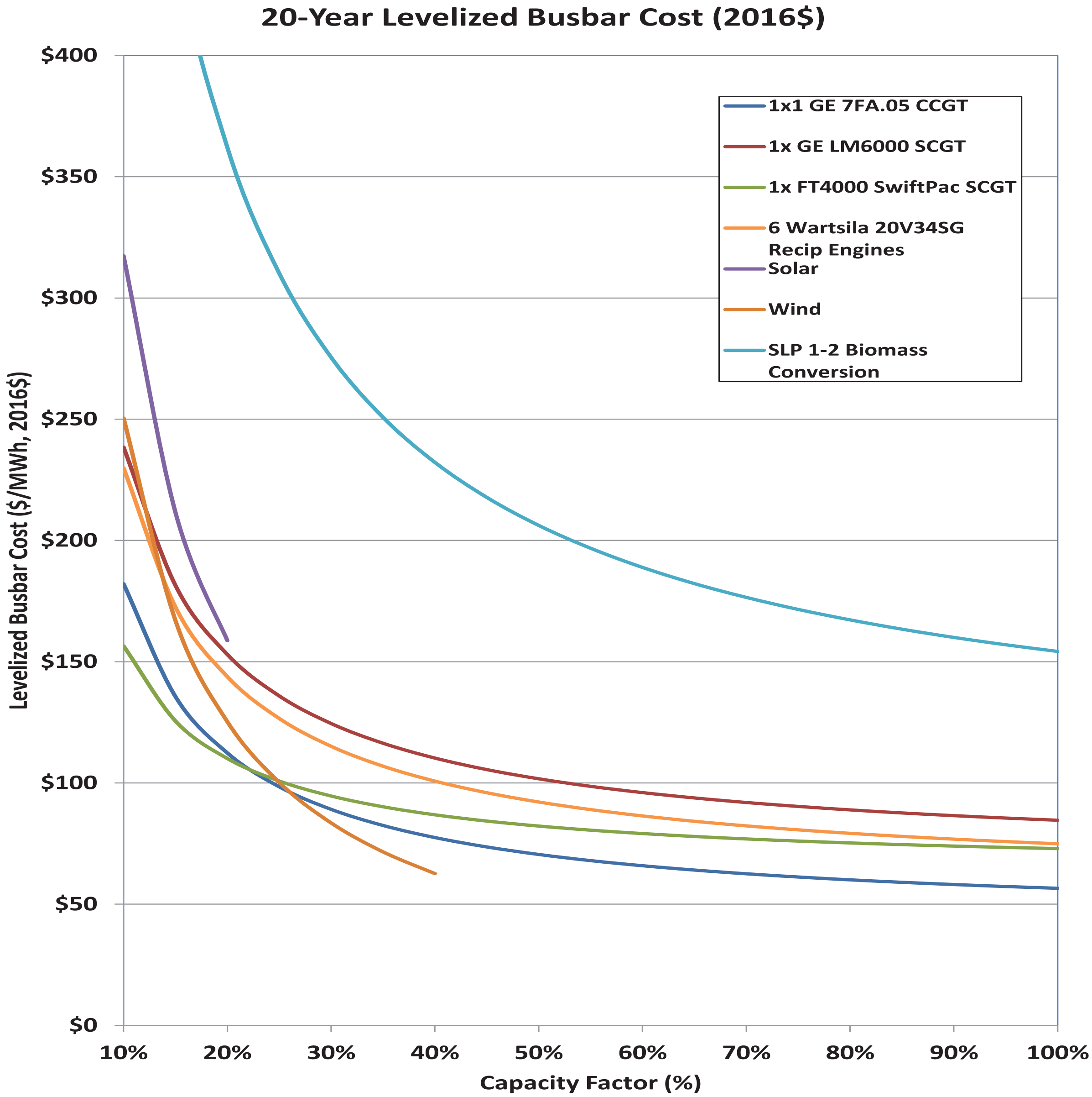
Table 2-4 New Resource Options Considered

Resource Option	Min. Project Cap. (MW)	Capital Cost (COD$/kW)	Earliest In-Service Yr	Fixed O&M (COD$/kW-yr)	Var. O&M (COD$/MWh)
1x1 GE 7FA.05 CCGT	288.2	$1,530	2016	$16.45	$3.09
1x GE LM6000 SCGT	45.3	$1,747	2016	$27.26	$10.60
1x FT4000 SwiftPac SCGT	125	$1,035	2016	$10.04	$8.06
6x Wartsila 20V34SG Recip Engines	54.6	$1,717	2016	$29.84	$6.73
Solar	1	$2,942	2016	$29.42	-
Wind	25	$2,068	2016	$39.60	-
SLP 1-2 Biomass Conversion	11.5	$3,913	2016	$101.83	$6.22

Note: Solar costs include current federal tax and RPU credits
Wind pricing is for a utility grade wind project

The capital, fixed and variable operating and maintenance costs for each of the above resources were modeled using levelized bus bar cost analysis. The results of this analysis are summarized in Figure 2-5.

Figure 2-5 Levelized Bus Bar Cost Analysis for Resource Options



Based on the levelized analysis summarized in Figure 2-2, the biomass option and solar options were not considered economically attractive as firm capacity resources. Also, although wind resources are economically attractive, they do not provide the firm capacity required to meet RPU's capacity obligations. Therefore, for purposes of this analysis, only the gas based options were considered.

2.3 FUEL CONSIDERATIONS/FORECASTS

The analysis utilized gas, coal, and spot market pricing to help determine production costs for each of the various supply alternatives considered and for the existing units. The following paragraphs discuss each of the various fuel forecasts used in this analysis.

2.3.1 Coal

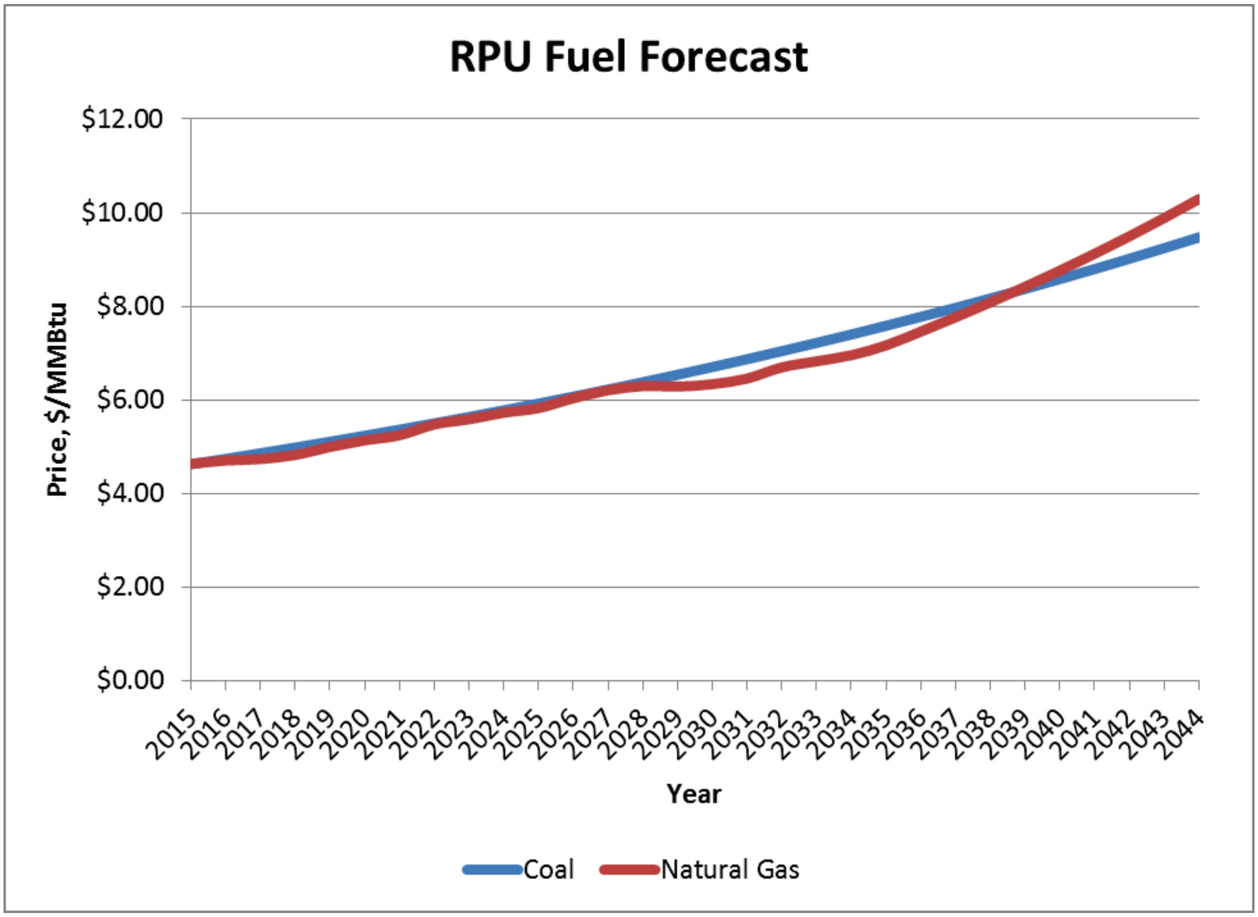
The cost of coal for the Silver Lake Power Plant was provided by RPU and is summarized in Figure 2-6. The current fuel is being delivered to the plant under a contract with Dairyland Power Cooperative. The contract currently calls for procuring 40,000 tons. Under the contract, 30,000 tons have been delivered and 10,000 tons remain to be delivered. The coal forecast used in the original Infrastructure Study was estimated to cost $2.35 per mmBtu as compared to the actual cost of $4.62 per mmBtu in the Dairyland contract.

2.3.2 Natural Gas

The pricing for natural gas has seen a significant decline over the past several years as the discoveries from drilling with hydraulic fracturing for both oil and gas have rapidly expanded the known reserves. Burns & McDonnell developed a natural gas forecast for RPU using the Energy Information Agency’s forecast with adjustments made in the short term based on the NYMEX futures for natural gas and location from the Henry Hub pricing point.

The forecast for natural gas used in the study is shown in Figure 2-6. This forecast was used as the base natural gas price for all resource alternatives that required the use of natural gas as a fuel. The volatility of natural gas will lead to certain years having low pricing and some years having high prices due to supply and demand impacts around the world. The current market price for natural gas is lower than forecast due to the significant supply of natural gas as compared to its consumption. As a comparison, the previous EIA natural gas forecast used in the Study predicted gas to cost $7.93 per mmBtu in 2016 instead of the currently forecast $4.71 per mmBtu.

Figure 2-6 Natural Gas and SLP Coal Forecast



2.3.3 MISO Market

Capacity in the MISO market is required for utilities to meet their reserve margin obligations. Although the MISO market does not include a specific market for capacity as it does for energy, capacity is traded on a bilateral basis between parties. Utilities can contract from a variety of parties to meet their capacity obligations. In the current MISO capacity construct, this capacity must be sourced from a specific generating resource capable of supplying the capacity stated in the contract. The current price for this capacity is significantly below the cost of a newly constructed resource.

The spot market energy price forecast was developed using the hourly day-ahead LMP pricing of the SMP.RPU node in MISO from January through December 2011. On-peak energy prices for 2015 and beyond were projected using the same underlying annual escalation as the EIA natural gas forecast and off-peak energy prices were projected using the same underlying annual real escalation as utility coal as provided by the EIA throughout the study period.

The MISO market operates primarily as an energy market, with a secondary market in ancillary services. Utilities that participate in the market, such as RPU, purchase energy at the locational marginal price of their respective load nodes. Utilities are able to purchase energy from the market at their LMPs or to schedule energy from a bilateral contract or their own resources. They can sell energy that they do not use from their resources in to the market. Revenues from these sales are established from the LMP of the generator node. As the market has matured since 2005, the majority of market participants sells energy to the market when their resource costs clear the market and purchases all of their energy from the market.

RPU has been operating in this manner for several years. It bids the Cascade Creek and Silver Lake units in to the energy market and acquires energy for load above CROD from the market. Based on the market LMP pricing and unit characteristics, the Cascade Creek Unit 2 operates more frequently than the other units. Table 2-5 provides a summary of the hours each of the units operated in 2011. As a comparison, to see the impact of MISO pricing on the facilities' dispatch, the hours of operation in 2005 are also shown.

Table 2-5 Hours of Operation of Cascade Creek and Silver Lake Units 2011 and 2005

2011	SLP4 Hours	SLP3 Hours	CCRK1 Hours	CCRK2 Hours	SLP1 Hours	SLP2 Hours
Jan	0	0	0	0	0	0
Feb	0	0	0	2	0	0
Mar	0	0	0	6	0	0
Apr	0	0	0	2	0	0
May	0	0	4	0	0	0
Jun	32	5	0	15	30	29
Jul	26	56	13	54	7	66
Aug	0	0	0	4	0	0
Sep	0	0	0	31	6	0
Oct	0	0	0	7	0	0
Nov	0	0	0	6	0	0
Dec	0	0	0	10	0	0
Total	58	61	17	137	43	95
2005						
Jan	586	580	0	10	424	332
Feb	483	527	1	0	462	310
Mar	535	457	0	3	396	0
Apr	17	309	0	15	82	0
May	0	398	2	11	14	21
Jun	612	402	19	90	344	277
Jul	631	0	19	139	577	497
Aug	427	0	5	77	586	477
Sep	452	0	7	8	448	223
Oct	396	360	0	7	242	66
Nov	396	489	0	4	434	207
Dec	486	597	77	20	603	503
Total	5,021	4,119	130	384	4,612	2,913

As seen from the above table, the hours of operation of the SLP units has changed dramatically over the period from the original Study to today. The cost structure of the SLP units with regard to other units in the market is reducing the attractiveness of these units in the market. In addition, the time it takes to start these steam units is several hours whereas the time it takes to start the combustion turbines is several minutes. This allows the combustion turbines to be in and out of the market quickly when the LMP is attractive. The operating characteristics of the steam units at SLP are less flexible than the combustion turbines. Since LMPs may be high for only a few hours, this flexibility is important to maximize revenues in the market.

2.4 TRANSMISSION IMPROVEMENTS

Utilities in Minnesota have been reviewing upgrades to the transmission system for several years. These improvements have been collected into a transmission plan called the CapX. Specifically for RPU, improvements to the 161kV lines around RPU will allow significant reliability improvements to the transmission grid and allow additional reliable access to the market.

The information in Table 2-6 provides an indication of the increase in the first contingency import capability with the addition of the 161kV lines in North Rochester. This limit is established by reviewing the limitations caused by outages of transmission elements in the area that affect the import limit. For this assessment, the most limiting outage involved the loss of the North Rochester to Northern Hill 161kV line. The results indicate that the transmission system will be over twice as reliable, allowing RPU to rely more on external resources.

Table 2-6 First Contingency Import Capability Results Due to CapX Improvements

Operating Study-No RPU Units on line

Case	RPU Import Limit
Existing System	148 MW
Add North Rochester-Northern Hills 161 kV	292 MW
Add North Rochester-Northern Hills 161 kV + North Rochester-Chester 161 kV	372 MW

Operating Study - CT 2 On-line at 49.9 MW

Case	RPU Import Limit
Existing System	148 MW
Add North Rochester-Northern Hills 161 kV	357 MW
Add North Rochester-Northern Hills 161 kV + North Rochester-Chester 161 kV	438 MW

Past studies for RPU have always had to consider the limited import capability that RPU had for outside power. With the existing transmission system, a portion of RPU generation had to be dispatched to allow the existing system capability of 148MW to be provided during a contingency. If the contingency occurred during a peak load time, RPU would be required to maintain sufficient generation to cover its load above this 148MW limitation or shed load. At the current peak load of approximately 300MW, all of the RPU generation at Silver Lake and Cascade Creek would be required to operate unless load was shed. Once the CapX area transmission improvements are completed, RPU can import up to 372MW with no generation operating and 438MW with the Cascade Creek CT2 operating. RPU is not projected to be at this peak demand level until approximately 2030.

The CapX improvements are scheduled to be in service by 2016.

2.5 CONCLUSIONS

Based on the review of RPU's current conditions and the changes that have occurred in major assumptions since the Infrastructure Study, Burns & McDonnell provides the following conclusions and observations:

1. RPU's load projections are such that resource deficits will occur in approximately 2021 with the current resources and load forecast. RPU has several options to obtain capacity to fill this deficit at reasonable cost.

2. The current and projected pricing for fossil fuels associated with power production is shifting production of electricity from coal as a fuel to natural gas.

3. As a participant in the MISO market, RPU is responsible to provide sufficient capacity to meet its capacity for load plus reserves obligations in accordance with MISO regulations. It is able to acquire the energy for its load above CROD from the MISO market.

4. The development of the MISO market has provided an opportunity for small and medium sized utilities to take advantage of attractive pricing for capacity and energy procured from the market.

5. The energy pricing in the MISO market has decreased significantly from its peak of 2007. This pricing has dramatically reduced the attractiveness of the units at the SLP to the MISO market, which is reflected in the change in their run times between 2005 and 2011.

6. The diversity of fuel sources in the MISO market includes nuclear, hydro, wind, coal and natural gas. This diversity is greater than what utilities, such as RPU, could typically maintain on their own.

7. The investment that RPU is making in the CapX transmission upgrade projects is providing increased, firm access, to the area market. This reduces the need to maintain the level of generation relative to load that RPU has deemed necessary in the past to maintain the high level of reliability its customers require.

