Legalectric, Inc.
Carol Overland **Attorney at Law, MN #254617**
Energy Consultant—Transmission, Power Plants, Nuclear Waste
overland@legalectric.org

1110 West Avenue
Red Wing, Minnesota 55066
612.227.8638

November 21, 2016

Eric Lipman
Administrative Law Judge eFiled & emailed: routecomments.oah@state.mn.us
Office of Administrative Hearings
P.O. Box 64620
St. Paul, MN 55164-0620

RE: **Overland Comment on Pipeline Routing**
OAH Docket: 8-2500-33180
PUC Docket G-011/GP-15-858

Dear Judge Lipman:

Enclosed please find Comments of Carol A. Overland, comments made as an individual, and not in the course of representing any client. These comments have been eFiled, emailed, and a paper copy of Comments and the marked route map is in the mail because the photos eFiled aren't very clear.

<u>Need for this project is precluded by CapX 2020 and RIGO transmission</u>

Because there is no Certificate of Need for this project, there is no prohibition of consideration of need by statute or rule. The prohibitions of consideration of need found in Minn. Stat. §§216E.02, Subd. 2 and 216E.03, Subd. 5, are not applicable to pipeline routing.

The purpose of the project is to provide fuel for the Rochester Public Utility (RPU) Westside Energy Station. The Westside Energy Station "will be capable of producing 47 megawatts of power which will be sold on the open market or used during peak energy times in the city."[1]
The Westside Energy Station was included as a resource in RPU's 2005 "*Report on the Electric Utility Baseline Strategy for 2005-2030 Electric Infrastructure*" (Report, Attachment A). The

[1] A New Generating Station for Rochester, KROC, online at: http://krocam.com/a-new-generating-station-for-rochester/

report recommendations include increased reliance on transmission and participation in the market for purchases and sales.[2] Directly related to this docket, the Report also recommended:

4. Consider taking options on approximately 100 acres of land within the RPU service territory near a high pressure gas line and transmission facilities under RPU control for installation of future combustion turbine capacity.

5. Develop a parallel path project to accelerate installation of combustion turbine capacity required in the long term plan to maintain system reliability should the selected transmission upgrade project be delayed.

7. Around 2014, assuming that new generation is required in accordance with the long range plan and that generation has not been installed in connection with the transmission issue, begin the process for installation of approximately 50 to 100 MW of natural gas-fired generation for an in service date of 2018. The generation should be low capital cost with as low an operating cost as is consistent with expected operating capacity factors.

Report, p. S-21.

Gas combustion generation was discussed in more detail in the report, noting that "RPU could develop gas-fired units within its service territory without the need for partners due to the lower effect of economies of scale." Id., p. III-5.

"Need" for electricity in the Rochester area was a primary consideration in the need determination for CapX 2020, based on forecasted increase in demand that has proven grossly overstated. CapX 2020 Recommendation. At the time of the CapX Certificate of Need hearing, there several 161kV lines, known as the RIGO transmission project, proposed to be built in the area, which, again based on the grossly overstated demand projections, would "adequately serve the area load until 2015."[3] Further, Dairyland reconductored another 161kV line in the area between Rochester and Adams, and CapX Applicants admitted that "[w]ith the reconductoring and the installation of the RIGO lines, the system could reliably serve load to 468 MW, a level expected to be reached in approximately 2018."[4] Intervenors and Commerce OES "correctly pointed out that if the level of generation in Rochester is maintained, the RIGO lines will provide reliability service in Rochester until 2026…"[5]

The CapX 2020 Certificate of Need recommendation was based on Applicant testimony that "assumed that current Rochester generation would be going down as facilities ar scheduled to retire. In conducting its analysis, the Applicants assumed that there would be no local generation to serve load in 2020."[6] It was also noted that "RPU has plans to

[2] Report, Recommendations, p. S-21-23; see also IV-8-9.
[3] CapX 2020 Need Recommendation, FoF 203 (attached).
[4] Id., FoF 204.
[5] Id., FoF 209.
[6] Id., FoF 207.

retire its current generation in the Rochester area by 2015 (a reduction of approximately 67 MW) and to seek permits for a new West Side substation, connection to new 161 kV lines. RPU is also considering adding gas generation, although no specific proposal was included."[7]

However, neither the planned RPU Westside Energy Station nor the RIGO lines and the many megawatts that they would provide for Rochester were taken into account because permits had not been applied for at the time of the CapX 2020 Certificate of Need hearing:

- RPU is also considering adding gas generation, although no specific proposal was included. None of the potential projects have received permits or have a date certain for coming into service.[8]

- At the time that the record in this proceeding closed, the application for a certificate of need for the RIGO lines had not been filed and there were no specific plans for new generation.[9]

Note that owners of the RIGO transmission lines and the Westside Energy Station were CapX 2020 applicants.

Since that time, 2008, the CapX 2020 transmission projects, including the Hampton-Rochester-La Crosse 345 kV transmission line with the Chester 161 kV line and all the RIGO transmission projects have been applied for, permitted, and built. As the CapX 2020 Recommendation notes, "[a]lthough installation of RIGO would postpone the need for the La Crosse Project to serve Rochester load, the La Crosse Project will also provide alternative 345 kV support to Rochester that will meet its needs for many years."[10]

Those RIGO 161 kV transmission projects that would meet Rochester's needs for many years, plus the CapX 2020 345 kV transmission line, which would meet Rochester's needs for many, many more years, calls into question the need for the Westside Energy Station, and the need for this pipeline. Based on the Findings in the CapX 2020 proceeding, using grossly inflated demand forecasts, based on the actual demand curve over the last decade, and based on the existence of excess transmission capacity through construction of RIGO and CapX 2020 transmission, there is no demonstrated for the Westside Energy Station and this natural gas pipeline to fuel it.

<u>This project is proposed in unacceptable proximity to homes</u>

The Commission's criteria for routing of a pipeline "must include the existence of populated areas, consideration of local government land use laws including ordinances adopted under

[7] Id. FoF 208.
[8] Id., FoF 208.
[9] Id., FoF209.
[10] Id. FoF 209.

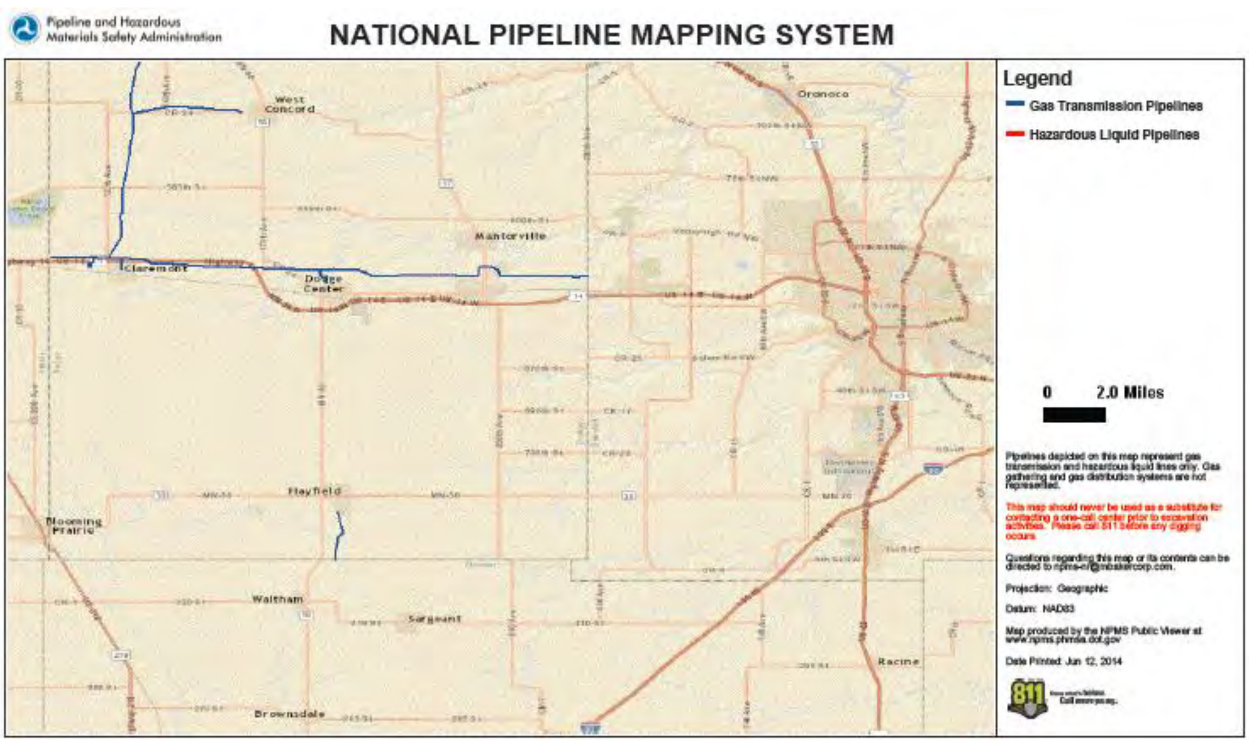
section 299J.05, and the impact of the proposed pipeline on the natural environment. Minn. Stat. §216G.02, Subd. 3(4). On the other hand:

> The pipeline routing permit supersedes and preempts all zoning, building, or land use rules, regulations, or ordinances promulgated by regional, county, local, and special purpose governments.

Id., Subd. 4.

This pipeline is proposed through established residential areas, rural areas with nearby homes, and areas of planned development, permitted and in the permitting process. The most disturbing aspect of this project is the proximity to homes.

Natural gas pipelines have been known to rupture. There have been two natural gas pipeline explosions recently in Alabama with fatal results. A large transmission pipeline travels through southern Minnesota through Kasson and Byron to Rochester:



In the City of Kasson, it was moved a few blocks north of its original location so that the City could build a school, it would not build the school adjacent to the pipeline! However, both Kasson and Byron have developed subdivisions surrounding the pipeline, and have platted lots over the pipeline easement! In the case of a client, the pipeline easement was fully within their back yard, and the closest edge of the easement was within 25 feet of their home. Learning that the natural gas transmission pipeline was so close robbed them of their use and enjoyment of their new home. They were unable to plant trees and other landscaping, were unable to place a shed in the back yard, were unable to put a fence around their back yard, and unable to garden, which was a primary purpose of the purchase of that home. Fortunately we were able to settle the issue, but landowners should not be put in the position of living in close proximity to a natural gas pipeline.

In this case, it's my hope that Olmsted County and Rochester will not permit and plat over this pipeline. However, there are planned developments, and there are existing homes and developments that could be affected, and it is important to preserve these landowners use and enjoyment of their property and not subject then to the uncertainty and risk of living next to a pipeline.

This pipeline is 5.1 miles of 16" pipeline operating at 400-475 psig, and 8.0 miles of 12" pipeline operating at 250-275 psi. *Safe Separation Distances from Natural Gas Transmission Pipelines*, Attachment C, and *A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines*, Attachment D, provide information and recommendations for pipeline distances from homes. For example, in *Safe Separation Distances from Natural Gas Transmission Pipelines*, a natural gas pipeline operating at 600 psi has a burn radius of just under 525 feet. *A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines* notes that a 12" pipeline at 600 psi has a hazard area radius of roughly 200 feet, and an 18" pipeline at 600 psi roughly 300 feet.

Looking at the maps provided in the Comparative Environmental Analysis, the proximity to homes is unacceptable. Page 1 through the top of page 4 show the 16' 400-475 psig pipeline, and continuing on page 4 through page 10 is the 12" pipeline at 250-275 psig. The maps, with a 500 foot route, within which a 50 foot easement would be set, show the following numbers of homes (see photos of maps, attached, hard copies via mail):

CEA Map Page – Residences…	Homes at or within 500 foot route width
Page 1	16" 400-475 psig – 3 homes within 250'
Page 2	16" 400-475 psig – 3 homes within 250'
Page 3	16" 400-475 psig – 4 homes within 250'
Page 4	16" 400-475 psig – 2 homes within 250'
Page 4 (other route)	16" 400-475 psig – 2 homes within 250'
Page 5	12" 250-275 psig – 5 homes within 250'
Page 6	12" 250-275 psig – 13 homes within 250"
Page 6 (other route)	12" 250-275 psig – 1 home within 250"
Page 6 (other route)	12" 250-275 psig – 2 homes within 250"
Page 7	12" 250-275 psig – 12+ homes within 250
Page 7 (other route)	12" 250-275 psig – 4 homes within 250
Page 7 (other route)	12" 250-275 psig – 2 homes within 250
Page 7 (other route)	12" 250-275 psig – 16+ homes within 250
Page 8	12" 250-275 psig – 30+ homes within 250
Page 9	12" 250-275 psig (none within route, subdivision nearby)
Page 10	12" 250-275 psig (none)

This project, if granted a route permit, should be routed in recognition of existing and planned land use, sufficiently distant from homes and subdivisions to not interfere with land uses, and to not interfere with landowners use and enjoyment of their property.

<u>This pipeline is to serve the Westside Energy Station, for a private market purpose</u>

The power of eminent domain is not available for a private purpose project. The sales and delivery via this pipeline are to one entity, the Westside Energy Station. As noted above, the Westside Energy Station electricity is destined for market.[11] That is a private purpose. This project should not be granted the power of eminent domain. This has been held in recent court decisions regarding pipelines specifically. For example, in Kinder Morgan Utopia v. PDB Farms of Wood County, LLC, the court found the pipeline was for a single customer for private purpose:

> The petroleum products are to pass through this pipeline, connecting with an existing pipeline at the Michigan-Ohio border, which travels up to Canada near the city of Windsor, to a private business engaged in the manufacturing of plastic products…
>
> … The hearing also established that Kinder Morgan had only one committed shipper that is paying the cost of the construction of the pipeline, and the user, Nova Chemicals, will solely utilize the pipeline. Kinder Morgan alleges that the pipeline would be available to "walk-up shippers" who are third parties who could use the capacity of the Utopia Pipeline in the future. However, Kinder Morgan admits that there are no such users at this time…

Attachment E, *Kinder Morgan Utopia v. PDB Farms of Wood County, LLC*.[12] A similar result resulted in *Bluegrass Pipeline Company v. Kentuckians United to Restrain Eminent Domain*,[13] where a company serving a private need was denied the use of eminent domain. Attachment F. As with the Kinder Morgan case, there is no presumption of necessity, of need, and no Certificate of Need is required for this pipeline for this pipeline because it is 13.1 miles long, 1.9 miles short of the threshold for a Certificate of Need.

<u>Short version of comments</u>

- **Need for the pipeline and the natural gas it will deliver has not been demonstrated.**
- **Local land use and permitting must be considered in routing sufficient to protect landowners use and enjoyment of their property. This pipeline should not be, must not be, routed within 300 feet of any home or business.**

[11] A New Generating Station for Rochester, KROC, online at: http://krocam.com/a-new-generating-station-for-rochester/

[12] *Kinder Morgan Utopia v. PDB Farms of Wood County, LLC,* online at: http://legalectric.org/f/2016/10/KinderMorgan-v-PDB-Farms_2016CV0220.pdf

[13] *Bluegrass Pipeline Company v. Kentuckians United to Restrain Eminent Domain* online at: http://legalectric.org/f/2015/05/Kentucky_PipelineAppealsCourtDecision_NoEminentDomain.pdf

- **No eminent domain for a private purpose project**

Thank you for the opportunity to comment. If you have any questions or require further information, do not hesitate to contact me.

Very truly yours,

Carol A. Overland
Attorney at Law

Attachment A

Report on the Electric Utility Baseline Strategy for 2005-2030 Electric Infrastructure (selected)

Prepared for Rochester Public Utilities
June 2005

Report on the Electric Utility Baseline Strategy for 2005-2030 Electric Infrastructure

Prepared for

Rochester Public Utilities
Rochester, Minnesota

Project 34945

June 2005

Burns & McDonnell
SINCE 1898

Burns & McDonnell
SINCE 1898

June 15, 2005

Mr. Wally Schlink
Rochester Public Utilities
4000 E. River Rd. NE
Rochester, MN 55906-2813

RE: Baseline Electric Infrastructure Study
Rochester Public Utilities
Project 34945

Dear Mr. Schlink:

Burns & McDonnell was authorized to assist the Rochester Public Utilities (RPU) in its assessment of future requirements for its electrical infrastructure. The RPU desired a baseline assessment of its financial requirements over a study period to 2030. The assessment included the review of traditional resources associated with meeting RPU's projected demand and energy needs to develop a traditional resource expansion plan. The impacts which demand side and renewable options might have on the traditional plan were also included. The costs for several futures were modeled in a detailed financial model developed by RPU. The model allowed a detailed assessment of a variety of measures such as rates, average bills and debt requirements to be developed. These parameters were used to identify the more attractive future for RPU to pursue. This report provides the results of the assessment.

The assessment for RPU identified issues which need to be confronted within the time frame between now and 2015 and from 2016 to 2030. These periods were selected to coincide with the various options associated with the Silver Lake Plant capacity under the contract with the Minnesota Municipal Power Agency.

Conclusions and Recommendations

The results of this study indicate that the Silver Lake Plant Unit 4 should be kept in operation throughout the study period. The determination of the status of Units 1-3 depends on the cost of replacement capacity at the end of the MMPA contract.

With the above assumption on Silver Lake Unit 4, the RPU is not in need of significant resource expansion to meet its projected demand and energy requirements until approximately 2016. Prior to that date, RPU should rely on the market for seasonal purchases to make up any deficits. Post 2016, a mixture of market, gas and coal-fired resources provide the lowest cost evaluated plan.

The above conclusion on use of market capacity is tempered by the fact that RPU will have to correct the existing transmission limitations into the RPU service territory or add internal generation in order to regain previous levels of power supply reliability for its customers. The current limitations reduce the firm import of its supply from the Southern Minnesota Municipal Power Agency when the load in the area around RPU exceeds certain levels. These levels are being exceeded during an increasing number of hours per year. Therefore, reliance on the market for firm imports during the summer months is not considered prudent until the transmission limitation is removed.

Challenges which RPU will confront over the next ten years include environmental controls and upgrades to the Silver Lake Plant Unit 4 and potentially Units 1-3 to continue operation in compliance with expected environmental regulations. The investments in these units will help prolong the time when RPU will need replacement coal capacity.

RPU should pursue the aggressive demand side management reductions identified. The achievement of the estimated reductions will postpone the need for additional base load capacity.

Synopsis of Process

Burns & McDonnell developed the traditional resource plan by first reviewing the load projections prepared by RPU. The forecast allowed an assessment of the capacity and energy deficiencies associated with various futures. The primary variance in the futures was due to the assumptions used for the capacity at the Silver Lake Power Plant.

Resource expansion plans were developed which provided an assessment of the benefits of gas and coal-fired resource options. Participation in projects being developed in the region were considered along with resources that RPU could develop on its own. These options were reviewed on a net present value basis to determine the lower cost options.

Risk analysis was performed on the lower cost options. Assumptions were varied to determine their impact on the evaluation. Risk profiles of the probable net present values were determined. The report provides a complete description of the process and the results identified.

A variety of demand side options were considered to reduce the demand and energy needs of RPU. Benefit cost analysis was performed on the options to determine the attractiveness of the options from the utility rate payers, participant and society perspectives. This review was aided by input from a Citizen's Advisory group.

The estimated reductions in demand and energy requirements were removed from the forecast. The revised forecast was then used to assess the RPU renewable energy needs to meet the state renewable portfolio standard.

The various futures with and without the DSM and renewable impacts were modeled in the detailed financial forecast model. The results indicated that an aggressive DSM approach would provide benefits to RPU in delaying base load capacity.

Summary

The results of the infrastructure plan have identified the lower cost approaches to meeting the RPU demand and energy requirements to the year 2030 include a combination of market purchases, gas and coal-fired resource additions, ongoing modifications to the Silver Lake Plant and a variety of DSM programs. Renewable energy should be pursued from wind resources and the Olmstead Waste to Energy Facility biomass facility.

We look forward to discussing any aspect of this report with you at your convenience.

Sincerely,
BURNS & MCDONNELL

Jeff Greig
General Manager
Business & Technology Services

Kiah Harris
Project Manager

KH/pma

TABLE OF CONTENTS

APPENDICES

LIST OF TABLES

LIST OF FIGURES

Summary

The management of Rochester Public Utilities (RPU) is interested in developing a long range baseline infrastructure plan for the utility. The growth of the customer load will require acquisition of additional generation resources, potential modifications of existing resources and upgrades to the utility's local and the region's transmission systems. These projects will be competing for capital from the RPU. In order to minimize the investment in these areas, a long range plan is needed which provides a coordinated approach to resource expansion.

The approach taken by RPU was to develop a multi-phased approach to understanding these needs. The various phases include:

- Environmental modifications necessary at the Silver Lake Plant (SLP),
- Transmission upgrade studies for regional improvements,
- Review of traditional resource expansion alternatives,
- Review of demand side management and renewable alternatives.

This report provides information on the traditional generation resource planning undertaken to provide a baseline for comparing the demand side management (DSM) and renewable options and understanding how RPU intends to use the transmission system.

Being a municipal utility, RPU is responsible to the citizens of Rochester, who are the customers it serves. In order to understand the issues of importance to its customers, RPU has periodic customer satisfaction surveys performed. According to customer satisfaction research conducted by Morgan Marketing in 2001, keeping the price for electricity as low as possible and aggressively pursuing energy conservation and renewable generation strategies were ranked in order as the highest needs among 18 performance attributes.

The development of this plan recognizes those needs. Phase I herein reviewed the needs and traditional approaches to meeting the resource needs of RPU's customers in a low cost manner in accordance with reliability standards in the industry. It established a baseline from which to measure potential impacts of renewable energy sources and customer modifications to consumption. The Phase II effort reviewed conservation, demand side management and renewable options to be integrated into the RPU system which could reduce or eliminate the need for the addition of the traditional resources.

The development of the long range baseline infrastructure plan (Plan) will incorporate aspects of an integrated resource plan and a financial plan for the utility. Issues which the Plan will cover include, but are not limited to:

- Basic generation and transmission resource expansion, including additional internal generation and participation in regional generation;
- Consideration of the renewable portfolio requirements of Minnesota;
- Demand side management, customer involvement in managing loads;
- Estimated costs for the utility and financial model development.

The analysis required to support the decisions on the traditional resource options is the subject of Parts II, III and IV in this report. The assessment of renewable and demand side management issues is the subject of Part V. Part VI is a discussion of the detailed financial forecast for a variety of futures. RPU retained Burns & McDonnell to assist RPU in the development of the Plan. The first effort was to analyze the power supply needs to the 2030 time frame in order to identify any longer term issues which could impact shorter term decisions.

The review of these issues was divided into two major time periods. The periods were from 2005 to 2015 and from 2016 to 2030. These time frames were developed to coincide with the termination of the Minnesota Municipal Power Agency (MMPA) sales contract, at which time the RPU will regain the complete output of the SLP for its own use.

Current Conditions

Generation Resources

RPU projected the demand and energy growth for the study horizon to be 2.7 percent. This compares to an historic growth of 3.5 percent for the past 15 years. It is expected that the RPU load factor will remain relatively constant over the study horizon.

The capacity and energy resources for RPU include:

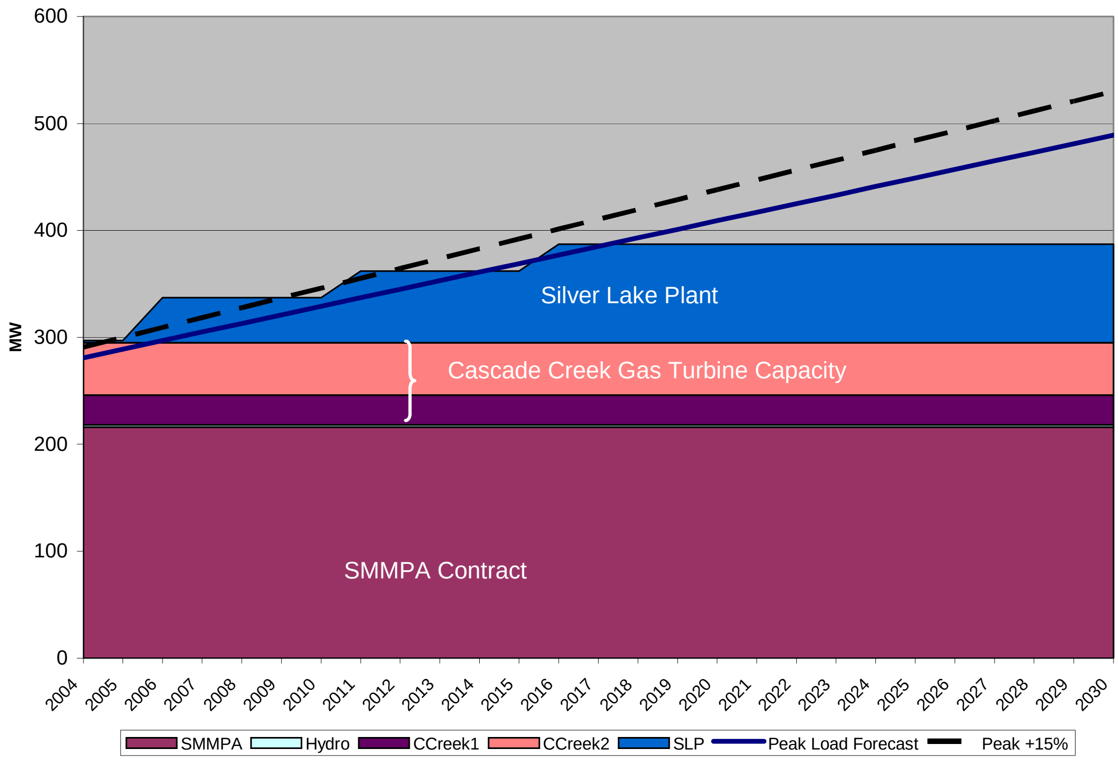
- Contract with Southern Minnesota Municipal Power Agency (SMMPA),
- Combustion Turbines at Cascade Creek,
- Steam units at the Silver Lake Power Plant,
- Zumbro Hydro Facility.

The available capacity and load forecast are shown in Figure S-1. The figure also includes the 15 percent reserve margin required by Mid-Continent Area Power Pool (MAPP) on RPU load above the Contract Rate of Demands (CROD).

The SLP has two contracts for energy sales. The MMPA contract provides for electrical sales to the MMPA when the units are available. The contract has various options for RPU to reduce the amount of capacity offered to MMPA. These options to adjust capacity allocated to MMPA under the contract are available in 2005 and 2010. The above balance of loads and resources reflect the current thinking of RPU on the amount of capacity which will be available to RPU from the contract.

Steam sales to the Franklin Heating Station were scheduled to begin in 2004. The steam sales are not anticipated to limit the electrical output of the SLP steam generators until after the 2010 time frame. These reductions in electric capacity have been accounted for in the balance of loads and resources.

Figure S-1
RPU Balance of Loads and Resources
2004-2030



RPU recently completed a study on the environmental aspects of the SLP with regard to existing and potential environmental regulations. It is expected that the RPU will need to make investments in additional emission controls or implement other emission reduction strategies within the next 5 years. Various options are currently under consideration by RPU. Estimated impacts to the SLP have been considered in this study using the results of the environmental report "Analysis of Existing and Potential Regulatory Requirements and Emission Control Options for the Silver lake Plant". In addition to issues at the SLP, RPU considers the long term availability of the Cascade Creek Unit 1 to be in question due to parts availability.

Transmission

RPU is undertaking studies with regional utilities to assess options for reducing the constraints into the southeast Minnesota region and Rochester. Several transmission projects are being considered which will affect the 161kV and 345kV systems in the region.

The development of a project to increase the transfer capacity into the RPU service territory is important to allow RPU to rely on the firm delivery of its CROD amount. Current transmission limitations do not allow the full CROD capacity to be delivered on a firm basis. It is also desirable through the development of a project to have increased transfer capacity for importation of market power or participation in regional projects, such as for a coal or wind resource, on a firm basis.

Use of local generation is becoming more of an issue as area loads increase and the capability of the transmission system becomes more limited. Due to must run issues during portions of the year and contract requirements of MMPA, the SLP is required to remain operational for the foreseeable future. The current limitations on the transmission system being below the level required to support the RPU load from outside resources point out the importance of generation internal to the RPU service area.

Resource Options

The capacity requirements for RPU were reviewed with various futures for the SLP. The futures for the SLP included retirement of the entire plant, maintaining only Unit 4 and maintaining all existing units. The analysis assumed retirement of the existing Cascade Creek Unit 1 in 2015. The capacity needs are summarized in Table S-1.

Table S-1
Range of Capacity Requirements for Various SLP Retirement Scenarios
(MW of Capacity Deficiency)

	2016	2020	2025	2030
All Units in Service	8	56	123	201
Retire CC Unit 1	36	84	151	229
Retire CC1, SLP 1-3	83	131	198	276
Retire CC1, SLP 1-4	128	176	243	321

Expansion alternatives were developed to review various scenarios to eliminate the deficits. These scenarios included various combinations of participation in a regional coal-fired power plant and RPU constructed resources such as combined cycle and simple cycle generation. The scenarios considered for RPU are included in Table S-2.

Table S-2
Resource Portfolios

	Existing Capacity - MW			Capacity Added – MW (year installed)				
Case	CROD	Other	SLP	Coal	Combined Cycle	Twin Pac		
None216-100Coal	216	51	0	100(15)		50(15)	50(20)	50(25)
None216-50Coal	216	51	0	50(15)		100(15)	50(20)	50(25)
None216-100CC	216	51	0		100(15)	50(15)	50(20)	50(25)
None216-LMS100	216	51	0		100(15)	50(15)	50(20)	50(25)
None216-SC	216	51	0			150(15)	50(20)	50(25)
45216-50Coal_CoalFirst	216	51	45	50(15)		50(15)	50(20)	50(25)
45216-50Coal_SLPfirst	216	51	45	50(15)		50(15)	50(20)	50(25)
45216-100CC	216	51	45		100(15)		50(20)	50(25)
45216-LMS100	216	51	45		100(15)		50(20)	50(25)
45216-SC	216	51	45			100(15)	50(20)	50(25)
45216-LMS100-50Coal	216	51	45	50(20	100(15)			50(25)
All216-50Coal_CoalFirst	216	51	92	50(15)			50(20)	50(25)
All216-50Coal_SLPfirst	216	51	92	50(15)			50(20)	50(25)
All216-100CC	216	51	92		100(20)	50(20)		
All216-LMS100	216	51	92		100(20)	50(20)		
All216-SC	216	51	92			50(15)	50(20)	50(25)

The case titles are developed such that the None, 45 or All refers to the amount of SLP capacity available, 216 refers to the CROD amount and the last numbers refer to the MW of resource added. SC refers to simple cycle, CC refers to combine cycle, and LMS 100 refers to a new simple cycle unit being developed. References to CoalFirst and SLPFirst are associated with the order of dispatch.

The simple cycle units considered in this study are based on the current Cascade Creek Unit 2 type facility, the Pratt and Whitney Twin Pac. The combined cycle unit is based on a purchase of a 125MW portion of an area combined cycle project. The coal resources are assumed to be from a regional project whereby RPU would purchase the indicated amount as an owner.

Production cost analysis was performed to determine the amount of energy that each resource would provide over the period 2016 to 2030. Table S-3 provides a summary of the gas and coal energy assumed in the analysis.

Table S-3
Summary of Energy Sources from Gas or Coal Portfolios

Energy in GWh	**2016**		**2020**		**2025**		**2030**	
	Gas	Coal	Gas	Coal	Gas	Coal	Gas	Coal
None216-100Coal	3	1,839	21	2,023	72	2,257	171	2,490
None216-50Coal	36	1,806	79	1,965	187	2,142	423	2,238
None216-Gas	121	1,721	248	1,796	479	1,850	773	1,888
45216-Coal	4	1,838	25	2,019	79	2,250	187	2,474
45216-Gas	34	1,808	93	1,951	243	2,086	536	2,125
All216-Coal	4	1,838	25	2,019	79	2,250	187	2,474
All216-Gas	34	1,808	93	1,951	243	2,086	536	2,125

Note: Above numbers do not include a negligible amount of hydro energy

The above table reflects the energy estimated to be taken from the various generation resources within the respective expansion portfolios. The energy in the gas columns includes energy generated by RPU and purchased from the market. The coal energy includes that purchased from SMMPA and generated by RPU. As seen, where the coal energy is limited to the existing resources, significant increases in the gas energy is necessary. It should be noted that all of the cases include additional gas-fired resources.

Results

The results of the production cost modeling for the traditional portfolios are summarized in Table S-4. The net present values for the cases were developed for the 15 year study horizon in 2015 dollars. The values shown reflect the incremental costs of each option and, therefore, do not include those RPU costs which would be common among all of the cases.