* * * * *

SECTION 3.0

IMPACT OF EPA ACTIONS ON SILVER LAKE POWER PLANT

3.0 IMPACTS OF EPA REGULATIONS ON SILVER LAKE POWER PLANT

RPU owns and operates the Silver Lake Power Plant, located adjacent to downtown Rochester, MN. This plant consists of four units that are capable of operating on both coal and natural gas. The units have been added over the time period of 1948 to 1969. The units are used to meet RPU’s capacity obligations with the MISO market and its contracts with MMPA, SMMPA and the Mayo Clinic. As discussed in Section 2, the operation of the units has declined significantly from the time of the initial Study.

3.1 SLP EMISSION CONTROL UPGRADES

At the time of the initial Study, RPU was evaluating various upgrades to the SLP in order to meet a settlement agreement with the Minnesota Pollution Control Agency (MPCA) and the Minnesota Center for Environmental Advocacy (MCEA). This agreement was developed as a result of modifying the SLP to provide steam to the Mayo Clinic. As required by the agreement with the MPCA/MCEA new emission controls were installed and placed in service in 2009. The upgraded emission controls allowed the SLP Unit 4 to operate on coal and achieve compliance with all current and anticipated environmental regulations. These upgrades were seen as necessary in order to keep the SLP unit 4 as a viable unit to meet contractual obligations and to provide backup power supply to the city due to the transmission limitations. It was also considered that over time, the SLP units would also be used to provide energy to meet RPU load as the load grew above the CROD.

3.2 CURRENT EPA ACTIONS WITH UTILITY INDUSTRY

The EPA has begun to finalize regulations that have been pending under the Clean Air Act, the Clean Water Act and the Resource Conservation and Recovery Act that affect operations of existing and construction of new power plants. Units fired by coal are the most significantly affected. This section of the report describes the environmental regulations that could impact the RPU units in the future. General background information on each rule and its current status are discussed in Appendix B. Table 3-1 was developed by RPU and contains recent and imminent environmental regulations that affect RPU’s generating resources and RPU management’s approach to comply with the regulations.

Table 3-1 Current and Projected EPA Environmental Regulations Affecting Generating Units

	Regulatory Action	Add link	Lead Agency	Description	Proposal Date	Projected/Actual Date for Final Agency Action	Effect date of Rule	Applicable to New (N), Existing (E) or Modified (M) Facilities?	Facility/Unit Affected	RPU Compliance Date	RPU Compliance Approach
NAAQS Criteria Pollutants (e.g. SO2, Ozone, PM)	Cross State Air Pollution Rule (CSAPR)		EPA	Proposed cap & trade rule to replace CATR and CAIR. Requires significant reductions in SO2 and NOx emissions in an effort to reduce fine PM and ozone in down-wind locations. Final rule has been stayed by federal court.	08/02/2010	07/06/2011	January 2012; rule stayed 12/30/2011	N, E	SLP - U4	01/01/2012	U4 allowance allocation will allow operation on coal at 40% capacity factor
									CCCT - GT2	01/01/2012	Adequate allowances for normal operation
	NO2 National Ambient Air Quality Standard (NAAQS)	*	EPA	EPA finalized a new 1-hour NO2 standard at the level of 100 ppb. (EPA-HQ-OAR-2006-0922). Modeling will determine impact on units.		02/09/2010	02/09/2013	N, E	SLP - All	June 2017	Compliance modeled with U1-3 on gas and U4 on coal.
									CCCT - All	June 2017	Minor changes may be required.
	SO2 NAAQS	*	EPA	EPA finalized a new 1-hour SO2 standard at the level of 75 ppb. EPA also revoked the existing primary 24-hour and Annual standards. (EPA-HQ-OAR-2007-0352). Modeling will determine impact on units.		06/02/2010	06/02/2013	N, E	SLP - All	June 2017	Compliance modeled with U1-3 on gas and U4 on coal.
									CCCT - All	June 2017	Compliance modeled.
Greenhouse Gases	GHG Mandatory Reporting Rule		EPA	Rule requireing stationary fuel combustion sources that emit more than 25,000 tons of carbon dioxide equivalent per year to determine and report their GHG emissions.		10/30/2009	1/1/2010	N, E	All	1/1/2010	Currently in compliance
	PSD/Title V GHG Tailoring Rule		EPA	Rule tailoring criteria that subjects sources to GHG permitting requirements		05/13/2010	01/02/2011	N, M		Only if a Modification occurs	Currently in compliance
	GHG NSPS for Existing Plants		EPA	GHG emission standards for existing (unmodified) power plants - EPA has stated that no standards for existing units will be set at this time.	NPRM 9/30/2011	??		E			Currently not applicable
NESHAP Hazardous Air Pollutants (e.g. mercury, acid gases)	NESHAP RICE MACT Rule		EPA	Revisions address previously unregulated units including existing RICE at area sources (all sizes), existing RICE < 500 hp at major sources (constructed before 6/12/06), existing non-emergency CI RICE > 500 hp at major sources (constructed before 12/19/02)		03/03/2010	05/03/2013	N, E	IBM/EU001, EU002	May 3,2013	Minor changes may be required.
									CCCT	May 3,2013	Minor changes may be required.
									SC/Emergency Gen	May 3, 2010	Currently in compliance
	NESHAP IB MACT Rule		EPA	EPA promulgated new rules for emissions standards and compliance requirements for Industrial boilers. (EPA-HQ-OAR-2002-0058). This rule is stayed until revised rules published.	12/23/2011	August 2012	60 days after publ in FR (Aug 2012??)	N, E	SLP/EU001, EU002, EU003, EU005	3 years + 60 days after publ in FR (Aug 2015)	U1-3 must cease burning coal.
	NESHAP EGU MACT Rule	*	EPA	EPA to set Maximum Available Control Technology (MACT) standard for all coal-fired power plant mercury emissions; and a range of other HAPs emitted by coal and oil-fired power plants. (EPA-HQ-OAR-2009-0234)	5/3/2011	2/16/2012	4/16/2012	N, E	SLP EU004	4/16/2015	Compliance can be achieved with minor changes.
CWA	Waste Water Discharge Regulations under CWA		EPA	Regulation of waste water discharges from thermal generating units. (EPA-HQ-OW-2009-0819)	NPRM 7/2012	Late 2012		N, E			No compliance problems anticipated.
	CWA Section 316(b)		EPA	EPA rule to replace remanded rule for regulating cooling water intake structures at existing facilities. (EPA-HQ-OW-2008-0667)	NPRM 4/2011	2012		E			To be determined.
Ash	Coal Combustion Residuals		EPA	RCRA rules on disposal of coal combustion wastes – possible treatment as hazardous waste. Comment Period closed on 11/19/10	NPRM 6/21/2010	Unkown		N, E			To be determined.
	Fugitive Emission Rule		EPA	Treatment of Fugitive Emissions in the New Source Review Permitting Program. The administrative stay of provisions in 40 CFR 51.165, 51.166, Appendix S to part 51, and 40 CFR 52.21 (75 FR 16012)		10/4/12					To be determined.
	EPA 114 Request		EPA	Potential NSR enforcement action							To be determined.

3.3 EPA ACTIONS WITH RPU

In November 2010, the federal EPA notified RPU of a potential violation of the Clean Air Act under the Prevention of Significant Deterioration/New Source Review regulations. This process was initiated through a Section 114 Information Request delivered to RPU on November 18, 2010. The EPA and RPU discussed this issue during December 2010. RPU submitted a proposal for settlement to EPA Region 5 on January 21, 2011. On June 3, 2011, the EPA provided its Settlement Counter Proposal to RPU.

3.4 REVIEW OF EPA ACTIONS

3.4.1 Industry Impacts

The effect of the EPA's new regulations is to essentially eliminate the construction of any new coal fired power plants in the United States. This effect is primarily due to the difficulty of any manufacturer of the emission controls equipment to guarantee the emission levels required. This in effect makes the plants unable to be financed.

For existing units, considerable analysis is being performed on units to either retire them from service, retrofit them to comply with the existing and anticipated EPA regulations or to repurpose the facility into a gas-fired unit. It is expected that the EPA actions will result in the retirement of approximately 40,000MW or more of existing coal-fired units. Many utilities in Minnesota are reviewing the long term viability of their coal-fired units. Recent reports by generator owners to the Energy Information Agency of the DOE indicate that 27GW of coal-fired capacity is being planned for retirement. Table 3-2 provides a summary of information about the retirements from 2009 to 2011 and planned units from 2012 to 2015.

Table 3-2 Historical and Announced Coal-fired Unit Retirements 2009-2015

	Existing Coal Capacity[1]	Reported coal generator retirements						
		Historical			Planned			
		2009	2010	2011	2012	2013	2014	2015
Total Net Summer Capacity (MW)	317,469	529	1,528	2,517	8,890	2,098	4,715	9,865
Number Of Units	1,387	12	35	31	57	14	34	61
Average Net Summer Capacity (MW)	228	44	44	81	156	150	139	162
Average Tested Heat Rate (Btu/kWh)	11,281	12,200	12,879	10,714	10,897	13,922	11,067	10,659
Average Age at Retirement	N/A	50	54	62	56	55	57	57

[1] Reflects all coal units that existed at year-end 2011.

Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Note: Data for 2009 through 2011 represent actual retirements. Data for 2012 through 2015 represent planned retirements, as reported to EIA. Data for 2011 through 2015 are early-release data and not fully vetted. Capacity values represent net summer capacity.

3.4.2 RPU Impacts

3.4.2.1 General EPA Regulations

Detailed air dispersion modeling and applicability assessments were performed by RPU to assess how the EPA actions could affect the operation of the SLP units. Based on RPU's interpretation of the regulations and the results of the modeling, the following results were developed for SLP:

- Regulations can be met when operating SLP Units 1, 2 and 3 on natural gas. Unit 4 can be operated to meet regulations on coal, however performance optimization of the existing emission control systems would be required.
- SO_2 and NOx allowance allocations for SLP Unit 4 are adequate for operation at an approximate 40% capacity factor.
- A restrictive coal sulfur specification would be required.

3.4.2.2 EPA NSR Enforcement Action

In comparing the EPA settlement counter offer, the emission rates between the EPA regulations in affect or being promulgated were compared to the settlement offer. The comparison of the major emissions indicated that, to meet the limits in the settlement counter offer, additional controls would be needed at the SLP. In addition to the limits being more restrictive under the EPA proposed NSR settlement counter offer, the time frame for compliance begins in 2012 versus the 2012 to 2017 time frame for the various EPA regulations.

A preliminary assessment of the cost of continuing to operate the SLP Unit 3 and Unit 4 on the current coal was developed by Burns & McDonnell. The assessment indicated that, in all likelihood, the equipment summarized in Table 3-3 would be needed in order to operate with any level of assurance to meet the limits in the EPA proposed NSR settlement counter offer over the expected loading ranges for SLP Units 3 and 4 using the existing coal burned at the plant.

Table 3-3 Probable Equipment Requirements for EPA NSR Enforcement Action Settlement Offer

SLP Unit	Technology	Estimated Budget
Unit 3	Semi-dry scrubber and baghouse	$17,500,000
	SCR	$14,000,000
Unit 4	Wet FGD	$40,000,000
	SCR	$19,000,000
Total		$90,500,000

In addition to these fixed investment costs, there would be impacts to unit heat rates and operating and maintenance costs.

Another consideration in the approaches to comply with the EPA proposed NSR settlement counter offer would be to switch the SLP to operate on natural gas. The city of Rochester is served locally by the local distribution company (LDC) Minnesota Energy Resources, Co (MERC). MERC receives gas from the area interstate pipeline network at a high pressure. The pressure is reduced and distributed through a network of pipes within Rochester to retail consumers.

The LDC is served by the interstate pipeline managed by Northern Natural Gas (NNG). The NNG system connects to the LDC system at two town border stations (TBS). One TBS is located to the west of Rochester near the West Side substation. The other TBS is located south of Rochester in the area of the intersection of highway 52 and 11th Ave Southeast.

In consideration of switching the SLP to operate totally on natural gas, the delivery capacity of the interstate and LDC networks has to be considered. For adequate service, the pressure of the gas in the lines must be maintained as the flow volumes increase due to the SLP demand. This condition has to be satisfied for the maximum conditions, which for Rochester, occur during the winter heating season.

Inquiries were made to NNG and MERC as to the capability of serving the SLP with sufficient gas to operate the units on natural gas. The gas consumption required for RPU if all of the units were switched to natural gas is summarized in Table 3-4.

Table 3-4 Estimated Gas Requirements RPU Units

	Silver Lake				Cascade Creek	
	Unit #4	Unit #3	Unit #2	Unit #1	GT-1	GT-2
dekatherms/hr	640	335	192	144	420	540
dekatherms/day	15,360	8,026	4,608	3,456	10,000	12,960
MW output	56	24.9	14.4	9.69	49.9	30

The total additional load to the gas system due to SLP could be approximately 31,500 dekatherms per day. NNG indicated that significant branch line improvements would be needed to satisfy the SLP demand and the TBS facilities would need to be rebuilt. Very preliminary conceptual costs for these upgrades were provided to be in excess of $40,000,000.

Discussions with MERC indicate that there is inadequate line capacity in the downtown Rochester area to satisfy the current winter gas demand and operate the SLP units on natural gas. The local distribution system from the TBS to the SLP would need to be upgraded. Costs for this upgrade have not been estimated.

In addition to the costs of these facility upgrades, RPU would have to purchase a portion of the natural gas on a “firm” basis. The quantity of gas that would have to be procured as firm is not known at this time. The quantity would be based on the amount needed to satisfy the MISO that sufficient capacity could be dispatched at the SLP with firm fuel supply to satisfy the requirement for the accredited capacity that RPU claims to satisfy its capacity obligation with the MISO. The current fuel supply for the SLP is firm in the sense that there is sufficient coal storage at the facility to satisfy this requirement. The MISO is just beginning to be concerned about this issue due to the amount of natural gas units being used to satisfy the capacity requirements. Current estimates to firm the natural gas purchase are approximately $14 per dekatherm per month. These costs would be in addition to the commodity gas price forecast provided in Part 2 of this report, which represent purchasing natural gas on a “non-firm” basis.

3.5 CONCLUSIONS

Based on the assessment of EPA actions on the utility industry in general and RPU specifically and a review of options to comply with the EPA actions, Burns & McDonnell has developed the following conclusions:

1. The EPA is aggressively targeting coal-fired electrical generating units with general industry regulations tightening the allowed emissions from the units. In addition, EPA is directly targeting

certain utilities with suspected violations of existing regulations under NSR of the Clean Air Act at certain coal-fired units and obtaining settlements with regards to requirements to reduce emissions from the affected coal-fired units.

2. The more onerous EPA action which affects RPU is complying with the proposed EPA NSR Enforcement Action settlement counter offer provided to RPU in June, 2011. In order for the SLP Units 3 and 4 to maintain the option to burn coal under the proposed settlement counter offer, further emission controls will be required on the units.
3. Preliminary conceptual capital cost estimates for additional equipment for the units to comply with the EPA NSR Enforcement Action settlement counter offer are significant. In addition, there will be impacts to the operating costs and characteristics of the units.
4. The option to convert the units to operate on natural gas will require significant natural gas infrastructure improvements on both the interstate pipeline system feeding the Rochester local distribution system and the local distribution system.
5. If the SLP units are converted to natural gas, it is expected that a portion of the gas supply will need to be procured on a firm basis to satisfy the RPU capacity obligation with the MISO.

* * * * *

SECTION 4.0

RESOURCE STRATEGY

4.0 RESOURCE STRATEGY

RPU has a need to address several issues associated with its electric resources. The most immediate is how to address the EPA NSR Enforcement Action issue and secondarily how to address expected capacity deficits anticipated to occur in the 2021 time frame. In order to assess options that might be beneficial to pursue with regards to these issues, Burns & McDonnell developed scenarios of various resource options that RPU could follow. This part of the report provides a summary of that analysis.

Various resource planning assumptions and scenarios were developed and analyzed using Ventyx's Strategist software to study the various futures considered viable for RPU. The Strategist model is a resource portfolio optimization model that allows an analysis of several different resources with a variety of characteristics to meet the load requirements and any other defined constraints over a finite period of time. The model develops potentially thousands of resource combinations based on the scenario-defined constraints, ranking these combinations by net present value (NPV) over the study period. This allows the selection of the lowest evaluated cost combination of resources, including optimal size and implementation schedules for new resources, based on the performance and construction costs provided. Scenarios were developed to analyze the various approaches which RPU could use to meet its obligations.

4.1 SCENARIO DEVELOPMENT

In the assessment of resource plans, it is common to consider various futures that could confront a utility. The comparison of the portfolios that are developed for the scenarios allows the utility to identify the qualitative and quantitative differences between the futures. The major difference between futures for RPU is associated with the future of the SLP. Essentially RPU would need to determine if additional investment in the facility to meet the recent EPA requirements is warranted based on its current and expected operation. The following paragraphs describe the two basic scenarios developed for this update to the Infrastructure Plan.

4.1.1 SLP in Service Scenario

Burns & McDonnell reviewed the approaches to meeting the RPU obligations associated with new EPA regulations at the SLP in order for the plant to remain in compliance. The more problematic issue concerns the proposed EPA NSR Enforcement Action settlement counter offer. There are significant capital costs estimated to be necessary for RPU to invest in the SLP in order to comply with the EPA's offer and retain the ability to operate SLP Units 3 and 4 on coal. As an alternate, RPU could consider switching the fuel for these units to natural gas. However, in order to maintain the ability to dispatch on any type of firm basis using natural gas, additional investment would be needed in the gas infrastructure on the interstate and local gas systems as discussed in Part 3. For purposes of this analysis, it was assumed that the capital investments identified in Part 3 to bring the units into compliance with the proposed EPA NSR Enforcement Action settlement counter offer were required.

4.1.2 SLP Retired Scenarios

As an alternate to investing in SLP, RPU could consider retiring the facility and obtaining capacity to meet its MISO capacity obligations for load and reserves from other sources. When considering the retirement options for SLP units, there are several combinations of units to retire and units to remain in service. The major difference between the options is the amount of fixed costs that would result from the units remaining in service.

The retirement scenario would subject RPU to capacity deficits earlier than in the scenario where SLP remains in service. Due to the existing contractual obligations that RPU has with the MMPA and Mayo Clinic, the earliest date in which the entire SLP could be retired would be December 31, 2015.

One retirement scenario considered was to retire the entire SLP facility in 2015. In this scenario, beginning in 2016, all of the fixed and variable maintenance costs would be taken off of the cost structure for the RPU resources. Staffing is assumed to be reduced to a level necessary to support just the combustion turbines at Cascade Creek, the IBM generator sets and the hydro facilities at Lake Zumbro.

A second retirement scenario would be to retire all of the units but Unit 4, which would be retrofitted to remain compliant using coal as a combustion fuel. This scenario would essentially require all of the existing staffing costs to remain, require the investment in the emission controls necessary to bring the unit into compliance with the proposed EPA NSR Enforcement Action settlement counter offer, and the ongoing fixed and variable operation and maintenance costs for the unit.

In either of the above scenarios, Units 1 and 2 could remain in service using natural gas as a combustion fuel with minimal change in the estimated revenue requirements. Maintaining these units in service for a period of time beyond 2016 may have benefit with regard to the Mayo Clinic steam contract and allow Mayo to better transition to an alternate steam source.

4.1.3 Resource Options

Due to the CapX investment, RPU is able to acquire considerably more capacity from the market to meet its obligations and not be as concerned about resources having to be located within RPU's service territory to provide energy in case of a line outage. For purposes of the planning scenarios, a limit of 75MW was placed on the amount of capacity that RPU would acquire from the market before a unit would be constructed by RPU. Market capacity was assumed to be priced at $2.50 per kW-month with a requirement to purchase the capacity on a 12 month basis. This is conservative due to the current market price and the ability that a utility has to just purchase seasonal capacity for its needs.

RPU constructed resource options were selected from the lower capital cost options identified in Part 2. These would include combustion turbines and reciprocating engines. All of the new dispatchable resources would be fired on natural gas as a primary fuel. It is anticipated that the smaller units would be able to be permitted with fuel oil as a backup fuel to allow purchase of gas on a non-firm basis. The resources would be added at the new site acquired on the north side of Rochester.

4.2 SCENARIO ANALYSIS

The scenarios were analyzed in Strategist with the market and owner constructed resource options made available. The results of the Strategist analysis are summarized in Table 4-1.

Table 4-1 Scenario Results Summary

Scenario	1		2		3
Plan Year	**Retire All SLP 2015**		**Retire SLP 1,2,3 2015**		**No Retirements**
2015					
2016	DEF(48)		DEF(4)		
2017	DEF(54)		DEF(10)		
2018	DEF(61)		DEF(17)		
2019	DEF(67)		DEF(24)		
2020	DEF(74)		DEF(30)		
2021	LM6000 DEF(35)		DEF(37)		
2022	DEF(42)		DEF(43)		DEF(4)
2023	DEF(49)		DEF(51)		DEF(11)
2024	DEF(57)		DEF(58)		DEF(19)
2025	DEF(64)		DEF(66)		DEF(26)
2026	DEF(72)		DEF(74)		DEF(34)
2027	LM6000 DEF(35)		LM6000 DEF(36)		DEF(42)
2028	DEF(43)		DEF(45)		DEF(50)
2029	DEF(51)		DEF(53)		DEF(59)
2030	DEF(60)		DEF(61)		DEF(67)
2031	7FA Combined Cycle		7FA Combined Cycle		7FA Combined Cycle
2039					DEF(4)
2040	DEF(7)		DEF(9)		DEF(15)
2041	DEF(18)		DEF(19)		DEF(25)
2042	DEF(28)		DEF(30)		DEF(36)
2043	DEF(39)		DEF(41)		DEF(46)
2044	DEF(50)		DEF(52)		DEF(57)
NPV UTILITY COST (@ 6.0%) PLANNING PERIOD ($000) *% DIFFERENCE*	With CROD $2,289,340 *0.00%*		With CROD $2,385,414 *4.20%*		With CROD $2,373,307 *3.67%*

Note: DEF is a capacity purchase from the market. The amount in () is the MW amount.

There are two basic cost considerations associated with the potential of Scenario 1 versus Scenario 2. The first is the avoided investment of approximately $90,500,000 in the emissions equipment to bring the SLP Units 3 and 4 into compliance with the proposed EPA NSR Enforcement Action settlement counter offer. The second is the avoided costs associated with the operation and maintenance costs of the SLP.

A review of the Strategist output (provided in Appendix C) for the cases with SLP operational indicate that Unit 4 would be dispatched at a capacity factor in the range of 4 to 7 percent over the period to 2030. In comparison, the Cascade Creek Unit 2 is dispatched at a capacity factor ranging from 5 to 19 percent over the same period. This indicates that the expected variable operating costs of a simple cycle combustion turbine are more attractive to the MISO market than the SLP units with the current assumptions for natural gas and coal. The annual costs associated with the futures are summarized in Table 4-2 for the years 2015 to 2024.

Table 4-2 Annual Costs 2015 – 2024

($000)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Scenario 1 - Retire All SLP 2015										
Fixed Costs-Total	$11,844	$6,599	$6,928	$7,268	$7,622	$7,993	$6,939	$7,308	$7,726	$8,166
Variable Costs (Excluding Fuel)-Total	$81,774	$89,145	$96,062	$103,985	$105,731	$111,927	$116,646	$124,569	$132,815	$142,656
Fuel Costs-Total	$2,279	$1,802	$1,891	$2,062	$2,109	$2,411	$3,648	$3,791	$4,326	$4,705
New Resource Debt Service-Total	$0	$0	$0	$0	$0	$0	$7,805	$7,805	$7,805	$7,805
Total Scenario Costs	$95,897	$97,547	$104,881	$113,315	$115,462	$122,331	$135,038	$143,472	$152,671	$163,332
Scenario 2 - Retire SLP 1,2,3 2015										
Fixed Costs-Total	$11,844	$11,620	$12,106	$12,609	$13,131	$13,675	$14,236	$14,823	$15,466	$16,138
Variable Costs (Excluding Fuel)-Total	$81,774	$88,708	$95,482	$103,362	$105,136	$111,283	$116,750	$124,678	$132,860	$142,728
Fuel Costs-Total	$2,279	$2,297	$2,468	$2,738	$2,839	$3,236	$3,633	$3,752	$4,307	$4,682
New EPA Retrofit Equip Debt Service-Total	$4,536	$4,536	$4,536	$4,536	$4,536	$4,536	$4,536	$4,536	$4,536	$4,536
Total Scenario Costs	$100,433	$107,160	$114,593	$123,245	$125,641	$132,730	$139,155	$147,790	$157,169	$168,084
Reduction in Annual Costs	*$4,536*	*$9,614*	*$9,712*	*$9,930*	*$10,179*	*$10,398*	*$4,117*	*$4,317*	*$4,497*	*$4,752*
Reduction in Current Budget Annual Costs		*$5,078*	*$5,176*	*$5,394*	*$5,644*	*$5,863*				
Scenario 3 - No Retirements										
Fixed Costs-Total	$11,844	$12,111	$12,390	$12,676	$12,968	$13,272	$13,582	$14,048	$14,675	$15,331
Variable Costs (Excluding Fuel)-Total	$81,774	$88,577	$95,228	$103,183	$104,883	$110,985	$116,415	$124,265	$132,349	$142,150
Fuel Costs-Total	$2,279	$2,513	$2,749	$3,062	$3,192	$3,735	$4,263	$4,357	$5,076	$5,468
New EPA Retrofit Equip Debt Service-Total	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996
Total Scenario Costs	$102,893	$110,197	$117,362	$125,916	$128,039	$134,988	$141,255	$149,665	$159,097	$169,944
Reduction in Annual Costs	*$6,996*	*$12,650*	*$12,481*	*$12,601*	*$12,577*	*$12,656*	*$6,217*	*$6,192*	*$6,425*	*$6,612*
Reduction in Current Budget Annual Costs		*$5,654*	*$5,485*	*$5,605*	*$5,581*	*$5,660*				

Fixed Costs includes: RPU resource Fixed O&M, Market Capacity and CROD Demand
Variable Costs includes: RPU resource Variable O&M, CROD Energy and Market Energy
Fuel Costs includes: RPU Resource fuel cost
Debt Service is for either new RPU resources added or for retrofit equipment for EPA NSR enforcement as applicable
Reductions determined from subtracting Scenario 1 from Scenario 2 or 3 as applicable

The accumulated benefit is shown graphically in Figures 4-1 and 4-2.

Figure 4-1 Cumulative Total Annual Cost Benefit Scenario 1 versus 2 ($000)

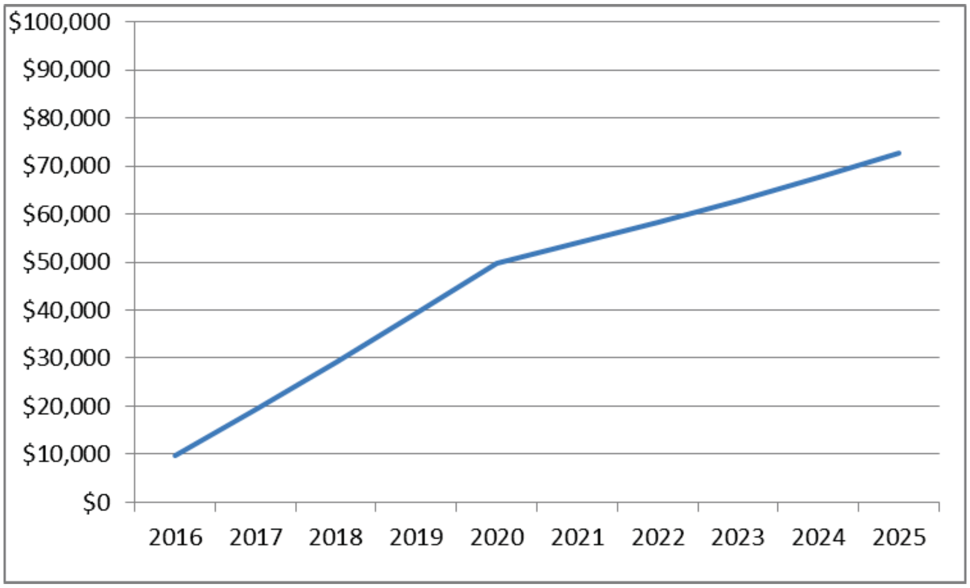
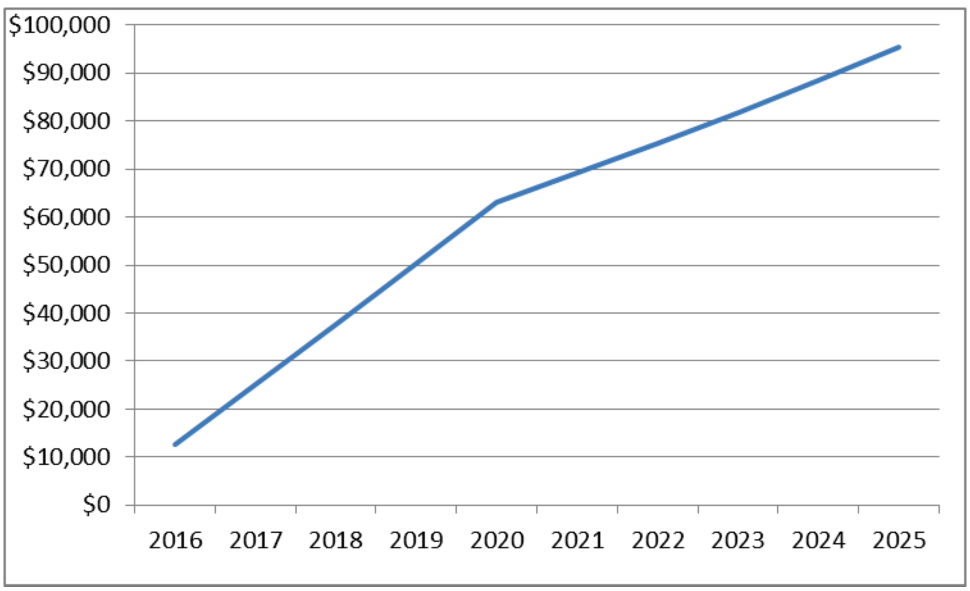


Figure 4-2 Cumulative Total Annual Cost Benefit Scenario 1 versus 3 ($000)



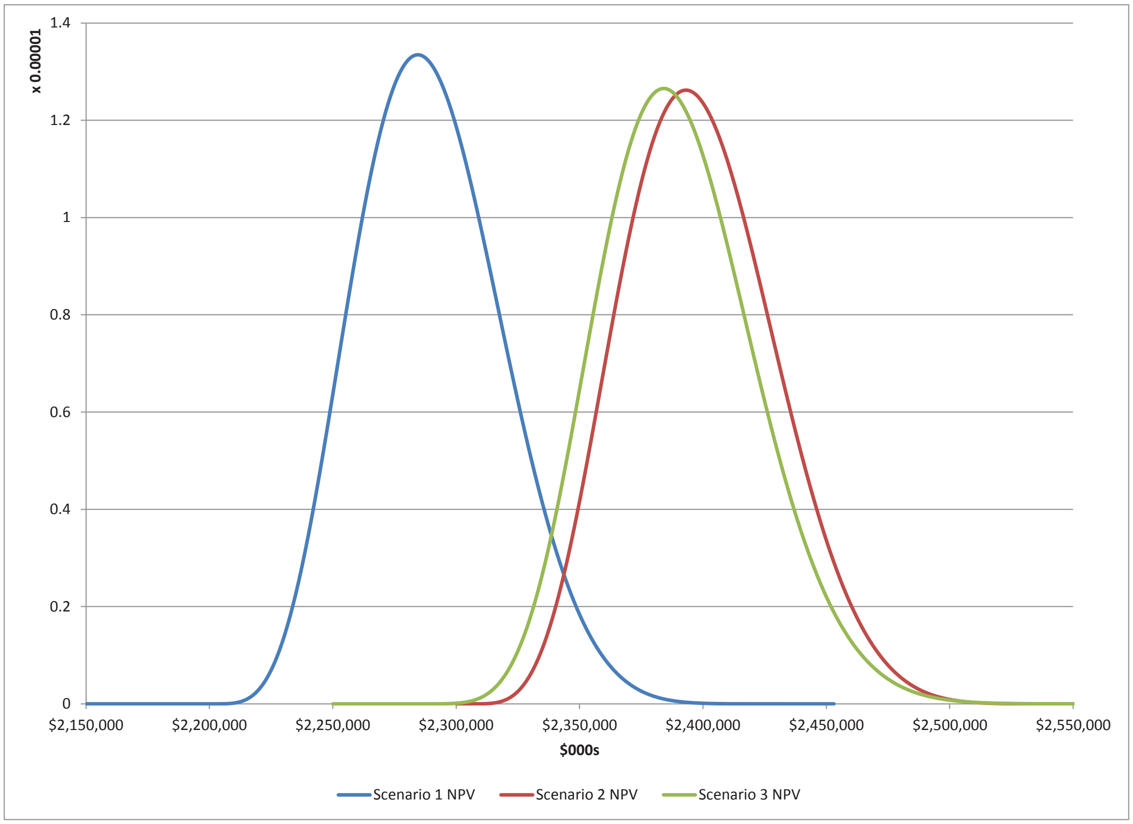
In interpreting the difference in benefits between the scenarios, care must be taken to understand which costs are actual benefits from currently incurred costs versus those that are avoided due to selection of a certain future. For instance, the savings from not investing in the emission equipment is not in the current RPU budget process and is not considered in the current RPU financials, whereas the reduction in SLP operation and maintenance costs directly affects a currently budgeted amount in the financials.

There are several assumptions associated with these scenarios. A sensitivity analysis was performed on several variables to review how changes in the assumption would impact the net present values of the three scenarios. The following assumptions were varied as indicated.

- Natural gas forecast – Increase up to $2 per mmbtu above the 2015 price with same escalation
- EPA associated capital cost – Adjust across the range of -30 percent to +20 percent
- Interest Rates – Increase up to 2 percent above current assumption
- Market capacity cost – Adjust across the range of +/- 20 percent
- Generator capital cost – adjust across the range of +/- 20 percent
- SLP coal – increase up to 5 percent

The variables were applied to the scenarios using an expected value distribution curve. The model then varied the assumptions across the range identified above to provide an overall distribution of the possible net present values. Figure 4-3 provides a summary of the results. Summaries of the models are provided in Appendix D.

Figure 4-3 Distribution Curves of Net Present Values of Scenarios 1-3



The most impacting of the assumptions is the price of natural gas. This cost affects the market price of energy. Since the amount of energy procured from the market is similar in all three scenarios, the resultant distributions have a similar shape. The results of the sensitivity analysis indicate that the Scenario 1 has a higher probability of being the future with the lower potential cost.

4.3 RPU FUTURE RESOURCE CONSIDERATIONS

RPU is continuing the transition to the time where it will be responsible for all of its power supply after the contract with SMMPA expires in 2030. This transition includes continuing with many current programs, confronting some significant near term issues and staying aware of how its investments support the longer term strategy.

4.3.1 2012 to 2021

RPU has made significant efforts to achieve the aggressive demand side management goals established in the 2005 Infrastructure Plan. This program has provided benefits as discussed earlier and is expected to continue to reduce the rate of growth of the RPU demand and energy requirements. The success of these programs will reduce the amount of capacity that RPU will be required to maintain in order to meet its capacity obligations with MISO.