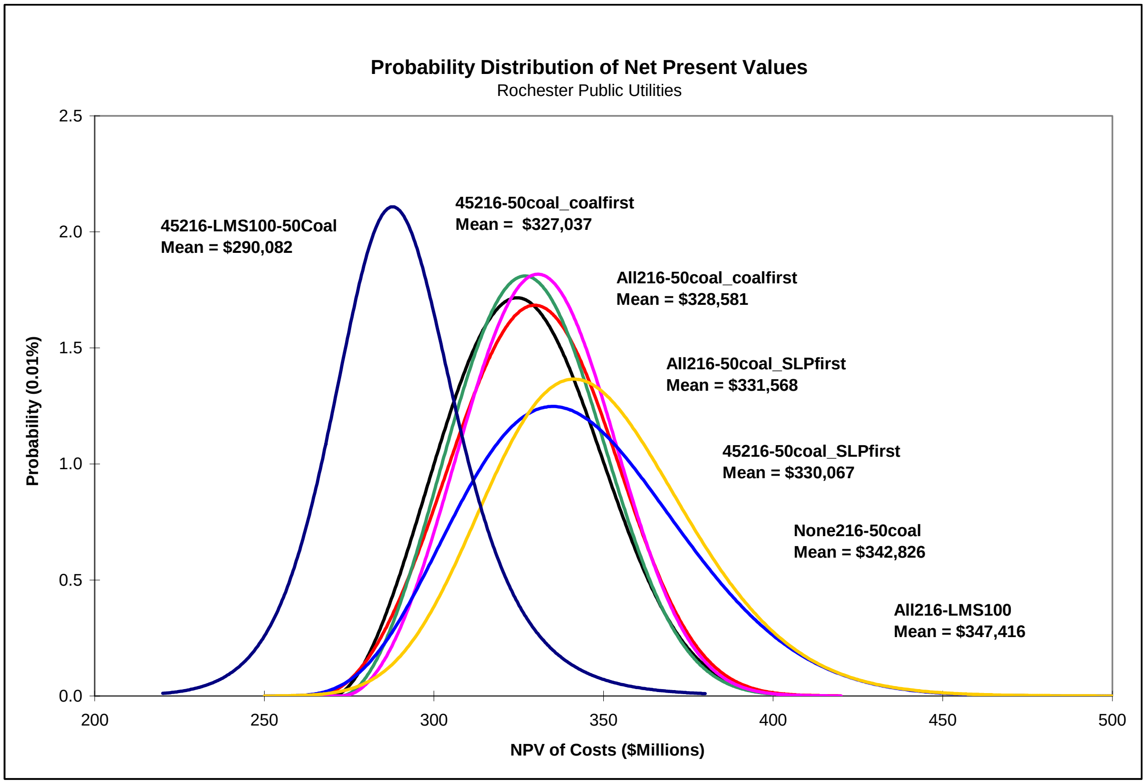
Table S-4
Summary of Net Present Values for Portfolio Options
(2015 $000)

Case	NPV	% Above Base
45216-LMS100-50Coal	$288,674	-
45216-LMS100	$320,892	11.2%
45216-50Coal_CoalFirst	$325,782	12.9%
All216-50Coal_CoalFirst	$327,201	13.3%
45216-50Coal_SLPfirst	$328,750	13.9%
All216-50Coal_SLPfirst	$330,169	14.4%
None216-50Coal	$342,102	18.5%
All216-LMS100	$347,789	20.5%
45216-SC	$347,544	20.4%
All216-SC	$351,098	21.6%
None216-100Coal	$353,725	22.5%
None216-LMS100	$362,430	25.5%
None216-SC	$387,146	34.1%
All216-100CC	$389,434	34.9%
45216-100CC	$396,788	37.5%
None216-100CC	$435,755	51.0%

The above portfolios all have a mixture of coal and natural gas resources used to minimize RPU's overall average energy costs. The results indicate that the availability of low cost energy from the SLP Unit 4 or an additional coal plant purchase is a lower cost scenario than relying only on natural gas for the energy needs above the CROD level.

Risk analysis of the lower evaluated cases was performed. The analysis varied certain assumptions, such as fuel forecast, capital costs, interest rates and other factors. The results are summarized in Figure S-2. The curves show the distribution of probable net present values with the changes in assumptions for the various cases. A higher probability of a net present value indicates reduced risk in that scenario.

Figure S-2
Probable Net Present Values
Lower Evaluated Cases



The risk analysis shown above indicates that combining the benefits of the LMS100 case with the 50MW coal case provides a lower risk case than the all gas cases. The major advantage is the delay of acquisition of the coal unit until its energy can be more fully utilized. This allows RPU to capture the early benefits of the LMS100 portfolio and the later benefits of the 50MW coal portfolios. Therefore, the sequencing of the unit additions should be considered with the gas unit in 2016 and the coal purchase in 2020.

Demand Side Management and Renewable Options

RPU is active in promoting demand side programs to its customers to help conserve electric energy, and reduce demand in its service territory. Numerous programs are offered to assist customers in reducing their electrical requirements. The development of the financial plan for RPU requires the assessment of the impacts that customers are making, and could make, in the reduction of future electrical requirements; therefore, delaying the need for additional capacity.

Current DSM Efforts

Utilities in Minnesota are required to invest a portion of the revenues into DSM programs. For RPU, this amounts to approximately $1,300,000 per year. RPU has created a department to manage the budget associated with DSM programs. The department is staffed with individuals who work with customers to promote the various DSM programs in place, provide energy audit services, and look for new programs to implement.

RPU is working with the cities of Owatonna and Austin, Minnesota on DSM offerings. These utilities have formed the Triad, which allows the cities to share personnel, study costs, and other assets in order to reduce the overheads and program costs associated with the DSM programs.

The programs offered by RPU include:

- Conserve and $ave – a program to promote the use of Energy Star appliances and other high-efficiency equipment in place of lower efficiency options. The program is open to residential, commercial, and industrial customers. Rebates are provided for a variety of appliances, equipment, and lighting options.
- Partners Load Management – a program to allow RPU to control central air conditioner compressors and electric water heaters during times of high demand and reduce the load on the system.
- Energy Audits – these are provided to customers upon request.

The cumulative estimated reductions due to these programs as of January 1, 2004 are:

- Energy savings of 7,860 MWh.
- Demand savings of 5,960 kW.

Using an average of $600/kW of installed capacity and $55 per MWh as an avoided energy cost, the programs have provided approximately $3,500,000 of reduced investment cost and $432,000 of annual energy savings.

Study Approach

A variety of tasks were undertaken to develop the expected impacts that current and potential DSM programs could provide in reducing the RPU need for additional power supply resources. These tasks included an end use survey of RPU's customers, a benefit cost analysis of RPU programs, and an estimation of the electric energy and demand reduction potential for RPU's customer base.

In addition to these tasks, public involvement was solicited to discuss options and considerations from the ratepayer's perspective. RPU developed a task force made up of a representative from the various rate classes and other involved citizens served by RPU.

The results of these efforts are more fully described in Part V. Table S-5 provides a summary of the estimated energy impacts due to expanded DSM programs that were considered likely for RPU. Discussions with the RPU DSM staff and management resulted in revisions to the forecast used to develop the traditional resource plan.

Table S-5
Estimated Additional DSM and Efficiency Impacts
To RPU Energy Forecast

Program	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential											
Central AC	0	236	475	709	709	709	709	709	709	709	709
Blower Motors	0	692	1,391	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076
CFLs	0	63	127	190	190	190	190	190	190	190	190
Refrigerators	0	42	84	125	125	125	125	125	125	125	125
Gas switched appliances	0	83	168	250	250	250	250	250	250	250	250
Commercial											
Central Air more than 7 years old	0	123	248	370	370	370	370	370	370	370	370
No Compact FL	0	185	373	556	556	556	556	556	556	556	556
Non electronic ballast flourescent	0	517	1,040	1,552	1,552	1,552	1,552	1,552	1,552	1,552	1,552
VSD on 3 HP AC unit fans	0	658	1,322	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973
Computers	0	122	245	365	365	365	365	365	365	365	365
Printers	0	43	86	128	128	128	128	128	128	128	128
Copiers	0	55	111	165	165	165	165	165	165	165	165
Gas switched appliances	0	250	503	750	750	750	750	750	750	750	750
Total	0	3,069	6,170	9,208	9,208	9,208	9,208	9,208	9,208	9,208	9,208
Cumulative Total	0	3,069	9,239	18,447	27,656	36,864	46,073	55,281	64,489	73,698	82,906

The estimated demand and energy impacts, including the Mayo cogeneration project, are shown in Table S-6. The Original Energy Forecast was the energy projection used for developing the resource plan described above. The Existing DSM Impacts include the existing RPU DSM program estimated savings. The Future DSM impacts are one half of the saving shown in Table S-5. The Revised Energy Forecast is determined by subtracting the Future and Existing DSM Impacts from the Original Energy Forecast. The Aggressive Energy Forecast includes the remainder of the savings estimated in Table S-5.

Table S-6
Estimated DSM and Efficiency Improvement Impacts
Demand (MW) and Energy (MWh)

Year	Annual Peak	Demand Adjustments	Adjusted annual Peak	Original Energy Forecast	Future DSM Impacts	Existing DSM Impacts	Revised Energy Forecast	Aggressive Energy Forecast
2005	277	16.6	260	1,377,767	0	8,590	1,369,177	1,369,177
2006	284	21.8	262	1,414,967	1,535	56,310	1,357,122	1,355,588
2007	292	23.1	269	1,453,171	4,620	64,550	1,384,001	1,379,382
2008	300	25.1	275	1,495,732	9,224	72,650	1,413,858	1,404,635
2009	308	25.3	283	1,532,702	13,828	80,650	1,438,224	1,424,396
2010	316	26.9	289	1,574,085	18,432	88,500	1,467,153	1,448,721
2011	325	29.2	296	1,616,585	23,036	96,210	1,497,339	1,474,302
2012	334	31.8	302	1,663,932	27,641	103,790	1,532,501	1,504,861
2013	343	34.9	308	1,705,059	32,245	111,150	1,561,664	1,529,420
2014	352	38.4	314	1,751,096	36,849	118,450	1,595,797	1,558,948
2015	362	42.8	319	1,798,375	41,453	125,770	1,631,152	1,589,699

Renewable Energy Options

The state of Minnesota has implemented requirements for renewable energy under Minnesota Statute 2003 Chapter 216B. Retail electric utilities must offer customers an opportunity to purchase, at cost, renewable energy beginning July 1, 2002. RPU is offering customers the opportunity to purchase this energy under its Wind Power program in association with SMMPA.

Utilities are required to generate or procure renewable energy sufficient to ensure that by 2005, 1 percent of total retail sales are from renewable energy. This “Renewable Energy Objective” (REO) ramps up by 1 percent each year until 2015 when a total of 10 percent of retail sales must be from renewable energy. The REO also requires that, of the renewable generation required, in 2005 at least 0.5 percent be from biomass energy technology, increasing to 1.0 percent by 2010. For RPU, the retail sales energy above the CROD from SMMPA would be subject to RPU compliance with the REO.

The integration of this energy into RPU’s resource mix will require adjustments to the dispatch determined in the traditional resource portfolios identified above.

There are several renewable energy options in commercial use. The most often considered include solar, wind, and biomass. In addition, the REO allows the use of electricity generated using municipal solid waste and existing hydro-electric generation to count towards the renewable requirement. The application of these options requires an assessment of their energy production capabilities, resultant power costs and the benefit to the RPU requirements. A more detailed discussion of renewable options can be found in Part V.

The Olmstead Waste to Energy Facility (OWEF) qualifies as biomass renewable energy under the Statute. Since utilities are to provide 1 percent of their energy from biomass, it could satisfy the RPU biomass renewable requirements through the study period. When combined with the Zumbro River hydro facility total renewable requirements could be satisfied until approximately 2027. Table S-7 provides an assumed purchase scenario. Due to the requirement in the REO of obtaining energy from biomass, the output of the OWEF will be required beginning in 2005.

Table S-7
RPU Estimated Annual Renewable Energy Requirements (MWh)

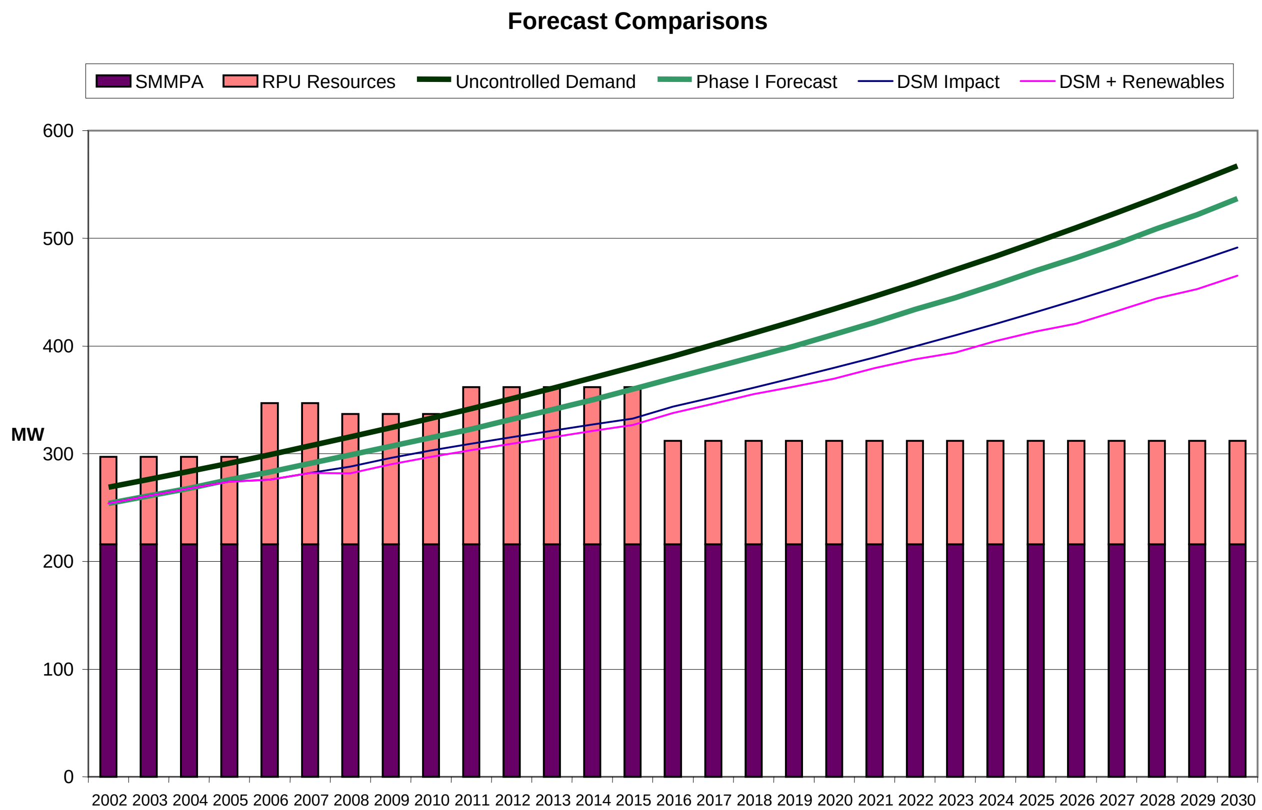
Year	Renewable Requirement (10%)	From Biomass	Available from OWEF 1.9MW @ 75%CF	Available from OWEF 5MW @ 75%CF	From Zumbro River	Total Hydro & Biomass
2016	7,059	71	12,483		9,000	21,483
2017	8,230	82	12,483		9,000	21,483
2018	9,628	96	12,483		9,000	21,483
2019	11,243	112	12,483		9,000	21,483
2020	13,411	134	12,483		9,000	21,483
2021	15,942	159	12,483		9,000	21,483
2022	19,008	190	12,483		9,000	21,483
2023	22,485	225		32,850	9,000	41,850
2024	26,446	264		32,850	9,000	41,850
2025	30,570	306		32,850	9,000	41,850
2026	34,949	349		32,850	9,000	41,850
2027	39,614	396		32,850	9,000	41,850
2028	44,543	445		32,850	9,000	41,850
2029	49,634	496		32,850	9,000	41,850
2030	54,980	550		32,850	9,000	41,850

Note: All energy values in MWh

DSM and Renewable Impacts on RPU Supply Needs

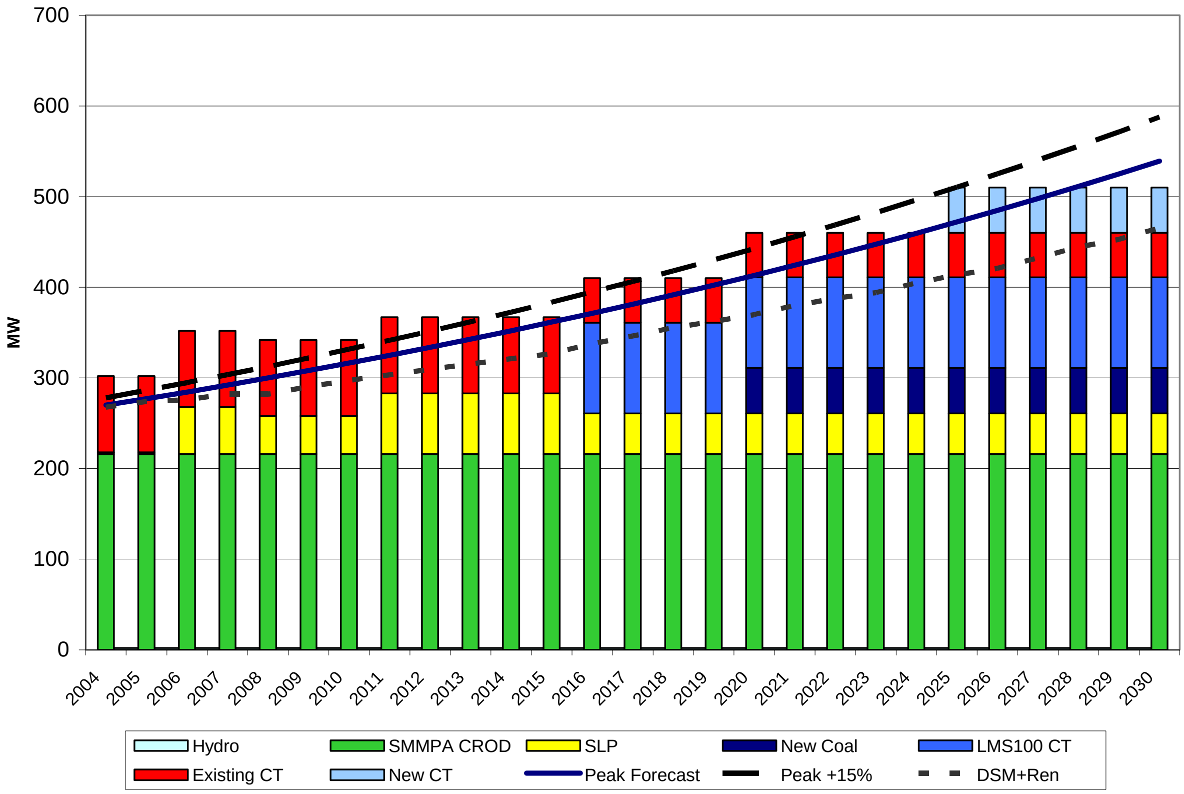
The balance of loads and resources using the DSM and renewable impacts was modified to include the above forecasts. The resulting impacts are shown in Figure S-3.

Figure S-3
Comparison of Base and Revised Forecasts
With DSM and Renewable Impacts



The impacts to the forecast indicate that the projected impacts of DSM and renewables do not delay the year when RPU becomes capacity deficit, however, they substantially reduce the amount of capacity needed. In addition, they delay the need for additional capacity in the future. Figure S-4 is the balance of loads and resources of the recommended traditional resource plan. As shown, the impact of the DSM and renewables on the forecast allows a delay in the installation of the LMS-100 combustion turbine by about 2 - 3 years. The impacts also allow a delay in the need for the coal unit by a similar period.

Figure S-4
Impact of DSM and Renewables
On Lowest Evaluated Traditional Resource Plan
Balance of Loads and Resources



Financial Analysis

The results of the resource planning, demand side management and renewable assessments were reviewed on an incremental cost approach to determine lower evaluated options. In order to bring these options together to determine the recommended RPU future, a financial forecast model was developed by RPU to incorporate the total costs of RPU. This model allowed a complete evaluation of future costs, the impact to average rates and other financial factors of interest to RPU.

The financial model was used to analyze the following futures:

- The recommended traditional resource expansion plan from Part IV with the forecast unaffected by demand side management,
- The recommended plan adjusted by using the normal demand side management forecast with SLP operating on coal and adjustments to the new resources,

- The recommended plan adjusted by using the normal demand side management forecast with SLP operating on natural gas and the coal unit replaced with gas-fired capacity,
- The recommended plan adjusted by using the aggressive demand side management results with SLP operating on coal and adjustments to the new resources,
- The recommended plan adjusted by using the aggressive demand side management results with SLP operating on natural gas and the coal unit replaced with gas-fired capacity.

A complete discussion of assumptions and methodology can be found in Part VI.

A variety of assumptions were made to the financial model. The main driver for the model is the energy and demand forecast. The load forecast was used to derive estimates for a variety of other assumptions, such as:

- Energy dispatch from RPU sources, including market sources, above the SMMPA supplied energy,
- Generation fuel expense,
- Purchased power expense for energy, capacity, and transmission,
- Administrative and general costs,
- Distribution and substation additions,
- Retail revenue forecasts.

Forecasts for investment in other projects, such as for transmission upgrades, capital investments in plant, and other improvements were provided by the respective operating divisions of RPU. The Silver Lake Plant was assumed to have the recommended environmental modifications from the Utility Engineering report “Rochester Public Utilities Emissions Control Feasibility Study, Silver Lake Plant,” Dec 2004 in the futures with coal. The budgets for the demand side management and marketing programs were included based on the level of DSM considered in the forecast.

The list of input assumptions is included in Appendix V.

The financial model uses the energy forecast and estimated energy price from the resources available to determine the amount of energy derived from each source. If the load level is at or below the 216MW level of the SMMPA contract, then the energy is assumed to come from SMMPA. If the load is above the 216MW level, then the lowest cost resource is dispatched to provide the energy with the exception that small load increments were dispatched first from peaking units until the point where the increment was high enough to feasibly dispatch baseload generation.

The economic impacts of resource additions were determined based on the estimated capital, fixed and variable operating and maintenance costs. The targeted financial goals for debt service coverage ratios, average cash balances and other targets based on capital investments were included. In-service years and the amount of capacity added were adjusted in the futures with demand side management included to reflect the benefits to delays in and amounts of capital investment.

Estimates of purchases from the market were made using a forecast market demand and energy price. For certain years, market capacity was purchased on a seasonal basis to provide the necessary capacity shortfall rather than install a new resource. Also, when market energy was estimated to be lower cost than an RPU resource's energy cost, the market was used to provide the energy.

The operation of the SLP to meet wholesale energy and steam production contract obligations was modeled. The operations included estimated energy and steam production based on current discussions with counter parties to the contracts.

The operation and capital budgets of each RPU division were incorporated to provide a complete financial picture of the utility. The revenue requirements were then used to determine the amount of adjustment to rates necessary to meet those requirements. Average impact to retail rates and customer average bills were also estimated. The model covers a thirty year time period from 2005 to 2034.

Externalities

The values of externalities were included in this analysis. The 2003 values of externalities used by the Minnesota Public Utilities Commission (Rural) for utilities to evaluate externalities were adjusted for the gross domestic price inflator (4.4%) for 2004. A midpoint range for the adjusted values was selected for use in the analysis.

The emissions from the resources considered in the financial model were placed on a dollar per MWh basis for use with the expected dispatch MWh determined from the financial model. Externalities on contract and market purchases were also included to reflect one half of the purchases from new coal units and one half from combined cycle gas units.

Renewable energy from the Zumbro River facility was included in the financial model as the primary renewable resource, wind energy under the SMMPA program included at its historical average, and with OWEF assumed to be the biomass resource.

Results

Resource Plan

The reduction in the demand and energy forecast with the DSM impacts provides an opportunity to delay the gas resource considered for 2016 and the in service year and amount of capacity for the coal resource considered in 2020. In the financial model, the combustion turbine considered for installation in 2016 was delayed two years and the coal unit was reduced to 25MW and its in service date delayed to 2025.

Rates

Figures S-5 and S-6 provide the results based on average retail rate impacts and average customer bills. As seen, there are significant advantages in the demand side management impacts on both rates and average bills. When considering the cost impacts due to the futures with and without coal, it is seen that the coal case provides economic benefits.

The rate impacts determined from the analyses indicate that RPU, in any of the futures, is expected to need rate increases of from 1 to 3 percent in almost each year of the assessment. The differences in the expected and aggressive demand side management scenarios were not significant. The more detailed results of the financial model analyses are included in Part VI and Appendix V.

Figure S-5
Retail $/MWH-Major Customer Classes

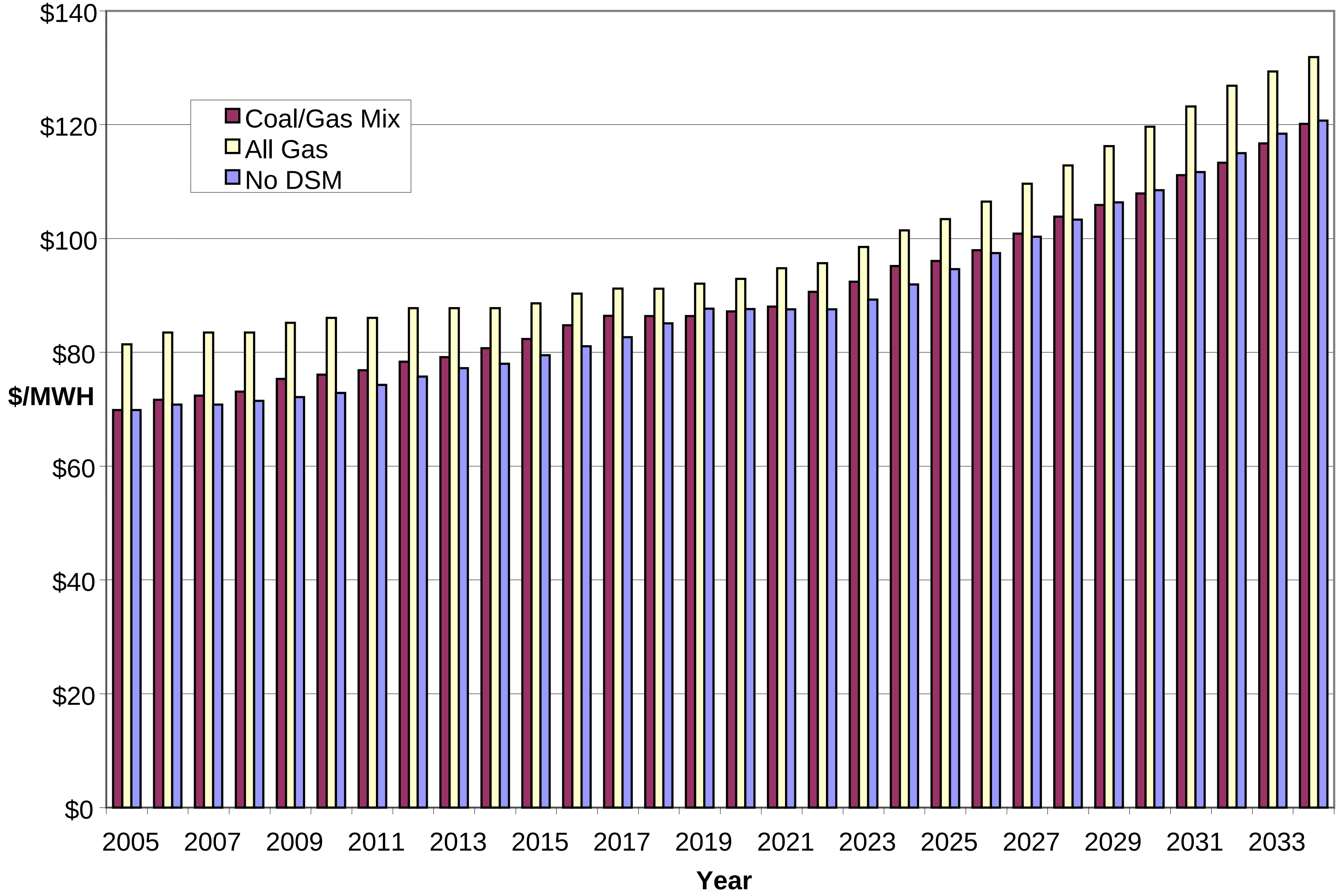
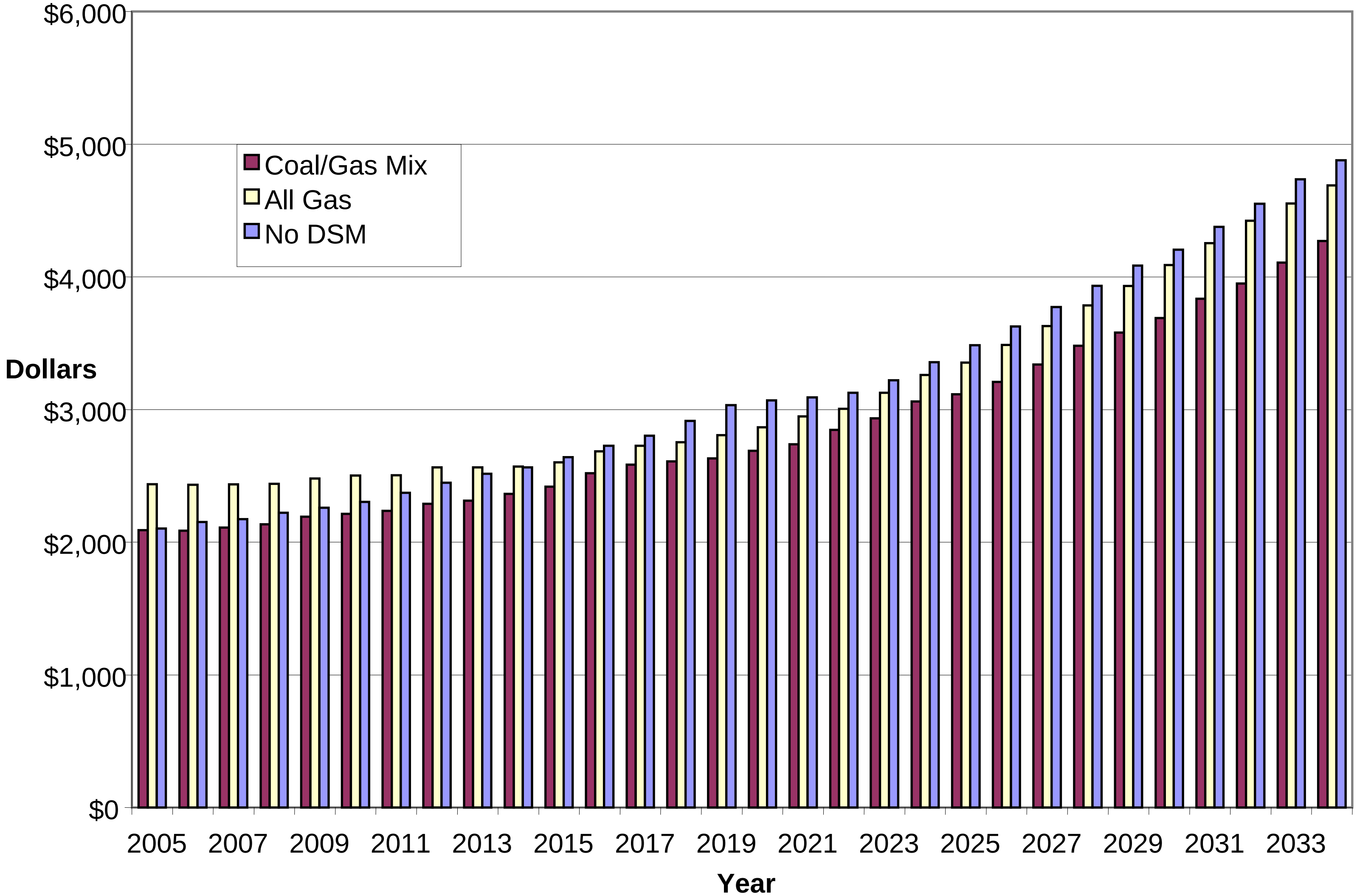


Figure S-6
Average Annual Bill-Major Customer Classes



Emissions

The emissions from each of the futures were considered from both absolute tons per externality and the cost aspect using the Minnesota value for externalities. Table S-8 provides the summary of tons emitted by externality based on the energy dispatch used for the RPU retail resource future over the thirty years of the analysis. As shown, there is a substantial advantage to the demand side reductions. The costs of the externalities and the total costs of the specific future are included in Table S-9.

Table S-8
Total Tons of Emissions by Scenario

Scenario	SO2	Nox	PM10	Pb	CO	CO2
Original Forecast	7,808	4,587	770	1.25	9,811	10,472,370
Normal DSM Coal & Gas	5,228	3,105	485	0.79	7,048	6,263,420
Normal DSM All Gas	379	5,086	296	0.10	8,341	3,784,419
Aggressive DSM Coal & Gas	4,931	2,886	448	0.73	6,504	5,720,385
Aggressive DSM All Gas	343	4,714	272	0.09	7,644	3,474,437

Table S-9
Retail Portion of RPU Costs of Various Plans with Externalities
(2004$ 000's)

Scenario	Retail Revenue	Externalities	Total
Original Forecast	$ 5,649,613	$22,308	$ 5,671,921
Normal DSM Coal & Gas	$ 5,134,851	$13,390	$ 5,148,241
Normal DSM All Gas	$ 5,672,269	$ 8,325	$ 5,680,594
Aggressive DSM Coal & Gas	$ 5,104,864	$12,236	$ 5,117,100
Aggressive DSM All Gas	$ 5,569,761	$ 7,646	$ 5,577,408

Summary

Overall, RPU is in relatively good condition to meet its load requirements for several years without any additions to its resource mix. Challenges to RPU in the area of transmission reliability and understanding what future market operation impacts will bring are typical of the environment in which utilities operate today and will be a primary focus of RPU. The transmission issues confronting RPU may require additional internal generation to maintain reliability within the RPU service territory prior to when units would be needed to serve load growth. Plant related issues will include the investment necessary to bring the SLP into compliance with environmental regulations currently taking affect. Based on the analysis performed for RPU in this effort, Burns & McDonnell offers the following conclusions and recommendations.