The investments in the transmission system allow RPU to take advantage of market conditions when they are favorable to minimize its investments in resources and the amount of generation needed within the service area to maintain reliability. The ability to acquire capacity and energy from the market is currently a significant advantage.

Based on past analysis, RPU does not require additional renewable energy to meet its currently adopted RPS requirements until approximately 2025. The renewable energy from the Zumbro Hydro facility and the OWEF waste to energy plant provides sufficient renewable energy to meet the RPS requirements. Until that time, a majority of native load requirements above CROD levels occur during peak hours. Because of this constraint, wind, which generally has an output profile inverse to load requirements with most of its energy generated in off peak hours, is not a great fit for supplying renewable energy to RPU's load obligations above CROD.

Renewable energy generated over the peak hours is a better fit to meet RPU native load over the duration of the CROD agreement. For this reason, solar projects may be a more compatible resource to fulfill any deficit RPS requirements through the end of the CROD. Table 4-3 provides the amount of solar energy estimated to be delivered to the RPU system to satisfy its load above CROD for three years. As seen, even with the closer alignment of solar output with RPU load, there are several months where the load is such that no solar energy is provided above CROD. Based on the SMMPA CROD agreement, the energy below CROD has little value to RPU, but could be potentially of value to RPU customers. The solar energy output is estimated to be from an 1120W net AC solar PV fixed plate project using the solar insolence data from the Rochester airport. This data was modeled using the NREL solar PVsyst program.

Table 4-3 Solar Energy To RPU Grid

2012, 2015, 2020

Solar Power to Grid Monthly Totals (kWh)

	Below CROD			Above CROD		
	2012	**2015**	**2020**	**2012**	**2015**	**2020**
January	91.26	91.26	91.26	0.00	0.00	0.00
February	98.29	98.29	98.29	0.00	0.00	0.00
March	119.62	119.62	119.62	0.00	0.00	0.00
April	133.93	133.93	133.93	0.00	0.00	0.00
May	131.86	124.48	119.02	11.26	18.64	24.11
June	92.99	83.83	70.12	52.90	62.05	75.76
July	65.63	52.23	47.23	88.78	102.18	107.18
August	53.76	42.97	37.67	85.97	96.76	102.06
September	94.41	87.16	82.98	29.97	37.21	41.40
October	103.96	101.59	100.82	2.40	4.77	5.54
November	69.73	69.73	69.73	0.00	0.00	0.00
December	67.62	67.62	67.62	0.00	0.00	0.00

4.3.2 2022 to 2031

RPU will be making decisions about resource options as it moves toward 2031 when the CROD with SMMPA will have expired and the resources to meet the total capacity margin obligation will be provided by RPU. These decisions will be made in order to prepare the system for the post CROD operations.

The decision on the Silver Lake Plant may increase RPU's reliance on the MISO market. The current market conditions are favorable such that capacity is valued below the estimated cost assumed in the above analysis and significantly below the cost of constructing a new resource. The reliance on the market could prolong the need to add a local generating unit beyond what is shown in Scenario 1. The increase in firm transmission capacity to RPU through the CapX investments and the future cost of market capacity could allow RPU to rely on the market longer than considered in the above analysis.

The eventual investment in local gas-fired generation will support the system RPU will need to have in place when the CROD contract with SMMPA terminates in 2030. These investments will support the transition that RPU will be making to a utility that makes maximum use of the market when it is beneficial and relies on its own resources when the market costs increase. The investment in the capacity to replace the CROD, which is currently indicated to be a combined cycle unit, will be considered in light of the technology available at the time and the state of the market.

With the termination of the CROD arrangement, RPU will also be required to provide the total renewable energy requirements. The transition will allow RPU to make use of wind energy as well as solar in its renewable mix.

4.4 CONCLUSIONS

Based on the analysis provided above on the various scenarios associated with SLP units and the solar potential for RPU, Burns & McDonnell has developed the following conclusions.

1. RPU is confronted with additional investments needed for emission controls at SLP units due to the proposed EPA NSR Enforcement Action settlement counter proposal and the need to acquire capacity for its obligations in the 2021 time frame.

2. An analysis of various retirements versus retrofit scenarios indicates that retiring the SLP and acquiring replacement capacity from the market in the short term reduces the annual revenue requirements associated with RPU resources when compared to the two retrofit scenarios.

3. SLP Unit 4 is not anticipated to operate at any significant capacity factor in the future to meet RPU energy requirements or for energy sales into the MISO market.

4. Units developed in the future as replacements for SLP would help in positioning RPU for its post 2030 operations without the CROD. This would position RPU with assets that are more valued in the MISO market than the small coal units such as SLP Units 3 and 4.

* * * * *

APPENDIX A

STUDY ASSUMPTIONS

FINANCIAL ASSUMPTIONS

- Inflation/escalation rate: 2.5 percent (coal and debt service)
  4.1 percent (gas)
  3.0 percent (everything else)
- Interest rate: 4.50 percent
- Financing Period: 30 years (combined cycle)
  20 years (everything else)
- Discount rate for NPV calculations: 6.0 percent
- Actual 2006 hourly load shape used for system profile. This hourly load shape is then adjusted for each year to meet the peak demand and total annual energy.

GENERATION RESOURCES

Owned Generation:

<u>Cascade Creek 1</u>

- Gas fired combustion turbine
- Commercial operation on 6/1/1975
- 27 MW summer capacity
- 15,112 Btu/kWh heat rate
- Fixed O&M $7.41/kW-year, 2012$, escalated at inflation
- Variable O&M $1.50/MWh, 2012$, escalated at inflation
- 15.33% forced outage rate

<u>Cascade Creek 2</u>

- Gas fired combustion turbine
- Commercial operation on 4/1/2002
- 48 MW summer capacity
- 10,917 Btu/kWh heat rate
- Fixed O&M $4.17/kW-year, 2012$, escalated at inflation
- Variable O&M $1.50/MWh, 2012$, escalated at inflation
- 11.29% forced outage rate
- For SLP 1-4 retired case, fixed O&M is bumped up to 35.42/kW-year, 2012$, escalated at inflation

<u>Silver Lake Plant 1</u>

- Coal fired steam turbine
- Commercial operation on 8/1/1948
- 9.5 MW summer capacity
- 14,155 Btu/kWh heat rate
- Fixed O&M $10.84/kW-year, 2012$, escalated at inflation
- Variable O&M $2.99/MWh, 2012$, escalated at inflation
- 2.25% forced outage rate

<u>Silver Lake Plant 2</u>

- Coal fired steam turbine
- Commercial operation on 12/1/1953
- 14 MW summer capacity
- 14,705 Btu/kWh heat rate
- Fixed O&M $7.36/kW-year, 2012$, escalated at inflation
- Variable O&M $2.99/MWh, 2012$, escalated at inflation
- 3.05% forced outage rate

<u>Silver Lake Plant 3</u>

- Coal fired steam turbine
- Commercial operation on 11/1/1962
- 24 MW summer capacity
- 11,943 Btu/kWh heat rate
- Fixed O&M $14.71/kW-year, 2012$, escalated at inflation
- Variable O&M $2.99/MWh, 2012$, escalated at inflation
- 19.20% forced outage rate

<u>Silver Lake Plant 4</u>

- Coal fired steam turbine
- Commercial operation on 12/1/1969
- 45 MW summer capacity
- 12,078 Btu/kWh heat rate
- Fixed O&M $162.77/kW-year, 2012$, escalated at inflation (includes O&M and staffing for all of SLP)
- Variable O&M $2.99/MWh, 2012$, escalated at inflation
- 13.64% forced outage rate

<u>IBM</u>

- Two diesel fired combustion engines
- Commercial operation on 10/1/2005
- 3.6 MW summer capacity
- 9,589 Btu/kWh heat rate
- No variable or fixed O&M costs modeled

<u>Lake Zumbro</u>

- Hydroelectric plant
- Commercial operation on 11/1/1984
- 2 MW summer capacity
- Fixed O&M $18.56/kW-year, 2012$, escalated at inflation

<u>Olmsted Waste-to-Energy Facility</u>

- Solid waste fired steam turbine
- Commercial operation on 4/1/1987
- 2 MW summer capacity
- Variable O&M $1.00/MWh, 2012$, no escalation

Contract Purchases:

CROD

- 216 MW capacity
- Contract runs through 12/31/2030

	On-Peak ($/MWh)	Off-Peak ($/MWh)	Demand ($/kW-mo)	Trans. ($/kW-mo)
2015	$61.18	$46.24	$10.66	$2.66
2016	$64.80	$48.96	$10.66	$2.66
2017	$68.43	$51.68	$10.66	$2.66
2018	$72.70	$54.86	$10.66	$2.66
2019	$72.08	$54.35	$10.66	$2.66
2020	$74.74	$56.30	$10.66	$2.66
2021	$77.24	$58.11	$10.66	$2.66
2022	$80.64	$60.59	$10.66	$2.66
2023	$84.61	$63.47	$10.66	$2.66
2024	$88.86	$66.55	$10.66	$2.66
2025	$92.76	$69.35	$10.66	$2.66
2026	$86.80	$64.78	$10.66	$2.66
2027	$80.45	$59.92	$10.66	$2.66
2028	$83.79	$62.28	$10.66	$2.66
2029	$87.74	$65.07	$10.66	$2.66
2030	$92.88	$68.73	$10.66	$2.66

APPENDIX B

EPA REGULATION INFORMATION

The following is a brief introduction and a further discussion of the various EPA existing and proposed rules that are affecting electric utilities.

Environmental Programs and Acronyms
CAA - Clean Air Act: a comprehensive federal law that regulates air emissions from stationary and mobile sources. The law established the following regulatory programs:
National Ambient Air Quality Standards (NAAQS)
New Source Performance Standards (NSPS); and
National Emissions Standards for Hazardous Air Pollutants (NESHAPs);
New Source Review (NSR).

NAAQS - National Ambient Air Quality Standards: The CAA authorized the Environmental Protection Agency (EPA) to establish NAAQS to protect public health and public welfare. EPA set NAAQS for six principal pollutants, called "criteria" pollutants. These include Carbon Monoxide (CO), Lead (Pb), Nitrogen Dioxide (NO2), Ozone (O3), Particulate Matter (PM) and Sulfur Dioxide (SO2). These standards must be achieved at a regional level but may impact operations at a source level via permitting.

EPA Regional Haze Program - The Regional Haze Rule calls for state and federal agencies to work together to improve visibility in 156 national parks and wilderness areas. This rule affects both SLP and Cascade Creek.

CSAPR - Cross State Air Pollution Rule (CSAPR), requires states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. CSAPR requires a total of 28 states to reduce annual Sulfur Dioxide (SO2) emissions, annual Nitrogen Oxides (NOx) emissions and/or ozone season NOx emissions to assist in attaining the 1997 ozone and fine particle and 2006 fine particle National Ambient Air Quality Standards. This rule affects Unit 4 at SLP and the units at Cascade Creek.

NSPS - New Source Performance Standards: The NSPS are pollution control standards issued by EPA that dictate the level of pollution that a new stationary source may produce.

GHG - EPA began regulating greenhouse gases (GHGs) from mobile and stationary sources of air pollution under the Clean Air Act for the first time on January 2, 2011. Standards for mobile sources have been established.

NESHAPS - the National Emissions Standards for Hazardous Air Pollutants (NESHAPs) are emissions standards set by EPA for air pollutants not covered by NAAQS that may cause an increase in fatalities or in serious, irreversible, or incapacitating illness. Standards are set at a source level, i.e. source category, and require the maximum degree of emission reduction that the EPA determines to be achievable, MACT, (Maximum Achievable Control Technology).

IB MACT – The Industrial Boiler MACT, or IB MACT, addresses hazardous air pollutant emission standards for industrial, commercial and institutional boilers and process heaters with a heat input greater than 10 mmBtu per hour and creates emission limits for mercury

(Hg), particulate matter (PM), Hydrogen Chloride (HCl) and carbon monoxide (CO). This rule affects SLP units 1, 2, and 3

EGU MACT – The Electric Generating Unit MACT, or EGU MACT, addresses hazardous air pollutant emission standards for power plants greater 25MW and creates emission limits for mercury (Hg), particulate matter (PM), Hydrogen Chloride (HCl) and carbon monoxide (CO). This rule is also known as the Mercury and Air Toxics Standards (MATS). This rule affects SLP unit 4.

RICE NESHAP – EPA set a NESHAP for existing stationary reciprocating internal combustion engines (RICE) that either are located at area sources of hazardous air pollutants (HAP) emissions or that have a site rating of less than or equal to 500 HP and located at major sources of HAP emissions. This rule sets management practices and creates emission limits for carbon monoxide (CO). This rule affects the RPU diesel engines at IBM.

NSR - New Source Review: NSR is a permitting process that requires industry to undergo a pre-construction review for environmental controls if either a proposed new facility or any modifications to existing facilities would create a "significant increase" of a regulated pollutant. If a significant increase to a regulated pollutant occurs, the facility must install the Best Available Control Technology (BACT). "Routine scheduled maintenance" was exempt from the NSR process. However, the terms "significant increase" and "routine scheduled maintenance" have never been precisely defined and have resulted in many lawsuits filed by the EPA, public interest groups, and utilities.

114 Requests - A 114 request is a notice from the EPA of an investigation into an emission source's compliance with the Clean Air Act (CAA) under Section 114 of the Act, 42 U.S.C. § 7414. Section 114 of the CAA gives EPA broad powers to require a source to: Establish and maintain records; Make reports; Install monitoring equipment and take samples of emissions; and Provide such other information as the Administrator (as delegated to EPA Regions) may reasonably require. EPA employs its 114 Request authority broadly, typically requesting many categories of documents generated over many years. The potential scope of a 114 Request for a facility can be very large, particularly where EPA believes that an emissions source has engaged in projects that may have triggered the Act's New Source Review/Prevention of Significant Deterioration (NSR/PSD) provisions. The NSR/PSD provisions of the Act require permitting for any "major modification" to a source that results in a "significant net emissions increase."

Other EPA Acronyms

- AR - Acid Rain Program
- BMP - Best Management Practice
- CAAA - Clean Air Act Amendments
- CFR - Code of Federal Regulations
- ECHO – Environmental and Compliance History Online
- EIS - Environmental Impact Statement
- EQB - Environmental Quality Board
- FR - Federal Register
- NO - Nitric Oxide

CROSS STATE AIR POLLUTION RULE

On July 6, 2010, the EPA proposed a Clean Air Transport Rule (CATR) to reduce interstate transport of SO_2 and NO_x, which are precursors to O_3 and fine particulate matter ($PM_{2.5}$). On July 7, 2011, the EPA finalized the CATR as the Cross State Air Pollution Rule (CSAPR). This rule was promulgated on August 8, 2011. The final CSAPR set state-wide budgets for annual SO_2 and NO_x emissions, as well as ozone-season NO_x emissions, in 27 eastern states and the District of Columbia (D.C). These state budgets take effect in 2012. The CSAPR applies only to fossil fuel-fired Electric Generating Units (EGUs) with capacities greater than 25 MW. The rule also established Federal Implementation Plans (FIPs) for each affected state; however, states could also create their own State Implementation Plan (SIP) for the CSAPR.

On December 30, 2011, the U.S. Court of Appeals for the D.C. Circuit stayed the CSAPR. The Court also ordered all parties involved to propose formats and schedules for briefing the CSAPR cases by January 17, 2012.the case was heard in April 201, however, no decision has been made. Until the CSAPR is reconsidered, the Clean Air Interstate Rule (CAIR) is in effect.

The CSAPR is designed to help states achieve compliance with the following National Ambient Air Quality Standards (NAAQS):

- $PM_{2.5}$ NAAQS set in 1997 (annual standard)
- $PM_{2.5}$ NAAQS set in 2006 (24-hour standard)
- O_3 NAAQS set in 1997 (8-hour standard)

In the CSAPR, the EPA determined that 23 states, including Minnesota, impact $PM_{2.5}$ concentrations in downwind states and are therefore subject to annual SO_2 and NO_x budgets. The EPA also determined that 20 states impact O_3 concentrations in downwind states and are therefore subject to ozone-season NO_x budgets. Note that the ozone season is defined as May 1 through September 30. Minnesota is not included in the final CSAPR ozone-season NO_x program. The CSAPR includes two tiers of annual SO_2 budgets. “Group 1” states, will have an SO_2 budget that decreases in 2014. “Group 2” states, including Minnesota, have the same SO_2 budget in 2012 and 2014. Under the final CSAPR, a state’s emission budget is allocated to affected sources within the state based on each unit’s historic heat input and maximum historic allowances. Interstate trading of emissions allowances is allowed.

On October 6, 2011, the EPA proposed revisions to the CSAPR. The proposal revised the state budgets for Florida, Louisiana, Michigan, Mississippi, Nebraska, New Jersey, New York, Texas, and Wisconsin, as well as the new unit set-asides in Arkansas and Texas. The proposal also revised the unit-level allocations in Alabama, Indiana, Kansas, Kentucky, Ohio, and Tennessee to better account for utility consent decrees.

On July 7, 2011, the EPA also issued a Supplemental Notice of Proposed Rulemaking (SNPR) related to the CSAPR. In the SNPR, the EPA proposed to expand the CSAPR ozone-season NO_x program to include Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin. On February 7, 2012, the EPA finalized these revisions to the CSAPR in the ozone-season NO_x program. These revisions included an increase in the state-wide annual NO_x and ozone-season NO_x budgets for some states compared to those included on the SNPR.