Conclusions

Based on the analysis performed for this study, Burns & McDonnell has developed the following conclusions:

1. The uncertainty surrounding the conversion of the electricity wholesale market in the RPU region from its traditional operation to its new operation under MISO and the existing transmission limitations for importing power into the RPU area makes it necessary for RPU to continue to have capacity available within its service area for reliability and economic purposes.
2. The use of traditional resources to meet the RPU capacity obligations is lower cost than the use of wind or solar equivalent capacity. Energy costs from certain renewable options can be attractive when compared to the energy costs from coal, gas, or market resources.
3. The impacts of demand side management allow RPU to delay and reduce the amount of capacity required when compared to the forecast without significant demand side management effects included.
4. The future evaluated with coal and gas energy and aggressive demand side management was the only future that provided both lower average rates and lower average total bills when compared to the other futures. This ranking is not changed with the inclusion of externalities.
5. The emissions from the aggressive demand side management future with coal and gas are approximately one-half of the emissions from the traditional resource future.
6. Considering the load forecast, RPU has several years before it is in a capacity deficit condition due to load needs. Estimates of DSM and renewable impacts to the forecast provide the opportunity for RPU to delay the installation of resources by two to three years, depending on the successful acceptance of the DSM programs by the RPU customers.
7. The development of the MISO Day 2 market will make day ahead pricing more predictable and potentially provide RPU with the opportunity to engage customers in demand adjustments based on the cost of energy. The current Partners program could see a decrease in the number of MW under control due to more efficient air conditioners being installed on the system and potential fuel switching of water heaters. These two developments are an indication that RPU should consider realigning its approach to demand reductions on the customer side of the meter. Because of this need, RPU should prepare a pilot program for implementation of demand response type programs across the residential, commercial and industrial classes in order to gain experience and begin shifting away from the direct control programs to market based programs.
8. RPU’s renewable obligations under the Minnesota Statute Chapter 216B can be met for several years through purchase of energy from the OWEF and the Zumbro River hydro facility. If the OWEF facility is expanded, as is being considered, RPU renewable energy requirements could be satisfied until approximately 2027 with these two resources.

9. Discussions with the OWEF should proceed to determine if additional output is available. If it is not, then wind energy should be pursued as the next renewable option to satisfy energy obligations under the REO. Based on the cost and output of photovoltaic units, solar photovoltaic is the most expensive renewable option for the RPU to pursue.
10. Based on information from RPU, the SMMPA is in discussions on acquisition of additional resources which could affect the cost of capacity and energy under the CROD. At the current time, there is insufficient information to be able to determine how DSM programs could reduce the impact of these potential costs. If SMMPA moves ahead with resource acquisitions based on RPU impacts to the SMMPA resource mix, RPU should discuss with SMMPA the ability of DSM options to reduce the resource need impacts to SMMPA.

Recommendations

Based on the analysis performed for RPU in this effort, Burns & McDonnell is of the opinion that RPU should:

Over the next few months:

1. Minimize its involvement in reviewing participation in regional coal projects. RPU is not in need of additional coal capacity with the current 216MW CROD level and load forecast until approximately 2020. Therefore, participation in any coal plant currently being developed does not appear to be advantageous.
2. Pursue firming up the transmission system to allow firm delivery of the CROD amount of 216MW.
3. Improved transmission import capability should be reviewed with area utilities to allow increased access to market capacity. Although the resource plans presented in this study anticipate future resource additions, there is also continued reliance on market purchases to meet future load growth.
4. Consider taking options on approximately 100 acres of land within the RPU service territory near a high pressure gas line and transmission facilities under RPU control for installation of future combustion turbine capacity.
5. Develop a parallel path project to accelerate installation of combustion turbine capacity required in the long term plan to maintain system reliability should the selected transmission upgrade project be delayed.
6. Develop the upgrade plan and timing for SLP Units 1-4 for the addition of emission controls and other life extension modifications.
7. RPU should monitor the operations of the MISO Day 2 market to determine how to participate in the market over the next few months.

Between 2005 and 2015:

1. RPU should continue to design and market DSM programs to achieve the levels of forecast reductions for demand and energy. Periodic comparison of actual results to those forecasts should be made to determine if adjustments in the forecast results are necessary.
2. RPU should take advantage of renewable energy from the Zumbro River resource to the full extent of its output. The renewable energy from the OWEF should be considered to provide the RPU biomass energy requirements. Purchases above the requirements should be compared to the cost of other energy available.
3. Complete the transmission upgrade or the installation of additional combustion turbines to maintain system reliability.
4. If the transmission upgrade is completed, compare the market conditions at the time to the installation of additional generation resources within the service territory.
5. Review the then current generation technology, fuel options and RPU needs against the long range plan developed herein to determine if new technologies or reduced RPU needs have usurped the analysis and recommendations associated with current options.
6. Complete the modifications to the SLP Unit 4. Initiate the emission controls to be applied to Units 1-3 in light of their expected operation.
7. Around 2014, assuming that new generation is required in accordance with the long range plan and that generation has not been installed in connection with the transmission issue, begin the process for installation of approximately 50 to 100MW of natural gas-fired generation for an in service date of 2018. The generation should be low capital cost with as low an operating cost as is consistent with expected operating capacity factors.

Between 2015 and 2030:

1. Install generation as necessary and prudent using the long range plan prepared above as a guide and comparing the assumptions used herein to the existing market conditions and resultant DSM impacts to the RPU needs. The generation additions should follow the in service schedule identified in portfolio 45216-LMS100-50Coal as modified by DSM results.
2. Around 2015, depending on the status of the RPU system needs, the regional market for base load projects being developed, and other technology considerations for resource options, RPU should consider taking an option on approximately 1500 acres to support the development of a coal-fired generation plant within the RPU service territory. The site should have access to rail, electric transmission and water infrastructure to support several hundred megawatts of generation.

3. If development of a local coal unit appears likely, purchase the necessary land and begin the development process around 2017 for an in service date of 2025.

*****

Part I

Introduction

The management of Rochester Public Utilities (RPU) is interested in developing a long range baseline infrastructure plan for the utility. The growth of the customer load will require acquisition of additional generation resources and upgrades in the utility's local and the region's transmission systems. These projects will be competing for capital from the RPU. In order to minimize the investment in these areas, a long range plan is needed which provides a coordinated approach to resource expansion.

The RPU is confronted with numerous decisions associated with its power supply resources. Several of these decisions will need to be made in the next several months. The outcome of these decisions could have a significant impact on the financial requirements of the RPU over the next several years. In order to develop information about the various futures available to RPU and what the financing requirements might be for the futures, RPU decided to study how various long term decisions could impact the near term financing requirements.

The approach taken by RPU was to develop a multi-phased approach to understanding these needs. The various phases include:

- Environmental modifications necessary at the Silver Lake Plant
- Transmission upgrade studies for regional improvements
- Review of traditional resource expansion alternatives
- Review of demand side management and renewable alternatives

This report provides information on the traditional generation resource planning undertaken to provide a baseline for comparing the DSM and renewable options and understanding how RPU intends to use the transmission system.

Being a municipal utility, RPU is responsible to the citizens of Rochester, who are the customers it serves. In order to understand the issues of importance to its customers, RPU has periodic customer satisfaction surveys performed. According to customer satisfaction research conducted by Morgan Marketing in 2001, keeping the price for electricity as low as possible and aggressively pursuing energy conservation and renewable generation strategies were ranked in order as the highest needs among 18 performance attributes. The research included telephone, mail-in and personal interviewing of residential, commercial and industrial customers.

The development of this plan recognizes those needs. Phase I herein reviewed the needs and traditional approaches to meeting the resource needs of RPU's customers in a low cost manner in accordance with reliability standards in the industry. It established a baseline from which to measure potential impacts of renewable energy sources and customer modifications to consumption. The Phase II effort reviewed conservation, demand side management and renewable options to be integrated into the RPU system which could reduce or eliminate the need for the addition of the traditional resources.

Utility Issues

The utility industry in general and RPU specifically are operating amidst changing local, regional and national issues which affect utility operations. On the local level, many of the issues require decisions by local officials who regulate RPU and will determine the local course of the utility. Regional and national issues are typically beyond the influence of these officials. These issues are closely watched by RPU and others and RPU is a participant in the national debates. However, the decision on what policies to implement on a state, regional or national level is beyond the RPU control.

The issues which RPU is confronting on the local, regional and national levels include:

Generation

Local

- Silver Lake Plant Emissions
- Status of local generation in future system needs
- Must Run issues required of local generation and emission impacts
- System operation changes based on Midwest Independent Transmission System Operator (MISO) development
- Reserves available

Regional and National

- Status of regional generation
- Cost and availability of natural gas as a utility fuel
- Availability and value of regional joint generation projects
- Implementation of MISO Market Operations
- Technology advancements
- New emission/operation regulations

The use of local generation is becoming more of an issue as load increases and the capability of the transmission system becomes more limited. Due to regional reliability issues during portions of the year and contract requirements of RPU, the Silver Lake Plant (SLP) may be required to remain operational. The useful life of the facility and improvements necessary to keep the plant compliant with operating permits is a concern. A study on the emission improvements recommended for the plant is being prepared.

Transmission and Distribution

Local

- Transmission for firm delivery of Southern Minnesota Municipal Power Agency (SMMPA) contract rate of delivery
    - Maximum import of the transmission system
    - Ability to build new transmission facilities outside of Rochester
- Distribution reliability
    - New substation and lines will be continually needed as the load grows
    - Capital requirements
    - Rights of way
- Reserves available

Regional and National

- Status of regional transmission improvements
- Implementation of MISO operations
- Technology advancements
- New Regulations

The transmission import capacity into RPU is constrained during certain hours of the year. Capacity has degraded to the point that the firm delivery of the SMMPA Contract Rate of Delivery (CROD) is being affected.

Load Growth

- Annexation, expansion of RPU service territory impacts capital needs
- Growth rates affect RPU investments
    - Local economy
    - Mayo Clinic
- Risks of economic development expansion (ie Genomics)
    - Overbuild
    - Underbuild
- Matching the investment to meet changes in load

The RPU load growth is closely linked to the growth of the Mayo Clinic and other major employers in the area. Average system growth is projected by the RPU forecasting group to be approximately 2.7% per year between 2004 and 2030.

Financial and Administrative

Local

- Impact of requirements on the rates
- Impact of Homeland Security regulations and capital needed to meet the needs
- Training and attraction of qualified staff
- RPU productivity due to the time it takes to report and comply with the new regulations
- Knowledge and communication of the capital dollars needed to:
    - Internal stakeholders
    - External stakeholders

Regional and National
- Cost of Borrowing
- Availability of staff versus the need

Long Range Plan

The development of the long range baseline infrastructure plan (Plan) will incorporate aspects of an integrated resource plan and a financial plan for the utility. Issues which the Plan will cover include, but are not limited to:

- Basic generation and transmission resource expansion including addition of internal resources and participation in regional projects.
- Consideration of the renewable portfolio requirements of Minnesota
- Demand side management, customer involvement in managing loads
- Estimated costs for the utility and financial model development

The RPU is not required to file the Plan with a regulatory agency at the state or federal level. However, the Plan is organized and includes the basic requirements of these types of studies performed by state regulated entities.

The analysis required to support these decisions is the subject of this report. RPU retained Burns & McDonnell to assist the RPU in the development of the Plan. The first effort was to analyze the power supply needs to the 2030 time frame in order to identify any longer term issues which could impact shorter term decisions. The major power supply resource issues which confront RPU include:

- The benefit of the Silver Lake power plant as a long term resource
- The investment in the Silver Lake power plant for emission controls
- The upgrade of the transmission capability into Rochester to allow firm use of the purchased capacity and energy
- The development of renewable resources to meet Minnesota requirements
- The participation in regional coal plants

The review of these issues was divided into two major time periods. The periods were from 2005 to 2015 and from 2016 to 2030. These time frames were developed to coincide with the termination of the Minnesota Municipal Power Agency (MMPA) contract, at which time the RPU will regain the complete output of the SLP for its own use.

The first period reviewed was from 2016 to 2030. This period allowed a review of the load growth of RPU compared to the available resources. Various generation expansion plans were evaluated which included futures with differing amounts of the SLP available.

The second period reviewed was from 2005 to 2015. This period was reviewed after the later period to determine what shorter term actions needed to be taken in order to efficiently invest capital to support RPU’s longer term power supply plan.

Methodology

The initial effort in the review was for RPU to determine what the major decisions and future options available to meet its power supply requirements might be. The use of a decision tree process resulted in identification of the decisions, assumptions and sequencing of the issues. The development of the analysis required review of the following issues:

- RPU's projected demand and energy requirements
- Status of RPU resources
- Sources of energy
- Transmission capabilities
- Renewable resource requirements in Minnesota
- Regional coal-fired generation projects

The review of the power supply alternatives for RPU was performed using a load forecast prepared by RPU over the study horizon. The forecast was applied to the hourly load profile of RPU which resulted in an hourly forecast for the entire study period.

A review of the load growth of RPU and the energy needs of the utility indicated that the energy available from the SMMPA would approach its maximum utilization in the 2010 to 2015 time frame. Resource planning is needed to determine the future requirements of the utility considering various scenarios for the MMPA contract, the contract for steam sales to the Mayo clinic, improvement of the transmission system and the future of the SLP.

Burns & McDonnell reviewed the projected demand and energy needs of RPU. These needs were compared to the existing sources, which allowed the resource needs of RPU to be identified. The development of these items allowed expansion plans to be created. These plans were reviewed using an hourly costing model which allowed each expansion alternative to be evaluated for fixed and variable costs. Assumptions for the analysis were developed by Burns & McDonnell with input by RPU.

In order to assist in developing the various futures for power supply which RPU could pursue, decision tree analysis was used to organize the options. Meetings were held with RPU to construct the decision tree used to organize the analysis. Risk assessment was performed on the various futures to identify the variability of the outcome with changes in the assumptions. A summary decision tree from the more extensive one developed with RPU is shown in Figure I-1 at the end of this section. This decision tree is for the period 2016 to 2030.

Burns & McDonnell used an hourly and monthly spreadsheet production cost model to review the costs of the various futures considered. The use of this model allowed application of ranges of probable values for certain assumptions to determine the risk of various futures. Estimates and projections prepared by Burns & McDonnell relating to interest rates and other financial analysis parameters, construction costs and schedules, operation and maintenance costs, equipment characteristics and performance, and operating results are based on our experience, qualifications and judgment as a professional consultant. Since Burns & McDonnell has no control over the numerous factors affecting the basis for the estimates and projections, Burns & McDonnell does not guarantee that the actual future costs will not vary from those used by Burns & McDonnell in the preparation of this study.

Study Development

The power supply study is the initial effort for the overall development of the RPU Plan. RPU desired the review of supply side expansion plans first to allow study of effective, economical demand side management, other customer related options and renewable energy resources to reduce or eliminate the need for development of additional traditional supply side resources.

Report Organization

Part II provides the review of the existing RPU resources and of the supply side resources considered to meet RPU's future demand and energy needs. Part III discusses the portfolio analysis of the various approaches and provides conclusions and recommendations on the attractive alternatives and other issues associated with the supply side needs. Part IV provides the projected resource requirements of RPU over the study period which allows the estimated timing and needs for additional funds. The demand side and renewable analyses are included in Part V of this study. Part VI includes detailed financial forecasts for a variety of futures.