The CSAPR does not address the current O_3 NAAQS finalized in March 2008 or the O_3 NAAQS proposed in January 2010. The EPA plans to address compliance with these NAAQS in a follow-up rule (the "Transport Rule II"). EPA expected to propose this rule in the summer of 2011 and finalize it in the summer of 2012. However, at the time of this report, this rule has not been proposed or finalized.

The EPA is also reviewing the $PM_{2.5}$ NAAQS finalized in 2006. In March 2010, the EPA issued a policy assessment report that recommended that the annual $PM_{2.5}$ standard be reduced and that the 24-hour $PM_{2.5}$ standard be either retained or reduced. The EPA expected to propose a new $PM_{2.5}$ NAAQS in November 2010 and finalize the standard by July 2011. However, the November 2010 date was not met. EPA is not expected to finalized the standard until 2013. Around the time the $PM_{2.5}$ NAAQS is finalized, the EPA expects to propose the Transport Rule II. It is not known at this time if the final Transport Rule II will incorporate the revised $PM_{2.5}$ standard. If the Transport Rule II does address the revised $PM_{2.5}$ standard, it will only require additional annual SO_2 and/or NO_x reductions from sources in Minnesota if SO_2 and/or NO_x emissions from these sources are thought to contribute to $PM_{2.5}$ NAAQS non-attainment areas in a downwind state.

In the proposed CSAPR, the EPA dictated that each state set aside 2 to 3 percent of its annual SO_2 and NO_x budget and ozone-season NO_x budget for new units. This new unit set-aside is reflected in EPA's proposed unit-level allowance allocations.

Table B-1 summarizes the allowance allocations proposed by the EPA for RPU's units.

Table B-1. Anticipated CSAPR Allowances Allocations for RPU[1]

Unit	Annual NOx Allowances	Annual SO2 Allowances
Silver Lake 4	145	215

[1]From EPA Allowance Allocation Table included with the Technical Support Documents for the final CSAPR.

Recent operations at Silver Lake Unit 4 have resulted in emission levels well below the CSAPR allowances. For NOx, the plant emitted 17 tons of NOx and 19 tons of SO2. The 2011 emissions were even lower.

INDUSTRIAL BOILER MACT

On March 21, 2011, under the authority of Section 112 of the Clean Air Act, the Environmental Protection Agency (EPA) promulgated National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process Heaters. This NESHAP must be based on application of the Maximum Achievable Control Technology (MACT) and is, therefore, often referred to as the Industrial Boiler MACT rule. The Industrial Boiler MACT rule limits the emissions of certain hazardous air pollutants (HAPs) from industrial, commercial, and institutional boilers. Full compliance with the Industrial Boiler MACT rule was required by March 21, 2014, three years from the date of the final promulgation.

However, on May 18, 2011, the EPA stayed the effective date of the Industrial Boiler MACT rule. The stay gave the EPA additional time to reconsider certain aspects of rule. The EPA indicated that they did not have enough time to properly evaluate all of the data received prior to the court ordered deadline to promulgate the rule in March 2011. As a result of the reconsideration, on December 2, 2011 the EPA re-proposed the rule. The re-proposed rule contained revised emission limits and compliance date. The EPA expects to finalize the re-proposed rule by late spring 2012 and compliance would be required three years later in late spring 2015.

The Industrial Boiler MACT rule overview provided below is based on the re-proposed rule of December 2, 2011.

Emission Limit Requirements

The Industrial Boiler MACT rule applies to any facility incorporating industrial, commercial, or institutional boilers or process heaters that are located at a major source of HAP emissions. A major source of HAP emissions is defined as any stationary source or group of stationary sources located within a contiguous area and under common control that emits, or has the potential to emit, 10 tons per year or more of any single HAP or 25 tons per year of any combination of HAPs. Electric utility boilers that are 25 MW or less are also subject to the rule. The Industrial Boiler MACT Rule sets emission limits for the following HAPs:

- Particulate Matter (PM) or, alternatively, Total Selected Metals (TSM)
- Hydrogen Chloride (HCl)
- Mercury
- Carbon Monoxide (CO)

One of the major changes from the March 2011 rule to the current re-proposed rule is that dioxins/furans was removed from the pollutants for which emissions limits have to be met.

The emission limits are based on a sub-categorization of sources. New and existing boilers that burn a solid fuel, liquid fuel, or gaseous fuel (other than natural gas) are subject to emission limits. Another major change from the March 2011 rule to the current re-proposed rule is that emission limits were revised. The emission limits for existing solid fuel fired boilers are shown in Table B-2.

Table B-2. Proposed Rule Emission Limits For Existing Solid Fuel Boilers[1,2,3]

(Emission Limits from the Stayed March 2011 Rule are Shown in Parentheses)

Fuel Subcategory	Boiler Subcategory	HCl lb/MMBtu	Hg lb/TBtu	PM lb/MMBtu	or TSM lb/MMBtu	CO[4] 3-run avg / 10-day roll avg. (ppmvd @ 3% O2)
Coal / Solid Fossil Fuel	Stoker	0.022 (0.035)	3.1 (4.6)	0.028 (0.039)	8.3×10^{-5}	220 / 34 (270)
	Fluidized Bed			0.088 (0.039)	1.7×10^{-5}	56 / 59 (82)
	Pulverized Coal			0.044 (0.039)	5.9×10^{-5}	41 / 28 (160)
Biomass / Bio-Based Solid	Stoker/Sloped Grate Wet Biomass	0.022 (0.035)	3.1 (4.6)	0.029 (0.039)	5.7×10^{-5}	790 / 410 (490)
	Stoker/Sloped Grate Kiln-Dried Biomass			0.32 (0.039)	4.0×10^{-3}	250 / NA (490)
	Fluidized Bed			0.11 (0.039)	1.2×10^{-3}	370 / 180 (430)
	Suspension Burners			0.051 (0.039)	1.1×10^{-3}	58 / 1,400 (470)
	Dutch Ovens / Pile Burners			0.036 (0.039)	2.4×10^{-4}	810 / 440 (470)
	Fuel Cell			0.033 (0.039)	4.9×10^{-5}	1,500 / NA (690)
	Hybrid Suspension Grate			0.44 (0.039)	4.9×10^{-4}	3,900 / 730 (3,500)

[1]The emission limits apply to boilers with a heat input capacity of 10 MMBtu/hour or greater. Limited use boilers are not subject to the emission limits.

[2]The rule also establishes alternative output based emission limits (not shown) for each of the emission limits in this table.

[3]Emission limits must be met at all times except for start-up/shutdown periods during which emissions must be minimized.

[4]The CO emission limit has an alternative 10-day rolling average (as demonstrated by a CO CEMS) emission limit for each CO emission limit.

Certain boiler subcategories do not have emission limits and instead must only meet a work practice standard, which consists of conducting a periodic boiler tune-up. Also, any Boiler MACT affected facility with an existing boiler has a work practice standard to conduct a one-time energy assessment of the facility performed by a qualified energy assessor prior to the compliance date. This information is summarized in Table B-3.

Table B-3. Industrial Boiler MACT Work Practice Standards

Source	Boiler Subcategory	Work Practice Requirment
New or Existing Boilers	Heat input capacity < 5 MMBtu/hr in the following subcategories: Gas 1, Gas 2, Light Liquid	Conduct a boiler tune-up every 5 years
New or Existing Boilers	1. Heat input capacity $\geq$ 5 but < 10 MMBtu/hr in the following subcategories: Gas 1, Gas 2, Light Liquid 2. Heat input capacity < 10 MMBtu/hr in the following subcategories: Heavy Liquid, Solid Fuel	Conduct a boiler tune-up every 2 years
New or Existing Boilers	All Boilers with a heat input capacity > 10 MMBtu/hr	Conduct a tune-up every year
New or Existing Boilers	Any new or existing boiler subject to emission limits	1. Demonstrate good combustion practices are maintained by monitoring O_2 2. Operators trained in startup/shutdown (SS) procedures and procedures to minimize emissions. 3. During SS periods, maintain records including O_2 data, length of SS and reason for SS.
Existing Boilers	A major source facility containing an existing boiler	Conduct a one-time energy assessment of the facility

Annual Compliance Demonstration Requirements

The Industrial Boiler MACT rule also sets standards for how sources subject to the rule are required to demonstrate annual compliance with the emission limits. Annual compliance is demonstrated by:

- Conducting performance tests and establishing operating limits, or by
- Conducting fuel analyses and performing calculations to demonstrate that the pollutant concentration in the fuel is less than the emission limit. This applies only to mercury and HCl.

The purpose of the performance tests is to demonstrate annual compliance with the emission limits and to establish each boiler's operating limits, where applicable, to be used in the continuous compliance demonstration. The performance tests must be conducted annually. If the performance tests show that the emissions are at or below 75 percent of the emission limit for a given pollutant for three years in a row, then a performance test for that pollutant does not have to be conducted for three years.

A facility may demonstrate compliance with the emission limits for PM, HCl, or mercury by averaging emissions across the existing boilers in the same subcategory at a facility provided that the averaged emissions are 90 percent or less of the applicable emission limit. New boilers added to a facility may not be included in the emissions average.

Continuous Compliance Demonstration Requirements

In addition to demonstrating annual compliance, a facility subject to the Industrial Boiler MACT rule must demonstrate continuous compliance until the next compliance demonstration date (annually or every third year). To demonstrate continuous compliance, the facility must monitor and comply with the applicable site-specific operating limits established during the performance tests or fuel analysis. The site-specific operating limits vary depending on the type of pollution control equipment employed by the facility. The following continuous compliance requirements will apply based on the pollution control equipment employed:

- A boiler with a fabric filter must maintain opacity to 10 percent or less (daily block average) or install and operate a bag leak detection system.
- A boiler with an ESP must maintain opacity to 10 percent or less (daily block average).
- A boiler with a dry scrubber or carbon injection must maintain the minimum sorbent or carbon injection rate (corrected for boiler load) measured during the most recent performance test.
- A boiler subject to a carbon monoxide limit must install and operate an oxygen analyzer system or carbon monoxide Continuous Emissions Monitoring System (CEMS). If an oxygen analyzer system is used, the boiler oxygen trim system must operate with the oxygen level set at the minimum oxygen level that is established as the operating limit.
- Any boiler with an average annual heat input rate greater than 250 mmBtu/hr must have a PM Continuous Parameter Monitoring System (CPMS). *Note: This is a subtle, but important change in the proposed rule. In the stayed March 2011 rule, a boiler with a rated heat input capacity greater than 250 mmBtu/hr was required to install a PM CEMS. The re-proposed rule changes the language to state "annual average heat input rate" instead of "rated heat input" and changes the language to state "PM CPMS" instead of "PM CEMS". EPA will have to provide greater clarification in the final rule on the meaning of a PM CPMS.*

UTILITY BOILER MACT

In February 2008, the Clean Air Mercury Rule (CAMR), a nation-wide mercury cap-and-trade program, was vacated by the U.S. Court of Appeals for the District of Columbia. As a result of this decision, the

EPA was required to develop a Maximum Achievable Control Technology (MACT) standard for Electric Generating Units (EGUs) under Section 112 of the Clean Air Act (CAA). This regulation is also known as the National Emission Standards for Hazardous Air Pollutants (NESHAP) from Coal- and Oil-Fired Electric Utility Steam Generating Units, or the Utility Boiler MACT. The EPA promulgated the rule (also known as the Mercury and Air Toxics Standard, or MATS) on February 16, 2012. Existing sources will have three (3) years and 60 days from the promulgation date to comply with the rule, making the compliance date April 16, 2015.

Emission Limit Requirements

The Utility Boiler MACT rule applies to any electric utility steam generating unit (EGU) of more than 25 MW that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MW output to any utility power distribution system for sale is considered an EGU. The Utility Boiler MACT Rule sets emission limits for the following HAPs:

- Non-Mercury Metallic HAPS (sources can choose to comply with emission limits for filterable particulate matter, total HAP metals, or individual metals)
- Acid Gas HAPs (HCl is used as a surrogate. Some sources can choose to comply with emission limits for SO_2 instead if they employ a wet or dry Flue Gas Desulfurization (FGD) system and an SO_2 CEMS system)
- Mercury

The emission limits are based on a sub-categorization of sources. New and existing boilers that burn coal or oil, or are Integrated Gasification Combined Cycle (IGCC) units are subject to the emission limits. Emission limits for coal-fired boilers are further sub-categorized between units that burn lignite and units that burn coals other that lignite. EGUs subject to the Utility Boiler MACT that are under the same ownership, at the same plant site, and in the same subcategory may demonstrate compliance by averaging their emissions.

Table B-4 lists the emission limits for coal-fired boilers set by the Utility Boiler MACT standard. Table B-5 lists the emissions limits for individual metals for coal-fired boilers set by the rule. No emission limits were included for organic HAPs or dioxins and furans. Instead, a work practice standard is included that would require an inspection of a boiler that is subject to the rule every 36 months.

Table B-4. Utility Boiler MACT Rule Emission Limits for Coal-Fired Boilers

	Non-Mercury Metallic HAP[1]			Acid Gas HAP[2]		Mercury
Regulatory Option	Filterable PM	Total HAP Metals	Individual Metals	HCl Surrogate	SO_2 Surrogate	
Existing Units	0.030 lb/mmBtu	0.000050 lb/mmBtu	See Table 4-5	0.0020 lb/mmBtu	0.20 lb/mmBtu	1.20 lb/TBtu[3] 0.0130 lb/GWh[3]
	0.30 lb/MWh	0.00050 lb/MWh		0.020 lb/MWh	1.5 lb/MWh	4.0 lb/TBtu[4] 0.040 lb/GWh[4]
New Units	0.0070 lb/MWh	0.000060 lb/MWh	See Table 4-5	0.40 lb/GWh	0.40 lb/MWh	0.00020 lb/GWh[3]
						0.040 lb/GWh[4]

[1]Units may choose to comply with the limits for either filterable PM, total HAP metals, or individual metals.
[2]Units that use a FGD system and SO_2 CEMS may choose to comply with the SO_2 limit as an alternative to the HCl limit. All other units must comply with the HCl limit.
[3]For units designed to burn coals other than lignite.
[4]For units designed to burn lignite.

Table B-5. Utility Boiler MACT Rule Individual Metal Emission Limits for Coal-Fired Boilers

	Existing Units		New Units
HAP Metal	**lb/TBtu**	**lb/GWh**	**lb/GWh**
Antimony	0.80	0.0080	0.0080
Arsenic	1.1	0.020	0.0030
Beryllium	0.20	0.0020	0.00060
Cadmium	0.30	0.0030	0.00040
Chromium	2.8	0.030	0.0070
Cobalt	0.80	0.0080	0.0020
Lead	1.2	0.020	0.0020
Manganese	4.0	0.050	0.0040
Nickel	3.5	0.040	0.040
Selenium	5.0	0.060	0.0060

The work practice standard for organic HAPs or dioxins and furans must include a combustion process tune-up, inspection of the equipment, and optimization to minimize emissions of NO_x and CO. The work practice standard involves the following:

- Inspect each burner, and clean or replace any components of the burner as necessary.
- Inspect the flame pattern and make any adjustments to the burner necessary to optimize the flame pattern.
- Observe the damper operations and make any needed adjustments or repairs to dampers, controls, mills, pulverizes, cyclones, and sensors.
- Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly.
- Optimize total emissions of carbon monoxide (CO) and NO_x.
- Measure the concentration in the effluent stream of CO and NO_x (in parts per million by volume, ppmv) and oxygen (in volume percent) before and after the adjustments are made.
- Maintain on-site and submit, if requested, an annual report of the inspection and any corrective actions taken.
- Submit a notice of completion of the performance tune-up to EPA within 60 days after the date of completing each performance tune-up.

The inspections required by the work practice standard must be completed every 36 months. However, if a neural network is employed, this inspection is required once every 48 months.

Initial Compliance Demonstration Requirements

The Utility Boiler MACT rule (also called the Mercury and Air Toxics Standards, or MATS) includes requirements for demonstration of compliance with the emission limits it sets. Compliance demonstration is required by a combination of initial performance testing and continuous monitoring.

Compliance with each applicable emission limit must be demonstrated during an initial performance test. The initial performance test may be a 30-day period of operation of continuous emissions monitoring systems (CEMS) or it may be a stack test based on three test runs using the stipulated EPA Test Methods.

Emission limits for which compliance demonstration may be demonstrated by an initial performance test using CEMS include those for SO_2, HCl, or PM (using a PM CEMS). For demonstration of compliance with the emission limitations for mercury, only continuous monitoring using a mercury CEMS or a sorbent trap monitoring system is allowed.

If initial compliance with the emission limitations for filterable PM, Total HAP Metals, or individual HAP metals is demonstrated via stack testing, then ongoing compliance demonstration must be performed using either a PM continuous parametric monitoring system (PM CPMS) or by repeating the compliance stack testing on a quarterly basis. If the PM CPMS option is selected, then operating limits set during the performance test are used to determine ongoing compliance, as described in the next section.

The Utility Boiler MACT also establishes a work practice standard requiring a tune-up of the burner and combustion controls on a regular basis. The completion of the initial tune-up is required as part of the initial compliance demonstration.

Continuous Compliance Demonstration Requirements

Following the initial compliance demonstration as discussed above, a facility subject to the Utility Boiler MACT rule must continue to demonstrate continuous compliance. The emission limits set by the Utility Boiler MACT are 30-day rolling averages. Note that these emission limits do not apply during periods of start-up and shut down. However, work practice standards included in the rule effectively limit emissions during these periods. The work practice standards require the use of "clean fuels" (natural gas or distillate oil) for ignition during startup, and dictate the use of all installed air pollution control technologies, within practical limits, during periods of startup and shutdown when coal is being fired.