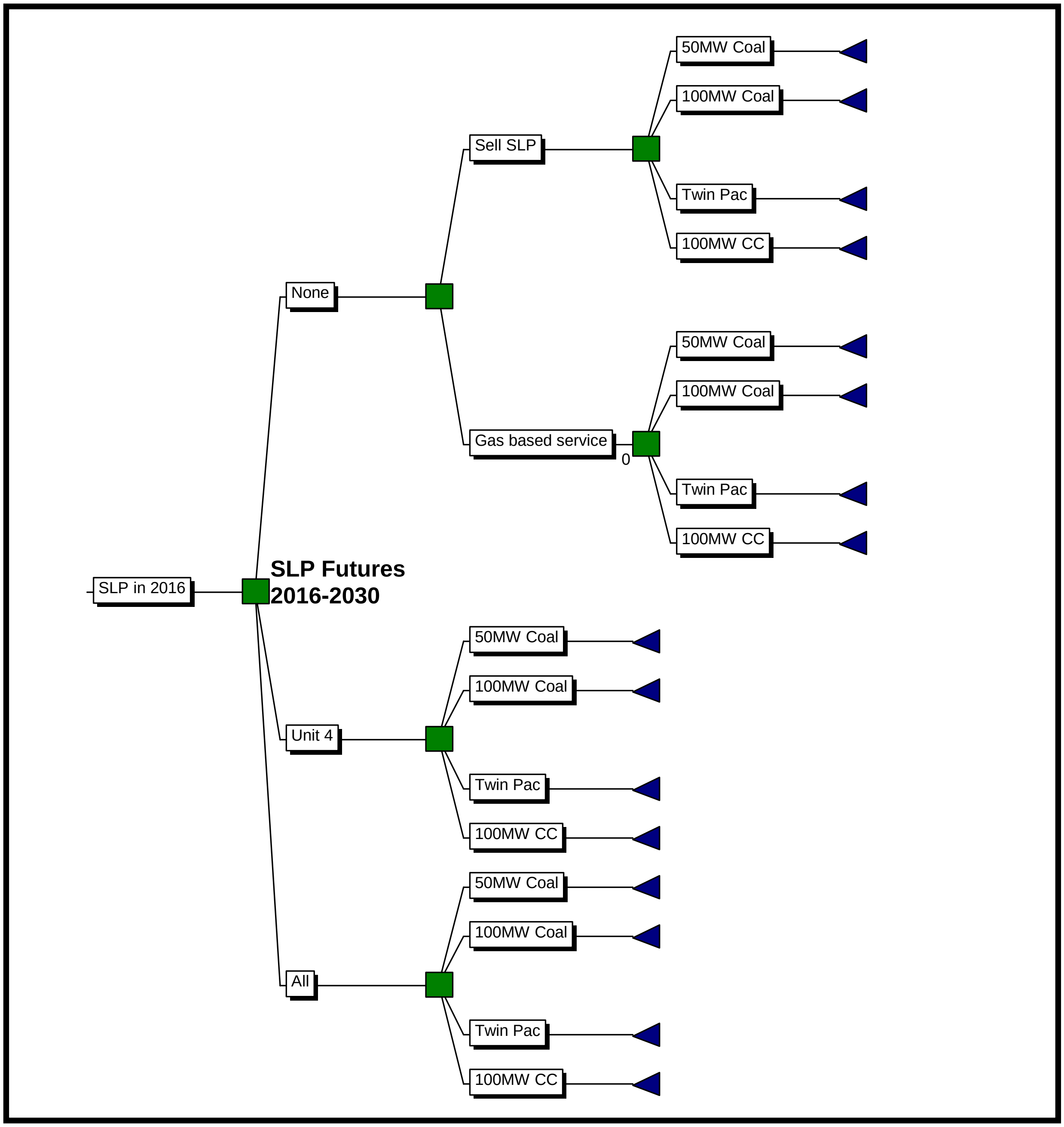


Figure I-1
Summary Decision Tree
Traditional Power Supply Options

*****

Part II

Power Supply Resources

Rochester Public Utilities (RPU) is responsible to meet the electrical energy needs of the citizens of Rochester, Minnesota and certain areas surrounding Rochester. The loads include general residential and commercial loads as is typical of large metro areas. Larger customers served by RPU include the various hospitals within Rochester, such as the Mayo Clinic, and a large IBM facility. RPU owns and operates generation resources to meet its demand and energy needs. RPU is also a member of the Southern Minnesota Municipal Power Agency (SMMPA) which provides RPU with a major portion of its energy requirements.

This part of the report discusses:

- RPU's projection of its demand and energy needs
- The existing RPU supply side resources
- Options for meeting demand and energy needs

Load Forecast

RPU continually reviews its demand and energy requirements. The development of the forecast considers the historical load growth, effects of economic development, weather, the impacts of ongoing demand side management programs and various other factors. RPU develops the forecast and applies it to a typical yearly hourly load profile. This provides an hourly load forecast for the study horizon to 2030. The forecast provided by RPU is summarized on an annual basis on Table II-1. The monthly and hourly load forecasts are included in Appendix I.

The RPU load growth is closely linked to the growth of the Mayo Clinic and other major employers in the area. Average system growth is projected by the RPU forecasting group to be approximately 2.7% per year between 2004 and 2030. This compares to an average compound growth of 3.5% over the past 15 years.

There are considerations of large employment opportunities in the RPU area, such as the Genomics facility. Also, Rochester is discussing annexation of various areas around the current city limits. These issues could have substantial impacts to the system resource requirements.

Table II-1
RPU Forecast of Demand and Energy
2003-2030

Year	Annual Peak Demand (MW)	Total Annual Energy Requirements (MWh)
2003	261	1,306,276
2004	268	1,344,534
2005	276	1,377,767
2006	283	1,414,967
2007	291	1,453,171
2008	299	1,495,732
2009	307	1,532,702
2010	315	1,574,085
2011	323	1,616,585
2012	332	1,663,932
2013	341	1,705,059
2014	350	1,751,096
2015	360	1,798,375
2016	370	1,851,046
2017	379	1,896,798
2018	390	1,948,012
2019	400	2,000,608
2020	411	2,059,202
2021	422	2,110,100
2022	434	2,167,072
2023	445	2,225,583
2024	457	2,290,766
2025	470	2,347,559
2026	482	2,410,943
2027	495	2,476,038
2028	509	2,548,370
2029	522	2,611,549
2030	537	2,682,061

Resource Review

RPU has a number of resources to meet its demand and energy requirements. These include a diverse mix of coal, gas and hydro-electric generating units. The RPU also has a significant amount of energy provided under its contract with the SMMPA. The units owned and operated by RPU are located at the following sites:

- Silver Lake Power Plant
- Cascade Creek Substation
- Zumbro Hydro Plant

To efficiently manage its resources, RPU has entered into contracts for electric sales to the Minnesota Municipal Power Agency and for steam sales to the Franklin Heating Station (Mayo Clinic). These contracts are furnished from the Silver Lake resources. Based on a forecast of expected resource allocations for these sales, the resources that RPU will have available to meet its obligations are summarized in Table II-2 and shown graphically in Figure II-1.

Figure II-1
RPU Forecasted Load and Resources

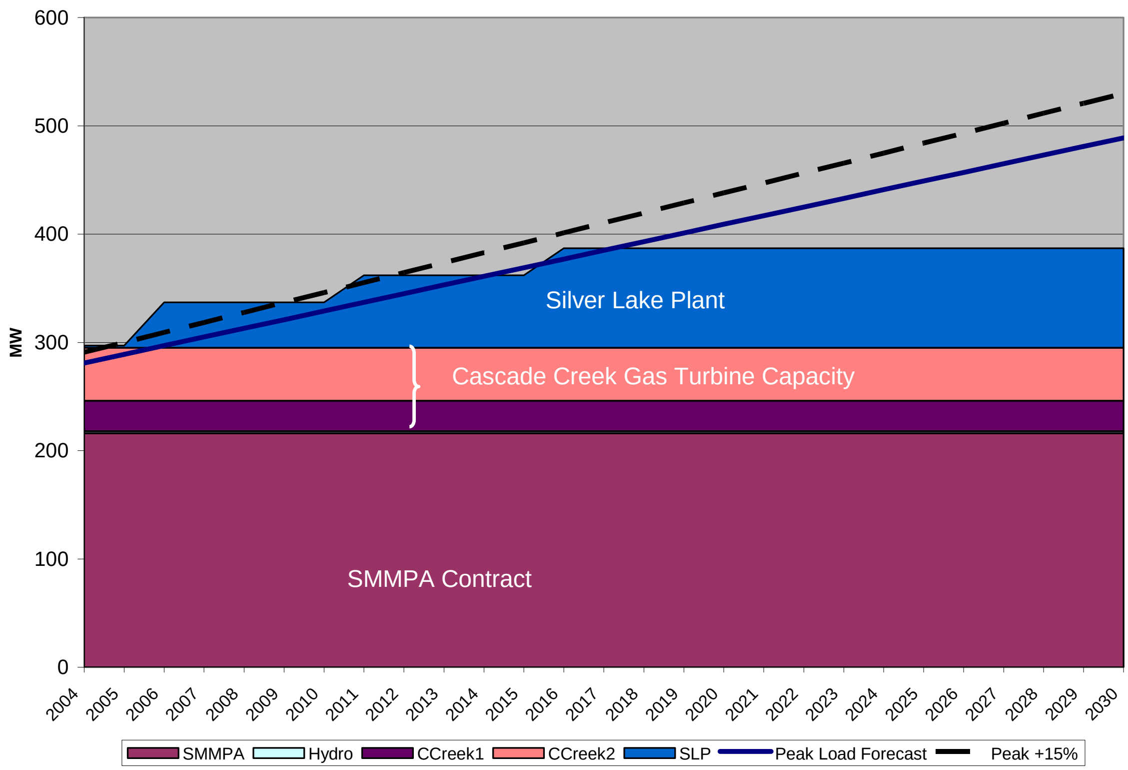


Table II-2

RPU GENERATION CAPABILITY FORECAST 2004 - 2030

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Load Forecast	270	277	284	292	300	308	316	325	334	343	352	362	371	381	392	402	413	424	436	447	460	472	485	498	511	525	539
Peak Load w15% Reserves	278	286	295	304	313	322	332	341	351	362	372	383	395	406	418	430	443	455	469	482	496	510	525	540	555	571	588
Generation Capability SMMPA w15% Reserves	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216
SLP Capacity Available w/ Mayo project	2	2	52	52	42	42	42	67	67	67	67	67	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92
Hydro	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Gas Turbine 1	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
Gas Turbine 2	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Available RPU Capability	81	81	131	131	121	121	121	146	146	146	146	146	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171
Total Generation Capability	297	297	347	347	337	337	337	362	362	362	362	362	387	387	387	387	387	387	387	387	387	387	387	387	387	387	387
Excess Capability	19	11	52	43	24	15	5	21	11	0	-10	-21	-8	-19	-31	-43	-56	-68	-82	-95	-109	-123	-138	-153	-168	-184	-201

As shown in the above table and graph, RPU becomes resource deficit in 2013. The following paragraphs provide a description of the above resources and issues associated with continued production from the generating units over the study period. Detailed assumptions about the units and their operating parameters can be found in Appendix II.

Silver Lake Plant

The Silver Lake Power Plant was conceived by the RPU during World War II. The first unit rated 7500kW was in full service in December, 1949. The annual growth of Rochester electrical load in the late 1940s was approximately 15 percent. This growth prompted planning for a second unit that was brought on line in 1953. This unit was sized to 11,500kW.

Continual planning due to load growth and attraction of customers such as IBM indicated that a third unit at the plant was needed. The unit was sized at 22,000kW. Construction began in mid-1961 and the unit went into commercial operation in November, 1962. This unit was cooled with a cooling tower and also with cooling water from Silver Lake. The resulting warm water allowed portions of Silver Lake to be ice free in the winter, leading to the attraction of the Canadian Geese to winter on the lake.

Average energy consumption per customer essentially doubled between the mid-1950s and late 1960s. In addition, the population of Rochester continued to expand. The fourth unit added at SLP was part of a larger overall power supply expansion plan. This unit was rated at 58,000kW. This unit was constructed with an electrostatic precipitator to remove particles from the unit's emissions. The construction of the unit was completed in 1969.

Fuel for the plant was provided by natural gas and coal. The utility conformed to Pollution Control Agency guidelines and installed precipitators on each of the three remaining units in the 1970s. The plant has been operating steadily since its units went commercial. Reduced utilization of the plant occurred in 1988 due to RPU's participation in SMMPA. The Sherburne County Unit 3 went commercial in 1988 and all of the requirements of the RPU could be met with SMMPA resources. When SMMPA provided all of the energy requirements of the RPU, the excess capacity and energy of the SLP was contracted to the Minnesota Municipal Power Agency. Current usage of the plant to meet steam and electricity contract sales maintains its viability and usefulness. The RPU capped its purchases from the SMMPA in 2000 and is providing the capacity and energy above a base amount of 216MW.

Plant Basics

The SLP consists of four boilers which produce steam to operate steam turbine-electric generator combinations that are dedicated to each boiler. Figure II-2 shows the SLP with Unit 1 on the left. The units in the plant can be fired on coal or natural gas.

Figure II-2
View of the Silver Lake Power Plant

The SLP is required to operate within the guidelines of the Mid-Continent Area Power Pool (MAPP). The MAPP requirements include regular testing of the units in the power plant to make sure they can deliver the power that the RPU records for their capacity. These tests have shown that the plant has the capabilities shown in Table II-3:

Table II-3
Unit Data

Unit	Installed Date	Tested kW (2002)
1	1949	9,360
2	1953	14,520
3	1961	24,000
4	1969	61,945
	Total	**109,825**

Environmental

The SLP is operated to minimize environmental impacts to the Rochester area and in compliance with federal and state environmental regulations. The units are equipped with particulate controls. RPU purchases low bituminous sulfur coal for the plant to minimize the release of sulfur dioxide and comply with emission limits contained in the operating permit.

There are a variety of recently enacted and newly proposed regulations which will affect electric generating plants. The regulations will affect all generating units at the SLP. These regulations may require additional emission control equipment be added at the plant or changes to the fuel used for energy production.

RPU recently completed a study on the environmental aspects of the SLP with regard to existing and potential environmental regulations. It is expected that the RPU will need to make investments in additional emission controls or implement other emission reduction strategies within the next 5 years. Various options are currently under consideration by RPU. Estimated impacts to the SLP have been considered in this study using the results of the environmental report "Analysis of Existing and Potential Regulatory Requirements and Emission Control Options for the Silver lake Plant".

Due to the permit restrictions contained in the current air permit SLP, Unit 4 is limited to a 60-70% annual capacity factor. This will be significantly reduced if the recently proposed Interstate Air Quality Rule is promulgated and no modifications are made to the SLP.

Sales

The SLP has two contracts for energy sales. The MMPA contract provides for electrical sales to the MMPA when the units are available. The contract has various options for RPU to reduce the amount of capacity offered to MMPA. These options to adjust capacity allocated to MMPA under the contract are available in 2005 and 2010. The above balance of loads and resources reflect the current thinking of RPU on the amount of capacity which will be available to RPU from the contract.

The steam sales to the Franklin Heating Station are going to begin 2004. The steam sales are not anticipated to limit the electrical output of the steam generators until after the 2010 time frame. These reductions in electric capacity have been accounted for in the balance of loads and resources.

Retirement

Units 1-3 at the SLP will be attaining almost 65 years of service in 2015. Unit 4 will be reaching 45 years of operation. The investment in maintaining the units in operable condition has been estimated and included in the analysis. One of the major investments to be considered is the environmental controls required to keep the units in compliance with expected future environmental regulations. A recent study prepared for RPU by R.W. Beck and Associates has provided several options and their associated costs for the units with regard to compliance with anticipated future environmental regulations.

Although the components of the units can be repaired or rebuilt to keep the units in serviceable condition using after market providers and salvage operations from similar retired units, the efficiency of the units is below current technology being developed for coal fired power plants. Due to the age, size and efficiency of units 1-3, these units, if maintained, will most likely be used only for regulatory reserve service with minimal operating time.

Cascade Creek

The RPU has two units in the Cascade Creek substation. Cascade Creek Unit 1 was installed in 1975. The unit is a Westinghouse 251 machine and has a capacity rating of 28MW. Modifications to the unit in 2002 allow the unit to be operated on fuel oil or natural gas. The unit is reaching a point where replacement parts are becoming difficult to obtain. Aftermarket manufacturers can support the unit for some time. However, RPU plans on retiring the unit after 2015. The retirement of this unit will increase the deficit after 2015 by 28MW.

Cascade Creek 2 is a Pratt and Whitney FT8 Twin Pac, which became commercial in 2002. The unit is rated at 49MW. The unit consists of a single electric generator with dual engines based on aircraft engine technology. The dual engine approach allows the unit to be operated at half load with high efficiency. This flexibility minimizes operating costs when RPU needs resources to follow load more closely. This unit is assumed to be operational throughout the study period.

Zumbro River

The Zumbro River hydro-electric plant is a run of river unit located on the Zumbro River. The plant is located 10 miles to the north of the city. The unit was installed in 1919 and has a maximum capacity of 2MW. The unit has a typical annual capacity factor of 50 percent. Although the unit is over 80 years old, significant investment has been made in the facility and it is assumed to remain available throughout the study period.

Southern Minnesota Municipal Power Agency (SMMPA)

RPU began taking power supply from the SMMPA in 1982. The SMMPA provided all requirements service to RPU until 2000 when RPU accepted an offer to limit its purchases from the SMMPA. The contract rate of delivery (CROD) was set at 216MW. RPU is required to take all energy from the SMMPA when the demand is at or below the CROD level. The SMMPA will provide the CROD throughout the study period.

Transmission Issues

Electrical System Reliability

To operate reliably and in compliance with NERC and MAPP standards, RPU and other electric utilities developed their systems to operate with no noticeable degradation of service in the event of a loss of a system facility. In many cases, this is true even when an outage of a major system element coincides with the outage of another element for maintenance.

Changes in the electric industry over the past several years have caused the reliability of the system for delivery of firm energy to degrade. Increased use of the system for market transactions has increased loading of the system to the point that when outages occur, the remaining system is left with a reduced capability to transfer power over interconnections. Recent uncertainty in the ownership, operation and regulation of the transmission system has left the responsibility to correct system deficiencies in question.

RPU imports a significant amount of energy under its contract with the SMMPA. The transmission system which interconnects RPU to the regional transmission network is configured as indicated in Figure II-3. The strongest source to the interconnected network is through the Byron substation and is the primary path for the SMMPA energy.

With all of the lines in service, the system was designed to allow firm importation of the SMMPA energy whenever RPU called for it.

Recent changes in the usage of the system by others have led to curtailments of energy imports with the regional interconnections intact. An example of the transmission limitations that exist occurred on August 12, 2003 from 20:00 hours to 22:00 hours. RPU was required to generate because SMMPA was not able to secure transmission to deliver the energy required by RPU to meet loads. This condition is interesting because RPU's load was below the CROD level of 216 MW, for which RPU pays firm delivery. This condition is expected to escalate both in magnitude and frequency. Under current plans, no relief of the transmission situation in Southeast Minnesota is expected before 2010.

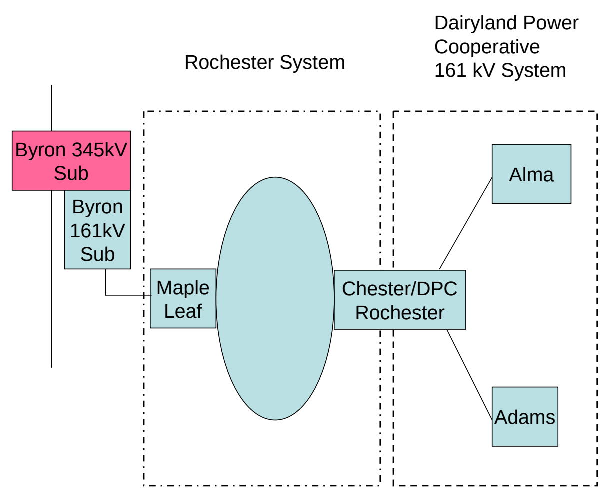
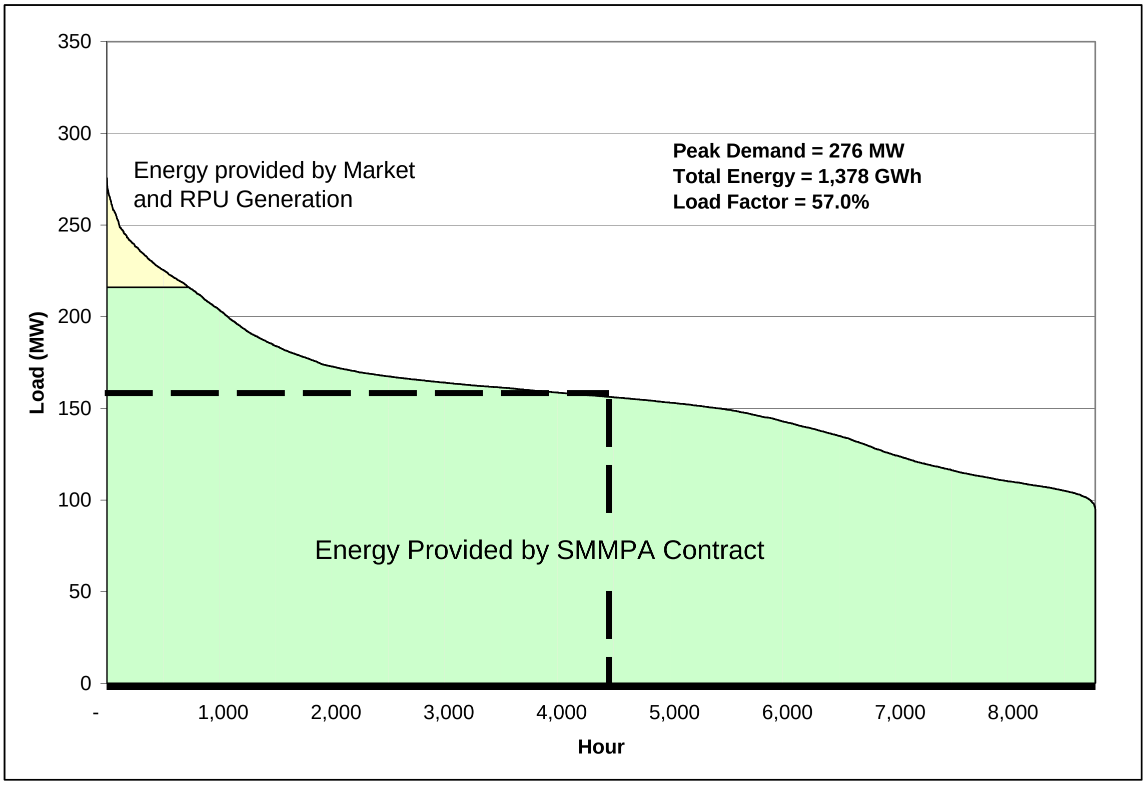


Figure II-3
Area Interconnections with RPU

With the Byron/Maple Leaf 161 kV line out of service, voltage and other considerations on the Dairyland Power Cooperative system limit the ability to import energy from the interconnected system to about 160 MW. Figure II-4 shows a load duration curve projection for 2005 for the RPU load. This curve shows the magnitude of the load in each of the 8760 hours of the year in order from highest to lowest. As shown, the RPU load alone is projected to be above the 160 MW level of import approximately 50 percent of the time. The use of generation internal to the area, such as the SLP is required to mitigate the risk of blackout during this condition.

Figure II-4
RPU 2005 Load Duration Curve



Another situation also requires the use of RPU generation to assist the area interconnected network. The rating on the Byron/Maple Leaf 161 kV line is a limiting factor in setting the transfer limit on the Byron 345 kV lines. The rating of these lines is a contributor to the calculation of the capability to import and export power from Minnesota to Wisconsin and points south and east. RPU, as a part of the interconnected system and with generation accredited in MAPP, is obligated to operate generation to assist these transfers during certain system outages. Running RPU generation is a partial mitigation for certain outages. While the RPU does not specifically benefit from this operation, it is an obligation that may be incurred from time to time.

The above discussion provides a description of the area interconnection limitations to which the community of Rochester is exposed. RPU faces several impacts due to these limitations. The SLP and Cascade Creek generating units assist in reducing the impacts and thus the costs to RPU and the community of Rochester. The increased reliability for Rochester is increased in numerous ways by the generation located within the service area of RPU.

The electrical wholesale market is moving towards a new market operation being promoted by the Federal Energy Regulatory Commission (FERC). The new operation is based on the concept of locational marginal pricing (LMP). The concept behind LMP is that the energy from generation required to alleviate a transmission constraint will be higher cost than the energy that could be imported if there were no constraint. Since Rochester is in a constrained load pocket, it could be subjected to substantial costs if the SLP or Cascade Creek generation was not available. The generation located in the RPU service area will reduce the exposure to market pricing and high LMP costs.

System Improvements

RPU is undertaking studies with regional utilities to assess options for reducing the constraints into the southeast Minnesota region and Rochester. Several transmission projects are being considered which will affect the 161kV and 345kV systems in the region.

The development of a project to increase the transfer capacity into the RPU service territory is important to allow RPU to rely on the firm delivery of its CROD amount. In addition, it is also desirable through the development of a project to have increased transfer capacity for importation of market power or participation in regional projects, such as for a coal or wind resource, on a firm basis.

Use of local generation is becoming more of an issue as regional loads increase and the capability of the transmission system becomes more limited. Due to must run issues during portions of the year and contract requirements of MMPA, the SLP is required to remain operational for the foreseeable future. The current limitations on the transmission system being below the level required to support the RPU load from outside resources point out the importance of generation internal to the RPU service area.

Potential Resource Options

The capacity needs of RPU are projected to increase substantially over the study period. The range of capacity needs is reflected in Table II-4 for various retirement scenarios of Cascade Creek Unit 1 and Silver Lake Plant Units 1-4.

Table II-4
Range of Capacity Requirements for Various Retirements Scenarios
(MW of Capacity Deficiency)

	2016	2020	2025	2030
All Units in Service	8	56	123	201
Retire CC Unit 1	36	84	151	229
Retire CC1, SLP 1-3	83	131	198	276
Retire CC1, SLP 1-4	128	176	243	321

In addition to an assessment of demand shortfalls, a review of energy needs is also necessary to determine if only peaking type resources are needed, or if low cost energy, reflective of intermediate or base load resources, is potentially beneficial. Figures II-5 A through C provide the estimated load duration curves for RPU for the years 2005, 2010 and 2015, respectively.

Figure II-5A
Approximate RPU Load Duration Curve
2005

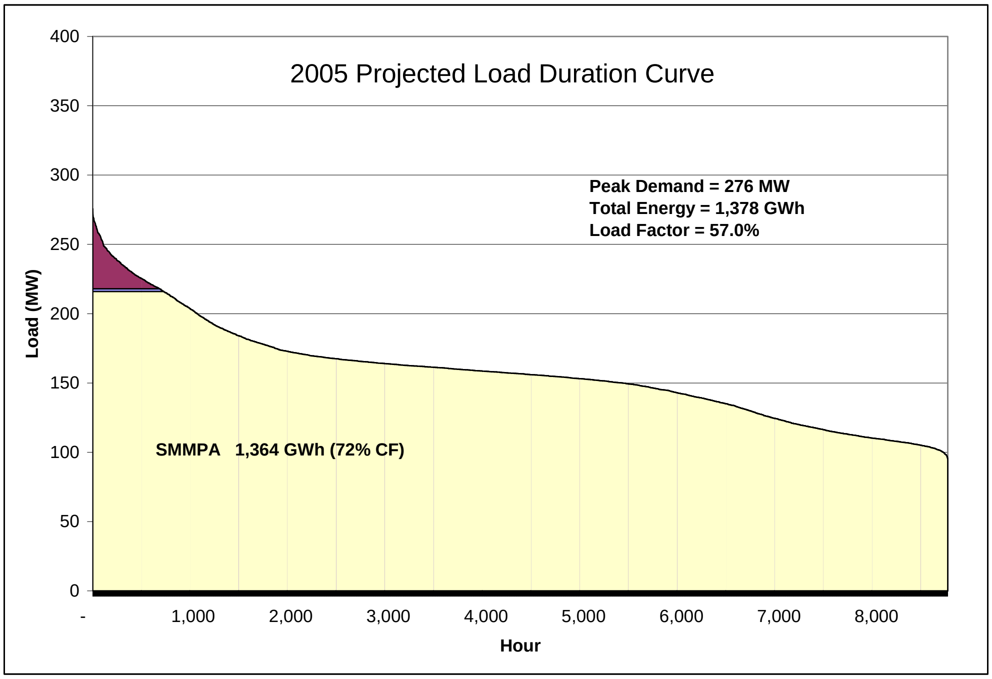


Figure II-5B
Approximate RPU Load Duration Curve
2010

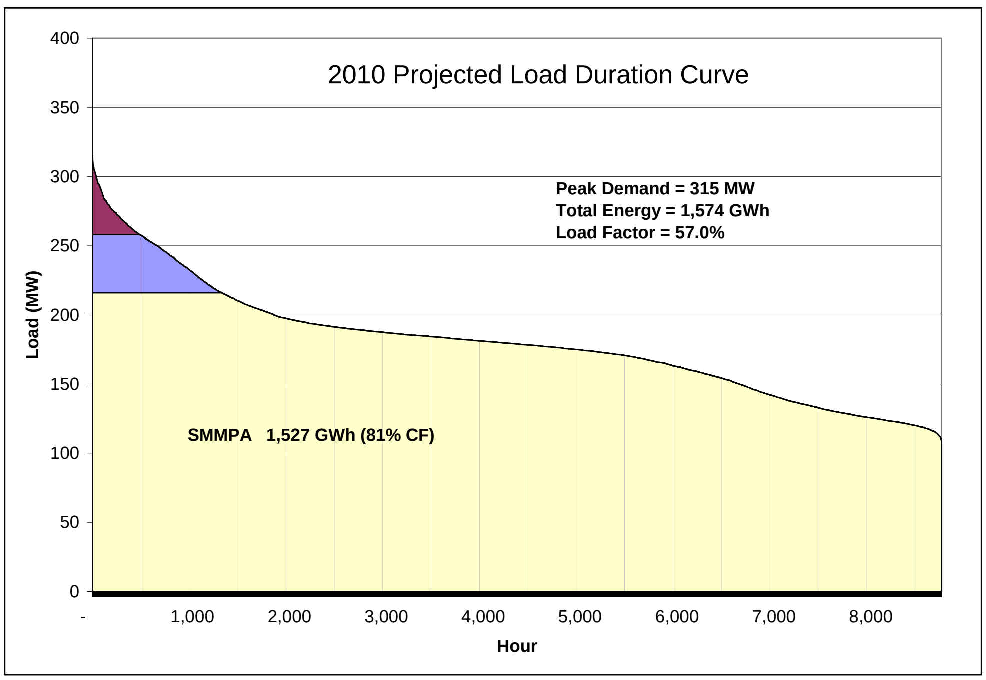
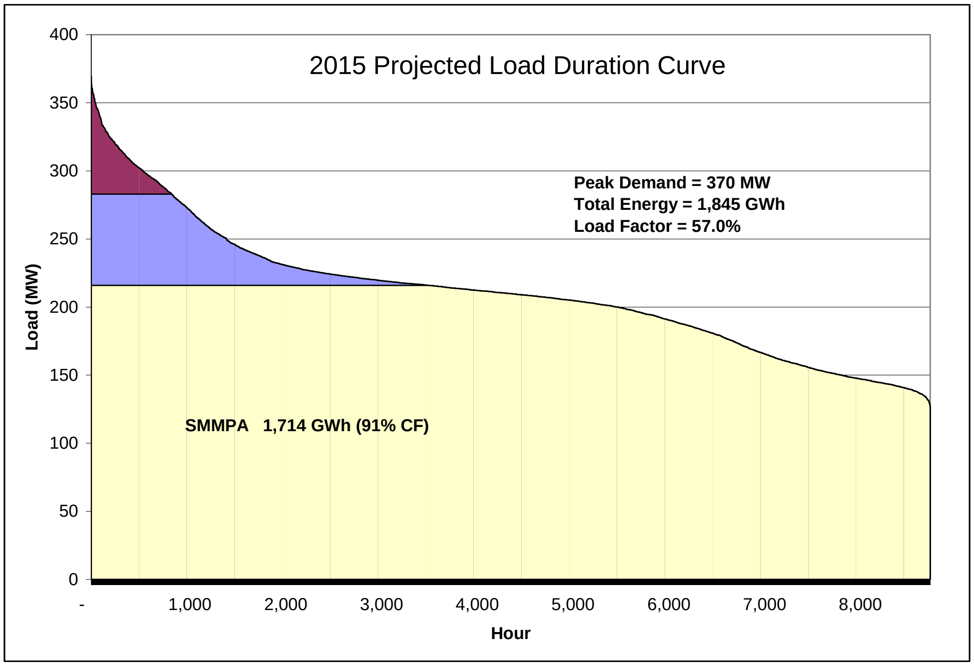


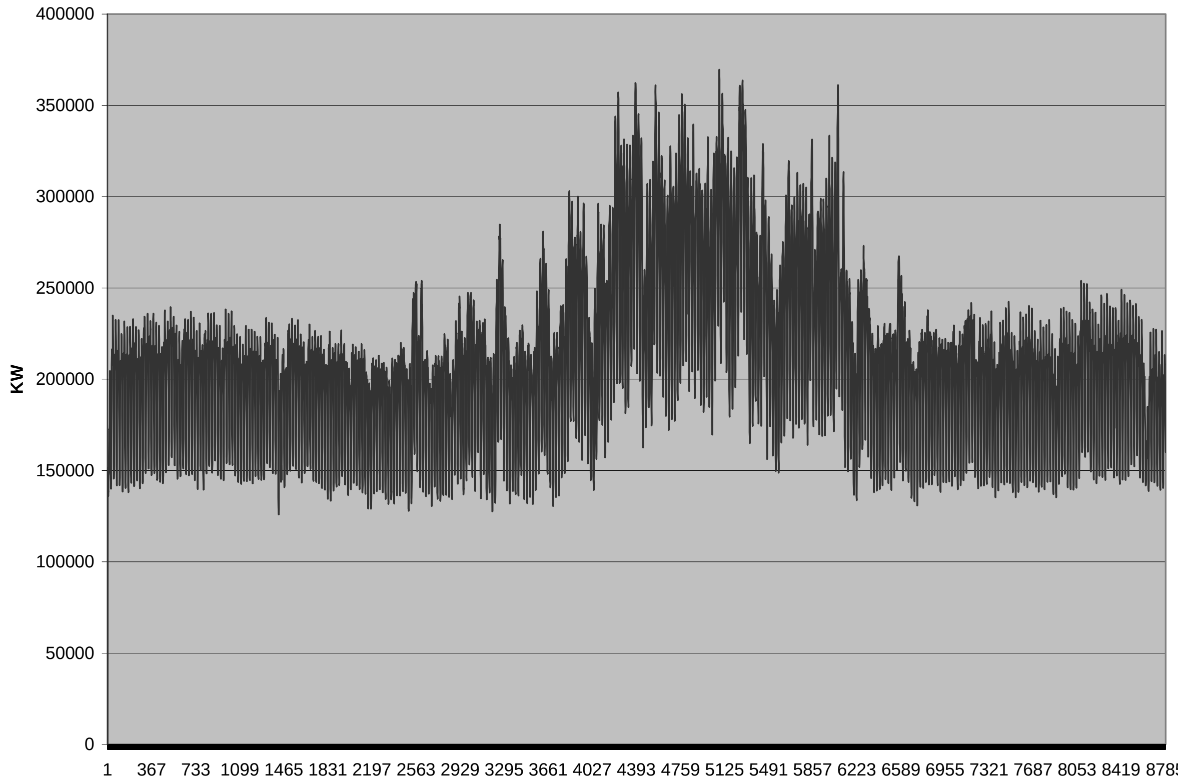
Figure II-5C
Approximate RPU Load Duration Curve
2015



A review of the load duration curves indicates that the SMMPA CROD level would approach its maximum utilization in the 2010 to 2015 time frame. The energy (represented by the colored areas above the SMMPA energy) would be provided by RPU. Therefore, in addition to capacity needs, RPU will also need to consider the availability of low cost energy resources for the period beyond 2016.