The work practice standard requiring a tune-up of the burner and combustion controls requires that continuous compliance be demonstrated by repeating the tune-up every 36 months. This frequency may be reduced to every 48 months if neural network combustion optimization software is used.

For those emission limits for which initial compliance demonstration was made using CEMS (including mercury CEMS or sorbent trap monitoring system), the continued use of CEMS will be required to demonstrate continuous compliance.

If stack testing is used to demonstrate initial compliance, then those stack tests must be repeated on a quarterly basis to continue to demonstrate continuous compliance. An exception applies where initial compliance with the emission limitations for filterable PM, Total HAP Metals, or individual HAP metals is demonstrated via stack testing and the owner elects to use a PM CPMS to verify continuous compliance. In that case a site-specific operating limit will be established during the initial performance test, based on data produced by the PM CPMS during that test. Then that operating parameter must be maintained, on a 30-day rolling average basis, at or below the highest 1-hour average value measured during the performance test. The operating limit will be reset during each subsequent annual performance test.

REGIONAL HAZE RULE

On July 1, 1999, the EPA issued a Regional Haze Rule (40 CFR Part 51, Subpart P) aimed at protecting visibility in 156 Federal Class I areas. Subsequently, the EPA issued proposed guidelines for determining Best Available Retrofit Technology (BART), which provides guidance to the States in determining the air pollution controls needed to reduce visibility-impairing pollutants. On July 6, 2005, the EPA finalized amendments to its Regional Haze Rule and its BART Guidelines.

BART is defined as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant." BART requirements will apply to facilities that were not yet operating on August 7, 1962 but were in existence on August 7, 1977 (the date of enactment of the Clean Air Act Amendments of 1977) and that have the potential to emit more than 250 tons per year of any visibility-impairing pollutant (SO_2, NO_x, or particulate matter). If any visibility-impairing pollutant is emitted above this threshold level, then that source is BART-eligible. Next, it must be determined whether emissions from a BART-eligible facility are reasonably anticipated to contribute to, or cause, visibility impairment in any Federal Class I area. A BART review is required for each visibility-impairing pollutant.

Under the Regional Haze Rule, states must determine which sources will have to install BART controls and then must submit a state implementation plan (SIP). SIPs were due to the EPA in December 2007. The EPA was required to act on any regional haze SIPs that had been submitted and promulgate a federal implementation plan (FIP) for each state that does not have an approved Regional Haze Rule SIP by January 15, 2011. This would have made the legal compliance date for any emission limitation included in either a state Regional Haze Rule SIP or the EPA's FIP five years from that date, or January 15, 2016. EPA failed to meet its court-ordered deadline, and subsequently reached a new agreement to approve SIPs or promulgate FIPs for the Regional Haze Rule in a schedule that would have all plans issued by the end of 2012. EPA finalized the Minnesota the Minnesotai Regional Haze SIPin June, 2012.

Many states based their Regional Haze Rule SIPs on compliance with the Clean Air Interstate Rule (CAIR). The CAIR was an earlier version of the CATR and CSAPR.. The CAIR was promulgated on May 12, 2005, but was remanded back to the EPA in December 2008. The CATR was designed to replace the CAIR program. The Regional Haze Rule includes a provision that allows states to use CAIR to meet the requirements of the Regional Haze Rule. Many states originally based their Regional Haze Rule SIPs on this "CAIR-as-BART" provision. CAIR was replaced by CSAPR in July 2011. EPA recently declared that EGU's, such as Silver Lake 3 and 4, will not be required to establish new regional haze SO2 and NOx emission limits if they are located in a CSAPR state. Since Minnesota is a CSAPR state, the Minnesota Regional Haze SIP uses this provision to exempt Silver Lake from regional haze requirments.

NATIONAL AMBIENT AIR QUALITY STANDARDS

The EPA is required to set limits on ambient air concentrations for each criteria pollutant (SO_2, NO_2, CO, O_3, lead, and PM) to protect the public's health and welfare. The EPA is required to review these NAAQS and the latest health data periodically, and modify the standards if needed.

On January 22, 2010, the EPA finalized a new 1-hour primary NAAQS for NO_2 (100 ppb). On June 2, 2010, the EPA finalized a new 1-hour NAAQS for SO_2 (75 ppb). At this time, the EPA also rescinded the 24-hour and annual SO_2 standard. The new NO_2 and SO_2 standards are much more stringent than the previous standards. For example, the new 1-hour SO_2 standard is lower than the previous 24-hour standard (140 ppb). Demonstrating compliance with the new NO_2 and SO_2 standards will be challenging. Compliance with a NAAQS is traditionally proven by either air dispersion modeling or ambient air monitoring. Air dispersion modeling results are typically very conservative compared with ambient air monitoring results. For this study, no detailed air dispersion modeling or ambient air monitoring has been performed. However, compliance with the new NO_2 and SO_2 NAAQS could require air pollution controls in some cases.

Attainment with the new SO_2 and NO_2 NAAQS are expected to be required by 2017 and 2021, respectively. In order to meet the new SO_2 and NO_2 NAAQS by these timeframes, action may be required sooner at sources found to impact concentrations of these pollutants in non-attainment areas. Demonstrating compliance is based on 3 years' worth of monitoring data, so states may require emissions controls several years before the compliance date. Under the new standards, modifications to the SO_2 and NO_2 monitoring networks are required by January 1, 2013. Once three years of data have been collected, a state may decide to start taking action to achieve attainment. Note that the NO_2 standard is expected to be re-reviewed in January 2015, so states may wait until after this review to take action.

In addition to the new NO_2 and SO_2 NAAQS discussed above, the EPA is also proposing to tighten the NAAQS for O_3 and $PM_{2.5}$. On January 19, 2010, the EPA proposed to revise the 8-hour primary NAAQS for O_3 from 75 ppb to a level in the range of 60 to 70 ppb. EPA expected to finalize the new standard by July 2011. In September 2011, the EPA withdrew its proposed changes to the 2008 O_3 NAAQS. The EPA intends to reconsider the 2008 standard in 2013. Ozone formation is impacted by emissions of volatile organic compounds and NO_x. If the EPA proposes a new O_3 standard in 2013 as expected, attainment with the new standard is expected to be required between 2017 and 2034, depending on the severity of the non-attainment issue.

The EPA set the current $PM_{2.5}$ standard on September 21, 2006. At this time, the EPA revised the 24-hour standard, but made no changes to the previous annual standard. However, a decision by the D.C. Court of Appeals now requires the EPA to review the annual $PM_{2.5}$ standard. EPA expected to finalize the reconsideration of the 2006 standard by July 2011, but this has not been done as of the writing of this report. $PM_{2.5}$ primarily consists of sulfate and nitrate particles which are created from SO_2 and NO_x emissions. Attainment with the new standard is expected to be required between 2014 and 2031, depending on the severity of the non-attainment issue.

COAL COMBUSTION RESIDUE REGULATIONS

In December 2008, a large ash spill occurred at the Tennessee Valley Authority (TVA) Kingston plant about 40 miles west of Knoxville when an earthen retaining wall of the plant's ash pond gave way. A large amount of ash was spilled, and the damage to the surrounding area was extensive. Due to the failure of TVA's ash pond, the EPA has decided to relook at the disposal and handling of coal combustion residues (CCR).

On June 21, 2010, the EPA issued proposed CCR rules. In this rulemaking, the EPA is proposing two regulatory options, generally termed the "Subtitle C" and "Subtitle D" options. Both of these options would be administered under the Resource Conservation and Recovery Act (RCRA).

Under RCRA Subtitle C, CCR would be considered a special waste, but generally would be treated as a hazardous waste. Under this approach, CCR would be regulated at the federal and state level with a "cradle to grave" approach (i.e., from CCR material generation through disposal). The EPA was careful to list this as a "special waste" because a hazardous waste designation would limit beneficial ash reuse. Designating CCR as hazardous waste would significantly impact ash that has already been disposed. Existing ash ponds would be required to close within seven (7) years and no new ponds would be allowed. Wet ash handling and storage systems would need to be converted to dry systems.

Under RCRA Subtitle D, CCR materials would be regulated based on a citizen rule approach. This approach defines a set of national minimum criteria, and only the disposal of the CCR materials would be covered with these regulations. Under RCRA Subtitle D, existing ponds would require closure, unless the pond was properly lined within seven (7) years. New ash ponds can be constructed, as long as composite liners are used and groundwater monitoring is performed.

Both the Subtitle C and Subtitle D options set forth regulatory requirements for both new and existing surface impoundments (ponds) and landfills, including but not limited to location restrictions, monitoring, liner systems, leachate collection and management, closure and post-closure care, and effective dates for implementation of the rules. One significant concern with the RCRA Subtitle C option in particular is that it would effectively phase out wet CCR storage pond operations.

CWA 316(A) AND (B) AND WATER DISCHARGE LIMITATIONS

There are three major water regulations that are currently being developed by the EPA that could potentially impact coal-fired power plants: Section 316(a) of the Clean Water Act (CWA), CWA Section 316(b), and potential changes to the National Pollutant Discharge Elimination System (NPDES) Program. Provisions of Section 316(a) of the CWA apply to thermal discharges. This regulation may require the use of a cooling tower at facilities that do not currently use one. Provisions of Section 316(b) of the CWA apply to water intakes. Power plants subject to this rule may be required to re-design their cooling water intake structures to protect aquatic life, unless a cooling tower designed for compliance with Section 316(a) is used.

The federal effluent guidelines for coal-fired units have come under scrutiny now that more of these plants are installing wet Flue Gas Desulfurization (FGD) systems. The EPA has therefore stated that it will revise the standards for steam generating units under the NPDES program. The blowdown from an FGD system may contain metals such as arsenic, selenium, and mercury. The EPA is likely to set discharge limits for these metals. These metals can potentially be treated in various ways. However, a biotreatment or a zero liquid discharge (ZLD) system may be required. The EPA has issued an Information Collection Request (ICR) for FGD system effluents to develop this rule. Discharges from ponds and other wastewater streams may be addressed in this rulemaking.

NSPS, NSR, AND PSD IMPLICATIONS

It is important to note that the addition of air pollution control equipment to an existing unit is not exempt from the Prevention of Significant Deterioration (PSD) or New Source Review (NSR) construction permitting programs. For example, carbon dioxide (CO_2) emissions from a retrofit wet FGD system may trigger PSD requirements. The addition of air pollution control equipment, or related modifications, may also subject the unit to a New Source Performance Standard (NSPS). The addition of air pollution control equipment may be a potential compliance option for the air quality regulations discussed in this section. In each case, the addition of air pollution control equipment should be evaluated to determine if NSR, PSD, or NSPS requirements are triggered.

OTHER PERMITTING ISSUES

In addition to the NSPS, NSR, and PSD issues addressed above, any operational changes made or air pollution control equipment added to comply with current and future air quality regulations will have to be incorporated into a facility's Title V operating permit. Permitting may also be required for any measures undertaken to comply with future CCR and water discharge regulations. Any new water discharge points from a wet FGD system will need to be added to the plant's existing NPDES permit (if a new discharge point is even allowed). If modifications are made to an existing ash pond to comply with future CCR regulations, these modifications may need to be incorporated into the appropriate permits.

APPENDIX C

STRATEGIST OUTPUT

Scenario 1: Retire All Silver Lake Plant in 2015 – Base Case

SUMMARY OF COSTS			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Fixed Costs-Total	**$000**		**$11,844**	**$6,599**	**$6,928**	**$7,268**	**$7,622**	**$7,993**	**$6,939**	**$7,308**	**$7,726**	**$8,166**	**$8,634**	**$9,123**	**$7,984**	**$8,493**	**$9,033**
SLP 1, 2, 3	$000		$603	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SLP 4	$000		$7,896	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cascade Creek	$000		$431	$2,110	$2,173	$2,239	$2,306	$2,375	$2,446	$2,519	$2,595	$2,673	$2,753	$2,836	$2,921	$3,008	$3,099
CROD	$000		$2,873	$2,871	$2,873	$2,873	$2,871	$2,873	$2,870	$2,872	$2,873	$2,871	$2,874	$2,873	$2,870	$2,872	$2,873
Market	$000		$0	$1,577	$1,839	$2,113	$2,400	$2,699	$1,314	$1,599	$1,930	$2,285	$2,660	$3,057	$1,513	$1,912	$2,340
LM 6000	$000	$200k/yr (2012$) per unit for major maint.	$0	$0	$0	$0	$0	$0	$261	$269	$277	$285	$294	$303	$623	$642	$661
Combined Cycle	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other	$000		$40	$41	$42	$44	$45	$46	$48	$49	$51	$52	$54	$55	$57	$59	$61
Variable Costs (Excluding Fuel)-Total	**$000**		**$81,774**	**$89,145**	**$96,062**	**$103,985**	**$105,731**	**$111,927**	**$116,646**	**$124,569**	**$132,815**	**$142,656**	**$150,602**	**$144,243**	**$136,498**	**$144,422**	**$152,463**
SLP 1, 2, 3	$000		$31	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SLP 4	$000		$26	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cascade Creek	$000		$41	$54	$58	$64	$65	$74	$81	$85	$99	$109	$127	$137	$149	$174	$205
CROD	$000		$80,035	$86,415	$92,657	$100,106	$101,271	$106,620	$111,159	$118,085	$124,835	$133,338	$139,977	$131,541	$122,400	$127,950	$134,131
Market	$000		$1,642	$2,676	$3,348	$3,815	$4,395	$5,233	$5,130	$6,123	$7,573	$8,877	$10,108	$12,132	$13,124	$15,370	$17,060
LM 6000	$000		$0	$0	$0	$0	$0	$0	$276	$276	$307	$332	$389	$434	$826	$928	$1,067
Combined Cycle	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Costs-Total	**$000**		**$2,279**	**$1,802**	**$1,891**	**$2,062**	**$2,109**	**$2,411**	**$3,648**	**$3,791**	**$4,326**	**$4,705**	**$5,440**	**$5,985**	**$7,796**	**$8,811**	**$9,952**
SLP 1, 2, 3	$000		$550	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SLP 4	$000		$444	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cascade Creek	$000		$1,285	$1,802	$1,891	$2,062	$2,109	$2,411	$2,527	$2,655	$3,075	$3,360	$3,881	$4,237	$4,473	$5,133	$5,853
LM6000	$000		$0	$0	$0	$0	$0	$0	$1,121	$1,136	$1,251	$1,346	$1,559	$1,748	$3,324	$3,677	$4,099
Combined Cycle	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Service-Total	**$000**		**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$7,805**	**$7,805**	**$7,805**	**$7,805**	**$7,805**	**$7,805**	**$16,857**	**$16,857**	**$16,857**
SLP	$000																
LM6000	$000		$0	$0	$0	$0	$0	$0	$7,805	$7,805	$7,805	$7,805	$7,805	$7,805	$16,857	$16,857	$16,857
Combined Cycle	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Gas System	$000																
TOTAL COSTS	**$000**		**$95,897**	**$97,547**	**$104,881**	**$113,315**	**$115,462**	**$122,331**	**$135,038**	**$143,472**	**$152,671**	**$163,332**	**$172,480**	**$167,157**	**$169,135**	**$178,582**	**$188,305**

SUMMARY OF COSTS			2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Fixed Costs-Total	**$000**		**$9,599**	**$11,482**	**$11,826**	**$12,181**	**$12,546**	**$12,923**	**$13,311**	**$13,710**	**$14,121**	**$14,545**	**$15,409**	**$16,508**	**$17,665**	**$18,884**	**$20,167**
SLP 1, 2, 3	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SLP 4	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cascade Creek	$000		$3,192	$3,287	$3,386	$3,488	$3,592	$3,700	$3,811	$3,925	$4,043	$4,164	$4,289	$4,418	$4,550	$4,687	$4,828
CROD	$000		$2,871	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Market	$000		$2,793	$0	$0	$0	$0	$0	$0	$0	$0	$0	$428	$1,077	$1,772	$2,514	$3,306
LM 6000	$000	$200k/yr (2012$) per unit for major maint.	$681	$701	$722	$744	$766	$789	$813	$838	$863	$889	$915	$943	$971	$1,000	$1,030
Combined Cycle	$000		$0	$7,429	$7,652	$7,881	$8,118	$8,361	$8,612	$8,870	$9,137	$9,411	$9,693	$9,984	$10,283	$10,592	$10,909
Other	$000		$62	$64	$66	$68	$70	$72	$74	$77	$79	$81	$84	$86	$89	$92	$94
Variable Costs (Excluding Fuel)-Total	**$000**		**$163,158**	**$38,325**	**$40,952**	**$43,147**	**$45,662**	**$48,735**	**$52,815**	**$56,625**	**$61,095**	**$65,800**	**$70,956**	**$76,384**	**$81,981**	**$87,747**	**$94,239**
SLP 1, 2, 3	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SLP 4	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cascade Creek	$000		$230	$270	$285	$304	$325	$346	$366	$383	$403	$427	$454	$479	$510	$539	$575
CROD	$000		$142,553	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Market	$000		$19,173	$28,218	$30,384	$32,050	$34,021	$36,554	$40,138	$43,388	$47,299	$51,403	$55,920	$60,688	$65,589	$70,613	$76,330
LM 6000	$000		$1,203	$1,854	$1,954	$2,076	$2,221	$2,363	$2,495	$2,612	$2,745	$2,902	$3,097	$3,267	$3,479	$3,669	$3,917
Combined Cycle	$000		$0	$7,983	$8,330	$8,717	$9,093	$9,471	$9,816	$10,242	$10,647	$11,069	$11,485	$11,951	$12,404	$12,927	$13,418
Other	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Costs-Total	**$000**		**$10,954**	**$86,994**	**$91,569**	**$95,119**	**$98,615**	**$103,127**	**$108,399**	**$114,389**	**$120,433**	**$126,955**	**$133,811**	**$141,085**	**$148,748**	**$157,086**	**$165,739**
SLP 1, 2, 3	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SLP 4	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cascade Creek	$000		$6,433	$7,732	$8,211	$8,669	$9,192	$9,792	$10,461	$11,079	$11,776	$12,602	$13,557	$14,448	$15,556	$16,627	$17,951
LM6000	$000		$4,521	$6,894	$7,315	$7,695	$8,144	$8,666	$9,246	$9,782	$10,391	$11,104	$11,977	$12,770	$13,741	$14,648	$15,803
Combined Cycle	$000		$0	$72,369	$76,043	$78,756	$81,279	$84,669	$88,692	$93,528	$98,267	$103,249	$108,277	$113,867	$119,451	$125,811	$131,985
Debt Service-Total	**$000**		**$16,857**	**$63,321**	**$63,321**	**$63,321**	**$63,321**	**$63,321**	**$63,321**	**$63,321**	**$63,321**	**$63,321**	**$63,321**	**$55,516**	**$55,516**	**$55,516**	**$55,516**
SLP	$000																
LM6000	$000		$16,857	$16,857	$16,857	$16,857	$16,857	$16,857	$16,857	$16,857	$16,857	$16,857	$16,857	$9,052	$9,052	$9,052	$9,052
Combined Cycle	$000		$0	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464
Gas System	$000																
TOTAL COSTS	**$000**		**$200,568**	**$200,122**	**$207,669**	**$213,768**	**$220,144**	**$228,106**	**$237,846**	**$248,045**	**$258,970**	**$270,621**	**$283,497**	**$289,493**	**$303,910**	**$319,234**	**$335,662**

NPV @ 6.0% ($000): $2,289,340

Scenario 2: Retire Silver Lake Plant Units 1, 2, and 3 in 2015 – Base Case

SUMMARY OF COSTS			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Fixed Costs-Total	**$000**		**$11,844**	**$11,620**	**$12,106**	**$12,609**	**$13,131**	**$13,675**	**$14,236**	**$14,823**	**$15,466**	**$16,138**	**$16,845**	**$17,581**	**$16,695**	**$17,465**	**$18,274**
SLP 1, 2, 3	$000		$603	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SLP 4	$000		$7,896	$8,133	$8,377	$8,629	$8,887	$9,154	$9,429	$9,712	$10,003	$10,303	$10,612	$10,930	$11,258	$11,596	$11,944
Cascade Creek	$000		$431	$444	$458	$471	$486	$500	$515	$531	$547	$563	$580	$597	$615	$634	$653
CROD	$000		$2,873	$2,871	$2,873	$2,873	$2,871	$2,873	$2,870	$2,872	$2,873	$2,871	$2,874	$2,873	$2,870	$2,872	$2,873
Market	$000		$0	$130	$356	$592	$841	$1,102	$1,374	$1,660	$1,993	$2,349	$2,726	$3,124	$1,582	$1,983	$2,413
LM 6000	$000	$200k/yr (2012$) per unit for major maint.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$312	$321	$331
Combined Cycle	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other	$000		$40	$41	$42	$44	$45	$46	$48	$49	$51	$52	$54	$55	$57	$59	$61
Variable Costs (Excluding Fuel)-Total	**$000**		**$81,774**	**$88,708**	**$95,482**	**$103,362**	**$105,136**	**$111,283**	**$116,750**	**$124,678**	**$132,860**	**$142,728**	**$150,722**	**$144,258**	**$136,545**	**$144,644**	**$152,619**
SLP 1, 2, 3	$000		$31	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SLP 4	$000		$26	$42	$45	$52	$53	$62	$70	$70	$79	$85	$101	$115	$78	$84	$94
Cascade Creek	$000		$41	$50	$54	$60	$62	$70	$79	$83	$97	$106	$124	$135	$149	$174	$204
CROD	$000		$80,035	$86,415	$92,657	$100,106	$101,338	$106,620	$111,159	$118,085	$124,835	$133,338	$139,977	$131,541	$122,400	$128,229	$134,131
Market	$000		$1,642	$2,201	$2,726	$3,145	$3,682	$4,531	$5,442	$6,440	$7,849	$9,198	$10,519	$12,466	$13,405	$15,575	$17,520
LM 6000	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$513	$583	$671
Combined Cycle	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Costs-Total	**$000**		**$2,279**	**$2,297**	**$2,468**	**$2,738**	**$2,839**	**$3,236**	**$3,633**	**$3,752**	**$4,307**	**$4,682**	**$5,463**	**$6,068**	**$7,808**	**$8,786**	**$9,922**
SLP 1, 2, 3	$000		$550	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SLP 4	$000		$444	$711	$771	$874	$893	$1,037	$1,167	$1,155	$1,294	$1,398	$1,650	$1,868	$1,264	$1,345	$1,509
Cascade Creek	$000		$1,285	$1,586	$1,697	$1,864	$1,946	$2,200	$2,466	$2,598	$3,013	$3,284	$3,813	$4,200	$4,478	$5,131	$5,838
LM6000	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,066	$2,309	$2,576
Combined Cycle	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Service-Total	**$000**		**$4,536**	**$4,536**	**$4,536**	**$4,536**	**$4,536**	**$4,536**	**$4,536**	**$4,536**	**$4,536**	**$4,536**	**$4,536**	**$4,536**	**$13,588**	**$13,588**	**$13,588**
SLP	$000		$4,536	$4,536	$4,536	$4,536	$4,536	$4,536	$4,536	$4,536	$4,536	$4,536	$4,536	$4,536	$4,536	$4,536	$4,536
LM6000	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,052	$9,052	$9,052
Combined Cycle	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Gas System	$000																
TOTAL COSTS	**$000**		**$100,433**	**$107,160**	**$114,593**	**$123,245**	**$125,641**	**$132,730**	**$139,155**	**$147,790**	**$157,169**	**$168,084**	**$177,566**	**$172,442**	**$174,636**	**$184,483**	**$194,403**

SUMMARY OF COSTS			2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Fixed Costs-Total	**$000**		**$19,116**	**$21,208**	**$21,844**	**$22,499**	**$23,174**	**$23,869**	**$24,585**	**$25,323**	**$26,083**	**$26,865**	**$28,195**	**$29,677**	**$31,229**	**$32,854**	**$34,555**
SLP 1, 2, 3	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SLP 4	$000		$12,302	$12,671	$13,052	$13,443	$13,846	$14,262	$14,690	$15,130	$15,584	$16,052	$16,533	$17,029	$17,540	$18,066	$18,608
Cascade Creek	$000		$672	$692	$713	$735	$757	$779	$803	$827	$852	$877	$903	$931	$958	$987	$1,017
CROD	$000		$2,871	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Market	$000		$2,867	$0	$0	$0	$0	$0	$0	$0	$0	$0	$524	$1,176	$1,872	$2,617	$3,411
LM 6000	$000	$200k/yr (2012$) per unit for major maint.	$340	$351	$361	$372	$383	$395	$407	$419	$431	$444	$458	$471	$485	$500	$515
Combined Cycle	$000		$0	$7,429	$7,652	$7,881	$8,118	$8,361	$8,612	$8,870	$9,137	$9,411	$9,693	$9,984	$10,283	$10,592	$10,909
Other	$000		$62	$64	$66	$68	$70	$72	$74	$77	$79	$81	$84	$86	$89	$92	$94
Variable Costs (Excluding Fuel)-Total	**$000**		**$163,380**	**$38,357**	**$40,967**	**$43,189**	**$45,725**	**$48,816**	**$52,818**	**$56,575**	**$60,937**	**$65,577**	**$70,650**	**$75,940**	**$81,391**	**$86,727**	**$93,013**
SLP 1, 2, 3	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SLP 4	$000		$108	$208	$220	$234	$250	$266	$282	$296	$312	$331	$354	$375	$401	$567	$606
Cascade Creek	$000		$228	$270	$285	$303	$324	$345	$365	$382	$403	$426	$454	$480	$512	$541	$579
CROD	$000		$142,553	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Market	$000		$19,744	$28,847	$31,029	$32,767	$34,810	$37,410	$40,952	$44,187	$48,028	$52,114	$56,606	$61,288	$66,103	$71,074	$76,677
LM 6000	$000		$747	$1,064	$1,118	$1,184	$1,264	$1,342	$1,420	$1,483	$1,560	$1,649	$1,763	$1,858	$1,982	$1,629	$1,743
Combined Cycle	$000		$0	$7,968	$8,315	$8,701	$9,077	$9,454	$9,800	$10,227	$10,634	$11,056	$11,473	$11,939	$12,393	$12,916	$13,409
Other	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Costs-Total	**$000**		**$10,916**	**$87,233**	**$91,785**	**$95,340**	**$98,843**	**$103,331**	**$108,611**	**$114,567**	**$120,620**	**$127,104**	**$133,944**	**$141,198**	**$148,852**	**$157,427**	**$166,048**
SLP 1, 2, 3	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SLP 4	$000		$1,714	$3,298	$3,471	$3,675	$3,901	$4,134	$4,352	$4,549	$4,780	$5,042	$5,370	$5,665	$6,020	$8,473	$9,011
Cascade Creek	$000		$6,393	$7,749	$8,227	$8,669	$9,175	$9,764	$10,449	$11,070	$11,791	$12,623	$13,601	$14,516	$15,657	$16,740	$18,104
LM6000	$000		$2,809	$3,957	$4,186	$4,386	$4,633	$4,920	$5,262	$5,557	$5,907	$6,309	$6,816	$7,263	$7,830	$6,502	$7,032
Combined Cycle	$000		$0	$72,230	$75,900	$78,610	$81,133	$84,514	$88,548	$93,391	$98,143	$103,131	$108,157	$113,753	$119,344	$125,711	$131,902
Debt Service-Total	**$000**		**$13,588**	**$60,052**	**$60,052**	**$60,052**	**$60,052**	**$55,516**	**$55,516**	**$55,516**	**$55,516**	**$55,516**	**$55,516**	**$55,516**	**$55,516**	**$55,516**	**$55,516**
SLP	$000		$4,536	$4,536	$4,536	$4,536	$4,536										
LM6000	$000		$9,052	$9,052	$9,052	$9,052	$9,052	$9,052	$9,052	$9,052	$9,052	$9,052	$9,052	$9,052	$9,052	$9,052	$9,052
Combined Cycle	$000		$0	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464
Gas System	$000																
TOTAL COSTS	**$000**		**$207,000**	**$206,850**	**$214,648**	**$221,080**	**$227,793**	**$231,533**	**$241,531**	**$251,981**	**$263,156**	**$275,062**	**$288,305**	**$302,331**	**$316,987**	**$332,524**	**$349,133**

NPV @ 6.0% ($000): $2,385,414

Scenario 3: No Retirements – Base Case

SUMMARY OF COSTS		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Fixed Costs-Total	**$000**	**$11,844**	**$12,111**	**$12,390**	**$12,676**	**$12,968**	**$13,272**	**$13,582**	**$14,048**	**$14,675**	**$15,331**	**$16,022**	**$16,741**	**$17,494**	**$18,287**	**$19,119**
SLP 1, 2, 3	$000	$603	$621	$639	$659	$678	$699	$720	$741	$763	$786	$810	$834	$859	$885	$912
SLP 4	$000	$7,896	$8,133	$8,377	$8,629	$8,887	$9,154	$9,429	$9,712	$10,003	$10,303	$10,612	$10,930	$11,258	$11,596	$11,944
Cascade Creek	$000	$431	$444	$458	$471	$486	$500	$515	$531	$547	$563	$580	$597	$615	$634	$653
CROD	$000	$2,873	$2,871	$2,873	$2,873	$2,871	$2,873	$2,870	$2,872	$2,873	$2,871	$2,874	$2,873	$2,870	$2,872	$2,873
Market	$000	$0	$0	$0	$0	$0	$0	$0	$143	$439	$755	$1,092	$1,450	$1,834	$2,241	$2,677
LM 6000	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Combined Cycle	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other	$000	$40	$41	$42	$44	$45	$46	$48	$49	$51	$52	$54	$55	$57	$59	$61
Variable Costs (Excluding Fuel)-Total	**$000**	**$81,774**	**$88,577**	**$95,228**	**$103,183**	**$104,883**	**$110,985**	**$116,415**	**$124,265**	**$132,349**	**$142,150**	**$150,147**	**$143,664**	**$136,619**	**$144,785**	**$152,985**
SLP 1, 2, 3	$000	$31	$32	$36	$41	$42	$50	$58	$57	$67	$72	$86	$96	$111	$123	$140
SLP 4	$000	$26	$29	$32	$37	$40	$48	$55	$54	$63	$68	$80	$94	$105	$116	$128
Cascade Creek	$000	$41	$47	$51	$56	$59	$67	$76	$81	$95	$103	$120	$130	$148	$172	$200
CROD	$000	$80,035	$86,415	$92,657	$100,157	$101,338	$106,620	$111,159	$118,085	$124,835	$133,338	$139,977	$131,541	$122,400	$128,229	$134,131
Market	$000	$1,642	$2,055	$2,452	$2,891	$3,405	$4,200	$5,066	$5,987	$7,290	$8,569	$9,884	$11,803	$13,855	$16,144	$18,386
LM 6000	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Combined Cycle	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Costs-Total	**$000**	**$2,279**	**$2,513**	**$2,749**	**$3,062**	**$3,192**	**$3,735**	**$4,263**	**$4,357**	**$5,076**	**$5,468**	**$6,384**	**$7,110**	**$8,089**	**$9,074**	**$10,162**
SLP 1, 2, 3	$000	$550	$564	$633	$715	$727	$875	$1,011	$987	$1,153	$1,226	$1,462	$1,644	$1,896	$2,075	$2,340
SLP 4	$000	$444	$488	$540	$629	$665	$799	$921	$896	$1,035	$1,114	$1,303	$1,517	$1,699	$1,865	$2,053
Cascade Creek	$000	$1,285	$1,461	$1,577	$1,717	$1,799	$2,060	$2,331	$2,473	$2,888	$3,127	$3,619	$3,948	$4,494	$5,134	$5,769
LM6000	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Combined Cycle	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Service-Total	**$000**	**$6,996**	**$6,996**	**$6,996**	**$6,996**	**$6,996**	**$6,996**	**$6,996**	**$6,996**	**$6,996**	**$6,996**	**$6,996**	**$6,996**	**$6,996**	**$6,996**	**$6,996**
SLP	$000	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996	$6,996
LM6000	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Combined Cycle	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Gas System	$000															
TOTAL COSTS	**$000**	**$102,893**	**$110,197**	**$117,362**	**$125,916**	**$128,039**	**$134,988**	**$141,255**	**$149,665**	**$159,097**	**$169,944**	**$179,549**	**$174,510**	**$169,198**	**$179,142**	**$189,262**

SUMMARY OF COSTS		2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Fixed Costs-Total	**$000**	**$19,986**	**$21,824**	**$22,479**	**$23,153**	**$23,848**	**$24,563**	**$25,300**	**$26,059**	**$26,841**	**$27,900**	**$29,347**	**$30,861**	**$32,447**	**$34,107**	**$35,844**
SLP 1, 2, 3	$000	$939	$967	$996	$1,026	$1,057	$1,089	$1,121	$1,155	$1,189	$1,225	$1,262	$1,300	$1,339	$1,379	$1,420
SLP 4	$000	$12,302	$12,671	$13,052	$13,443	$13,846	$14,262	$14,690	$15,130	$15,584	$16,052	$16,533	$17,029	$17,540	$18,066	$18,608
Cascade Creek	$000	$672	$692	$713	$735	$757	$779	$803	$827	$852	$877	$903	$931	$958	$987	$1,017
CROD	$000	$2,871	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Market	$000	$3,139	$0	$0	$0	$0	$0	$0	$0	$0	$254	$871	$1,532	$2,237	$2,991	$3,795
LM 6000	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Combined Cycle	$000	$0	$7,429	$7,652	$7,881	$8,118	$8,361	$8,612	$8,870	$9,137	$9,411	$9,693	$9,984	$10,283	$10,592	$10,909
Other	$000	$62	$64	$66	$68	$70	$72	$74	$77	$79	$81	$84	$86	$89	$92	$94
Variable Costs (Excluding Fuel)-Total	**$000**	**$163,897**	**$38,821**	**$41,332**	**$43,632**	**$46,276**	**$49,362**	**$53,161**	**$56,698**	**$60,771**	**$65,225**	**$70,227**	**$75,353**	**$80,636**	**$86,178**	**$92,307**
SLP 1, 2, 3	$000	$147	$245	$260	$276	$294	$312	$332	$362	$383	$425	$454	$481	$514	$543	$582
SLP 4	$000	$144	$246	$259	$274	$292	$310	$329	$346	$366	$388	$415	$439	$470	$495	$531
Cascade Creek	$000	$227	$275	$290	$308	$328	$349	$371	$384	$406	$422	$451	$476	$509	$539	$577
CROD	$000	$142,553	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Market	$000	$20,826	$30,125	$32,242	$34,109	$36,324	$38,974	$42,360	$45,405	$49,001	$52,949	$57,449	$62,030	$66,760	$71,695	$77,218
LM 6000	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Combined Cycle	$000	$0	$7,930	$8,281	$8,665	$9,039	$9,417	$9,769	$10,202	$10,615	$11,041	$11,458	$11,927	$12,382	$12,907	$13,400
Other	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Costs-Total	**$000**	**$11,191**	**$87,915**	**$92,544**	**$96,129**	**$99,658**	**$104,195**	**$109,598**	**$115,661**	**$121,858**	**$128,417**	**$135,266**	**$142,561**	**$150,258**	**$158,483**	**$167,135**
SLP 1, 2, 3	$000	$2,441	$4,156	$4,378	$4,629	$4,907	$5,195	$5,500	$5,978	$6,304	$6,999	$7,451	$7,852	$8,361	$8,783	$9,368
SLP 4	$000	$2,297	$3,886	$4,081	$4,297	$4,548	$4,806	$5,082	$5,315	$5,598	$5,910	$6,296	$6,631	$7,058	$7,406	$7,893
Cascade Creek	$000	$6,453	$7,984	$8,488	$8,916	$9,411	$10,004	$10,753	$11,207	$11,989	$12,521	$13,500	$14,436	$15,599	$16,677	$18,062
LM6000	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Combined Cycle	$000	$0	$71,888	$75,596	$78,288	$80,792	$84,189	$88,263	$93,161	$97,967	$102,987	$108,019	$113,642	$119,240	$125,617	$131,813
Debt Service-Total	**$000**	**$6,996**	**$53,460**	**$53,460**	**$53,460**	**$53,460**	**$46,464**	**$46,464**	**$46,464**	**$46,464**	**$46,464**	**$46,464**	**$46,464**	**$46,464**	**$46,464**	**$46,464**
SLP	$000	$6,996	$6,996	$6,996	$6,996	$6,996										
LM6000	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Combined Cycle	$000	$0	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464	$46,464
Gas System	$000															
TOTAL COSTS	**$000**	**$202,069**	**$202,019**	**$209,814**	**$216,374**	**$223,242**	**$224,584**	**$234,524**	**$244,882**	**$255,934**	**$268,007**	**$281,304**	**$295,240**	**$309,805**	**$325,232**	**$341,750**

NPV @ 6.0% ($000): $2,373,307

APPENDIX D

SENSITIVITY ANALYSIS

Variables and Factors

Interest Rate

Triangular Distribution

minimum value:	4.50%
most likely value:	4.50%
maximum value:	6.50%

Coal Escalation

Triangular Distribution

minimum value:	2.50%
most likely value:	2.50%
maximum value:	7.50%

Natural Gas Price 2015

Triangular Distribution

minimum value:	$4.30
most likely value:	$4.64 (taken from natural gas forecast)
maximum value:	$6.30

Market $/MW-year 2015

Triangular Distribution

minimum value:	-20% of most likely value
most likely value:	$32.31 (taken from forecast)
maximum value:	+20% of most likely value

Capital/Debt (LM6000 & CC)

Triangular Distribution

minimum value:	-20% of most likely value
most likely value:	projected debt service payment
maximum value:	+20% of most likely value

Capital for SLP Modifications for 114

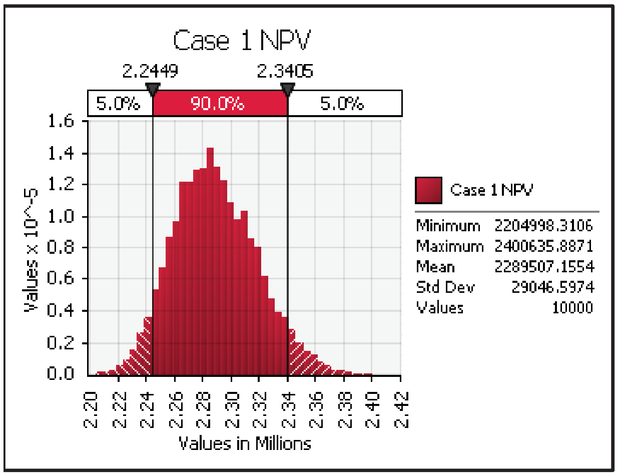
Triangular Distribution

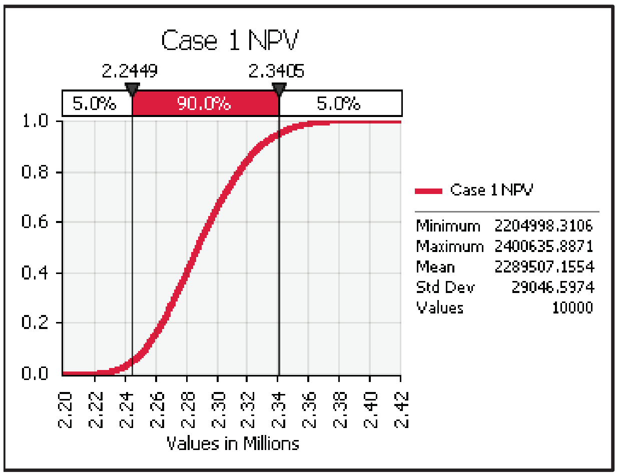
minimum value:	-30% of projected capital cost
most likely value:	-15% of projected capital cost
maximum value:	+20% of projected capital cost

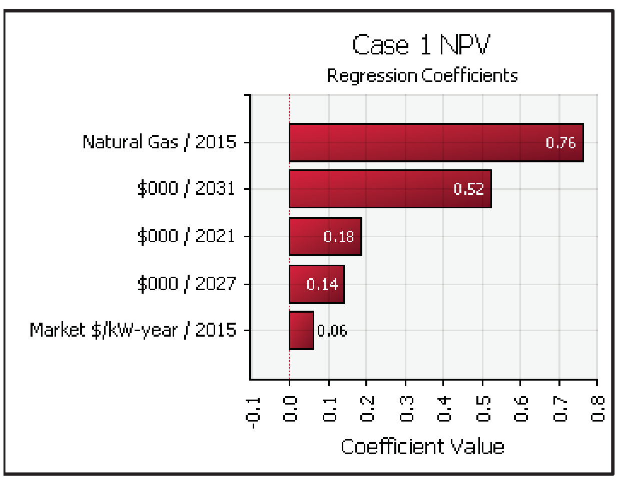
@RISK Output Report for Case 1 NPV

Performed By: sworrall

Date: Wednesday, July 25, 2012 3:41:46 PM







Simulation Summary Information	
Workbook Name	Case 1.xlsx
Number of Simulations	1
Number of Iterations	10000
Number of Inputs	7
Number of Outputs	1
Sampling Type	Latin Hypercube
Simulation Start Time	7/25/12 15:41:31
Simulation Duration	00:00:10
Random # Generator	Mersenne Twister
Random Seed	713722526

Summary Statistics for Case 1 NPV

Statistics		**Percentile**	
Minimum	$2,204,998	**5%**	$2,244,925
Maximum	$2,400,636	**10%**	$2,253,411
Mean	$2,289,507	**15%**	$2,259,165
Std Dev	$29,047	**20%**	$2,264,180
Variance	843704821.4	**25%**	$2,268,334
Skewness	0.291721332	**30%**	$2,272,425
Kurtosis	2.811740889	**35%**	$2,276,392
Median	$2,287,523	**40%**	$2,280,191
Mode	$2,283,567	**45%**	$2,283,845
Left X	$2,244,925	**50%**	$2,287,523
Left P	5%	**55%**	$2,291,272
Right X	$2,340,453	**60%**	$2,295,290
Right P	95%	**65%**	$2,299,351
Diff X	$95,528	**70%**	$2,304,230
Diff P	90%	**75%**	$2,309,503
#Errors	0	**80%**	$2,314,448
Filter Min	Off	**85%**	$2,320,596
Filter Max	Off	**90%**	$2,328,359
#Filtered	0	**95%**	$2,340,453

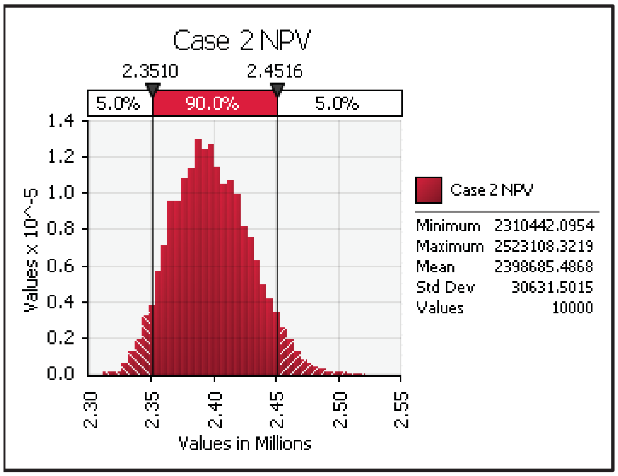
Regression and Rank Information for Case 1 NPV

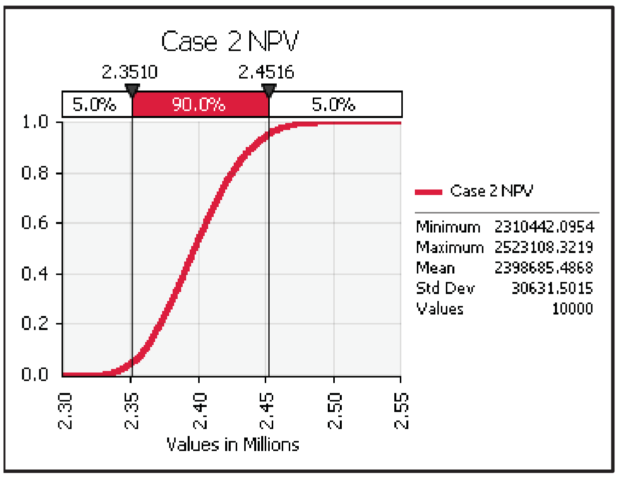
Rank	**Name**	**Regr**	**Corr**
1	Natural Gas / 2015	0.764	0.747
2	$000 / 2031	0.522	0.578
3	$000 / 2021	0.184	0.304
4	$000 / 2027	0.142	0.290
5	Market $/kW-year / 2015	0.059	0.057
6	Coal Ecalation / 2015	0.000	-0.018847174

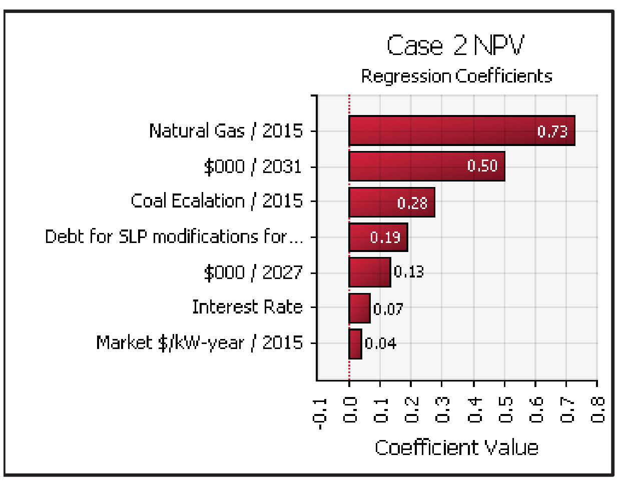
@RISK Output Report for Case 2 NPV

Performed By: sworrall

Date: Wednesday, July 25, 2012 3:43:30 PM







Simulation Summary Information	
Workbook Name	Case 2.xlsx
Number of Simulations	1
Number of Iterations	10000
Number of Inputs	7
Number of Outputs	1
Sampling Type	Latin Hypercube
Simulation Start Time	7/25/12 15:43:15
Simulation Duration	00:00:12
Random # Generator	Mersenne Twister
Random Seed	357534643

Summary Statistics for Case 2 NPV

Statistics		**Percentile**	
Minimum	$2,310,442	**5%**	$2,350,973
Maximum	$2,523,108	**10%**	$2,360,163
Mean	$2,398,685	**15%**	$2,366,310
Std Dev	$30,632	**20%**	$2,371,457
Variance	938288883.5	**25%**	$2,376,281
Skewness	0.253607631	**30%**	$2,380,702
Kurtosis	2.775518149	**35%**	$2,385,228
Median	$2,397,080	**40%**	$2,389,144
Mode	$2,405,891	**45%**	$2,392,960
Left X	$2,350,973	**50%**	$2,397,080
Left P	5%	**55%**	$2,400,991
Right X	$2,451,650	**60%**	$2,405,617
Right P	95%	**65%**	$2,409,910
Diff X	$100,677	**70%**	$2,414,661
Diff P	90%	**75%**	$2,419,423
#Errors	0	**80%**	$2,425,123
Filter Min	Off	**85%**	$2,431,456
Filter Max	Off	**90%**	$2,439,876
#Filtered	0	**95%**	$2,451,650

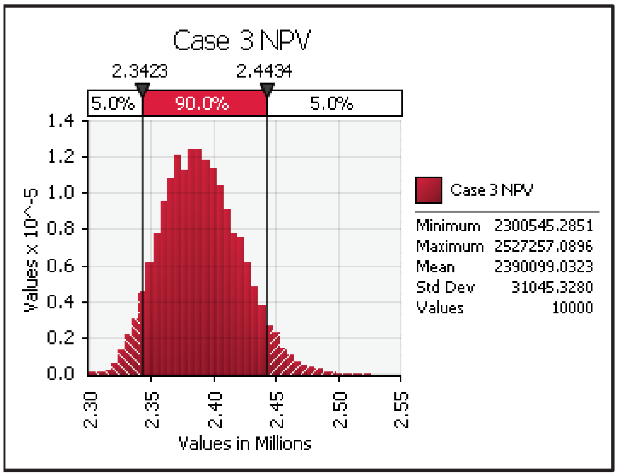
Regression and Rank Information for Case 2 NPV

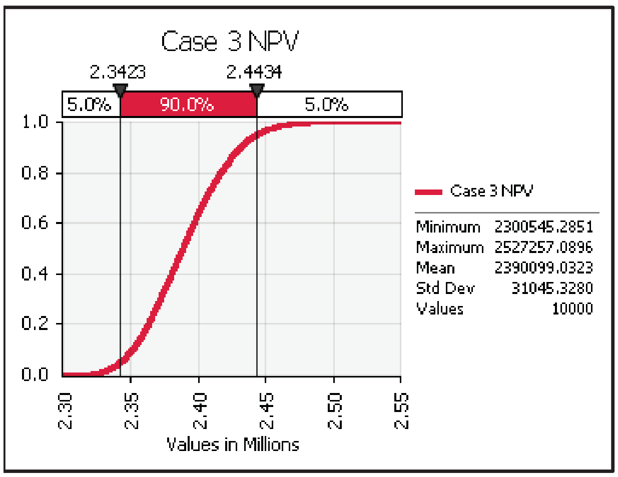
Rank	**Name**	**Regr**	**Corr**
1	Natural Gas / 2015	0.730	0.722
2	$000 / 2031	0.500	0.552
3	Coal Ecalation / 2015	0.275	0.254
4	Debt for SLP modifications for 114	0.189	0.198
5	$000 / 2027	0.134	0.269
6	Interest Rate	0.066	0.379
7	Market $/kW-year / 2015	0.040	0.040

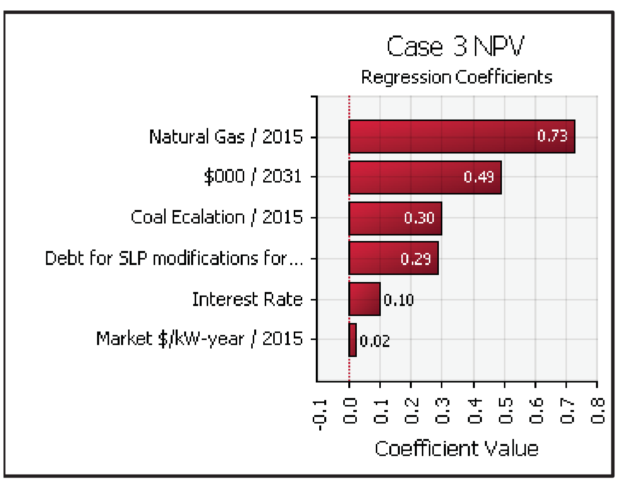
@RISK Output Report for Case 3 NPV

Performed By: sworrall

Date: Wednesday, July 25, 2012 3:44:37 PM







Simulation Summary Information	
Workbook Name	Case 3.xlsx
Number of Simulations	1
Number of Iterations	10000
Number of Inputs	6
Number of Outputs	1
Sampling Type	Latin Hypercube
Simulation Start Time	7/25/12 15:44:24
Simulation Duration	00:00:10
Random # Generator	Mersenne Twister
Random Seed	1842458120

Summary Statistics for Case 3 NPV

Statistics		**Percentile**	
Minimum	$2,300,545	**5%**	$2,342,322
Maximum	$2,527,257	**10%**	$2,351,118
Mean	$2,390,099	**15%**	$2,357,669
Std Dev	$31,045	**20%**	$2,362,842
Variance	963812393.1	**25%**	$2,367,409
Skewness	0.286635546	**30%**	$2,371,775
Kurtosis	2.844102379	**35%**	$2,375,876
Median	$2,388,546	**40%**	$2,380,306
Mode	$2,394,631	**45%**	$2,384,332
Left X	$2,342,322	**50%**	$2,388,546
Left P	5%	**55%**	$2,392,581
Right X	$2,443,399	**60%**	$2,396,762
Right P	95%	**65%**	$2,401,091
Diff X	$101,076	**70%**	$2,405,879
Diff P	90%	**75%**	$2,410,911
#Errors	0	**80%**	$2,416,797
Filter Min	Off	**85%**	$2,423,391
Filter Max	Off	**90%**	$2,431,525
#Filtered	0	**95%**	$2,443,399

Regression and Rank Information for Case 3 NPV

Rank	**Name**	**Regr**	**Corr**
1	Natural Gas / 2015	0.727	0.715
2	$000 / 2031	0.492	0.530
3	Coal Ecalation / 2015	0.295	0.274
4	Debt for SLP modifications for 114	0.286	0.256
5	Interest Rate	0.099	0.363
6	Market $/kW-year / 2015	0.023	0.003