The projected hourly loads for RPU during the year 2016 are shown in Figure II-6. Review of the hourly loads indicates that the majority of the RPU needs occur in the summer months, between May and September. There are several hours when the load will be below the CROD level. This indicates that resources may need to be cycled if load following is required.

Figure II-6
RPU Projected Hourly Load – 2016



The operational issues associated with meeting the projected RPU load requirements can also be reviewed by looking more closely at the load swings. Graphs for the hourly loading during winter and summer weeks are shown in Figures II-7A and B respectively for every five years from 2016 to 2030. The growth in the daily swings from winter to summer provide an indication of the seasonal types of energy needs which RPU will be required to provide. The load on the figures is the load above the CROD amount. Therefore, the zero point on the vertical axis represents a load of 216MW, provided by the SMMPA contract.

Figure II-7A
RPU Projected Hourly Loads Week of January 1-7

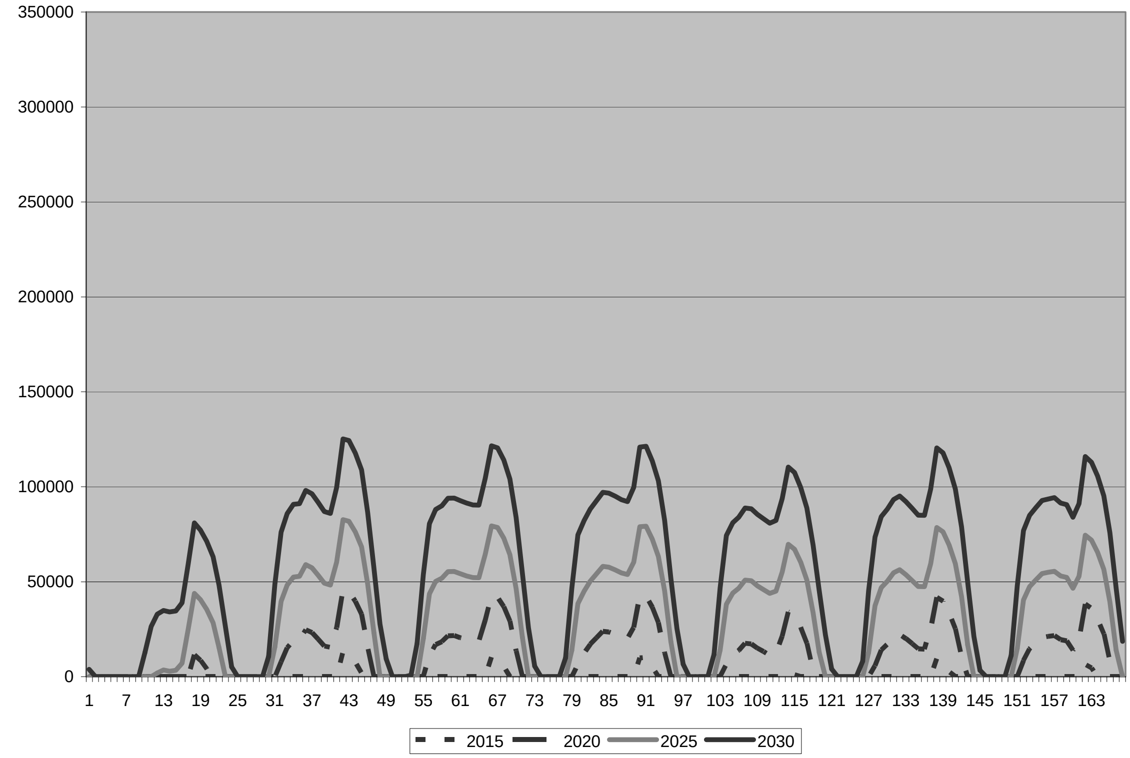
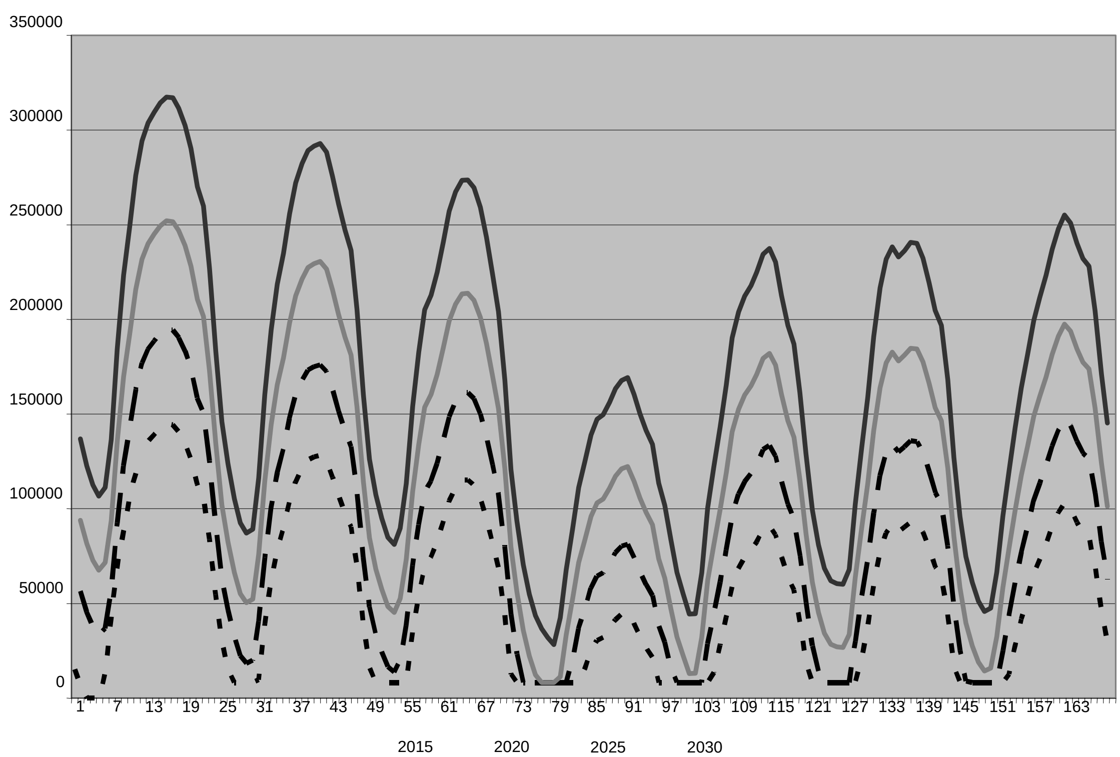


Figure II-7B
RPU Projected Hourly Loads Week of July 1-7



Fuel Considerations

The availability to develop resources within a utility's service area requires a review of area capabilities for the delivery of low cost fuel for the units. Current utility options for fuel include coal, natural gas, fuel oil, water, and renewable options such as solar, wind and biomass.

Coal

RPU currently burns coal at the SLP facility. The coal is delivered by barge/truck and rail, with approximately 50 percent delivered by each method. It is not expected that the consumption of coal will increase beyond the limitations of the permits for SLP Unit 4. If RPU pursued the development of an additional coal resource within its service area, rail facilities to deliver the coal from the Powder River Basin in the west or from eastern mines, besides those currently available from Illinois and Indiana, would need to be expanded. Currently, the RPU service area has a rail line being reactivated which would allow delivery of Powder River Basin coal. Acquisition of several hundred acres of property adjacent to the rail line would be required or a rail loop would have to be constructed if the property was located remote from the rail line.

The use of coal by the utility industry is expected to increase. Its availability within the United States has certain security advantages. Its price has been historically low and stable when compared to natural gas and fuel oil. Its main disadvantage lies in the emission during its combustion. New requirements are increasing the controls necessary on new coal plants to reduce the emissions to levels that are approximately one tenth of units constructed under prior Clean Air laws.

Natural Gas

The use of natural gas in new utility plant is typically limited to simple or combined cycle applications. Modern gas units require gas pressures typical of interstate lines. Additional gas based resources for RPU would require the acquisition of additional property, since the existing Cascade Creek site is fully utilized and the SLP site has inadequate gas capacity. Modern units could be placed on a site of less than one hundred acres.

The historical availability of natural gas has been such that it was abundant in the summer months when residential and commercial heating demands were low and subject to interruption during the winter when the heating demands increased. When utilities developed the peaking gas resources, they were typically required in the summer with minimal expectations for operation in the winter. Utilities relied on this pattern and purchased the gas on a non-firm basis to reduce delivery costs. For the minimal hours of operation in the winter, back up operation on fuel oil could be relied on if the gas delivery was curtailed.

Recent demands for peaking and combined cycle energy fired from natural gas in both the summer and winter have increased to the point where the electric utilities are affecting the storage and availability of natural gas. In addition, due to environmental restrictions, more natural gas is used by many utilities to achieve compliance with their operating permits, which occurs primarily in the summer months. The use of non-firm purchasing approaches to the gas is becoming more of a problem in the winter months as utilities are required to provide increasing amounts of energy from these units to meet winter demands.

Dependence on natural gas by the utility industry has become more of a concern as the United States becomes an importer of the fuel from Canada and through liquefied natural gas ports from other countries. The cost of gas is expected to remain volatile and increase with the increasing demand for it by other countries as their economies improve. It is expected that over the study horizon, natural gas costs will not only increase due to commodity pressure, but from the need to firm up the delivery as well.

Other Options

The use of fuel oil is only considered on an emergency basis or when its cost is below the cost of natural gas. Emissions from use of fuel oil in electric plants typically restrict its use to few hours of the year. It is not considered as a basis for any resource expansion plan for RPU.

RPU and the surrounding regions do not have significant access to hydro-electric based development. The current hydro resources are fully committed. One area of potential access to hydro-electric power is the further development by Manitoba Hydro of projects that have been considered for several years. Access to this energy would require significant improvement in the region's transmission facilities.

Renewable resources are an increasing source of energy for utilities. Wind is the primary source and Minnesota has several hundred megawatts of wind in operation and more is being developed. In addition, wind resources are being developed in the neighboring states of Iowa, South Dakota and North Dakota are developing wind resources. Solar is becoming an increasing option for higher cost utilities on the east and west coasts as the cost of solar systems decrease and the cost of the utilities' energy increases.

A consideration for the use of solar and wind is the inability to dispatch the resource. Variability and availability of the energy can create operational issues with area generating units and can lead to a degradation of frequency and voltage control if the amount of solar and wind energy becomes a high component of the utility's energy needs. The inability to dispatch the resources has to be considered with regards to the CROD requirements.

Biomass is another option for renewable energy. Biomass plants are typically rated below about 50MW and operate in a steam cycle similar to the SLP plants. The candidates for biomass are typically;

- wood chips and other tree product residues,
- agricultural wastes such as fruit pits and nut hulls, and
- grasses.

The limiting factor on the development of a biomass plant is the availability of fuel. These plants are developed in areas where there is a continuous, ready availability of the fuel. Due to the poor storage capabilities of most of the candidate biomass fuel options, a continuing supply of quality fuel is necessary to make the process viable. The regional surrounding RPU is not known to have an adequate supply of typical candidate biomass fuels.

However, there is one area where RPU may have access to a limited amount of biomass fuel. Minnesota has also included municipal solid waste as a biomass fuel under Minnesota 2003 Statute 216. Therefore municipal waste and refuse derived fuel (RDF) burned in a power plant will be counted as biomass energy. The availability of RDF is typically sufficient in municipal areas the size of Rochester to support several megawatts of RDF fired generation.

Olmsted County has developed a municipal solid waste to energy facility. The Olmsted Waste to Energy Facility (OWEF) currently produces approximately 1.9MW of biomass fueled energy. This resource could be a source of biomass energy for RPU.

Summary

The RPU is confronted with several long term decisions associated with its generation and transmission resources. Based on the review of the resource issues as identified in this part, the following observations can be developed.

1. The projected load growth indicates that the CROD obtained from the SMMPA will essentially be fully utilized in the 2010 to 2015 time frame.

2. The SLP facility will be subjected to environmental regulations being implemented and future regulations under consideration. The cost of these regulations, the ongoing maintenance costs, sales obligations and the efficiency of the existing units require an assessment of an RPU future with varying amounts of the SLP available.

3. The RPU transmission system supplying RPU is currently inadequate to deliver the firm requirements of the CROD amount and to be relied upon to provide firm access to outside resources. Therefore, any reliance on resources outside the RPU area for firm energy will require the upgrading of the system in the vicinity of RPU. Depending on the location of any resource in which RPU may want to participate or purchase capacity from, upgrades of the regional system may also be required.

4. RPU capacity needs include resources to provide low cost capacity and energy over the study period. The ability to acquire the capacity and energy from outside the RPU service territory or the need to locate resources within the service area will be dependent on the transmission system upgrades pursued in the region by regional utilities.

5. The existing RPU generation locations do not have adequate space or access to fuel and transmission to support significant additional facilities. RPU will need to acquire additional property to support most types of generation options constructed within its service area.

6. RPU has options for development of wind and solar units and purchasing biomass energy from the Olmsted Waste to Energy Facility for renewable resources.

7. The market changes in the electric industry surrounding RPU will impact the resource decisions. Due to the uncertainty associated with the implementation of the MISO market, the level of participation by regional utilities, and the rules which participants will be required to follow, it is difficult for any firm conclusion to be made on the availability of market capacity and energy as a reliable resource which could be used by RPU to meet its needs.

*****

Part III

Resource Options Analysis

Part II provided a review of the expected capacity and energy needs of RPU over the study period. From the review, RPU is expected to have needs for both capacity and low cost energy resources beginning in 2013 and increasing each year thereafter. Additionally, a discussion of the existing resources indicates that the Cascade Creek Unit 1 is anticipated to be retired in 2015. Also, the future of the SLP is uncertain due to the age of the facilities and the ongoing operation, maintenance and environmental upgrades needed to keep the plant operational. This part of the report discusses portfolio options considered for RPU using traditional resource options.

Regional Market Conditions

Coal Unit Development

RPU's projected need for low cost energy limits the traditional options for supplying this energy to energy produced by coal. The amount of capacity required by RPU is expected to be in the 50 to 100MW level. In order to attain reduced capital and operating costs, it is typical for utilities to join and construct a unit to be shared among several parties. Therefore, the ability for RPU to obtain coal energy is realistically dependent on participating in a joint facility.

The MAPP region maintains a 15% reserve margin and penalizes those utilities who fall below this level. As such, the capacity margins in the MAPP region are projected to be maintained to have sufficient generation available to meet unit outages and weather extremes. The generation used to meet the reserve margin in the MAPP region, as in other regions, has primarily been natural gas fired simple and combined cycle combustion turbine units. There are coal plants being considered in the MAPP region. Plants are being developed by the following entities:

- OPPD – 600MW Nebraska City 2. Participation in the unit is through contract sales. The unit is fully subscribed.
- South Dakota – A large coal plant in eastern South Dakota is being considered by regional utilities. Participation will be through ownership shares.
- Mid-American Energy – Council Bluffs Unit 4. Participation is through ownership shares. The unit is fully subscribed and under construction.

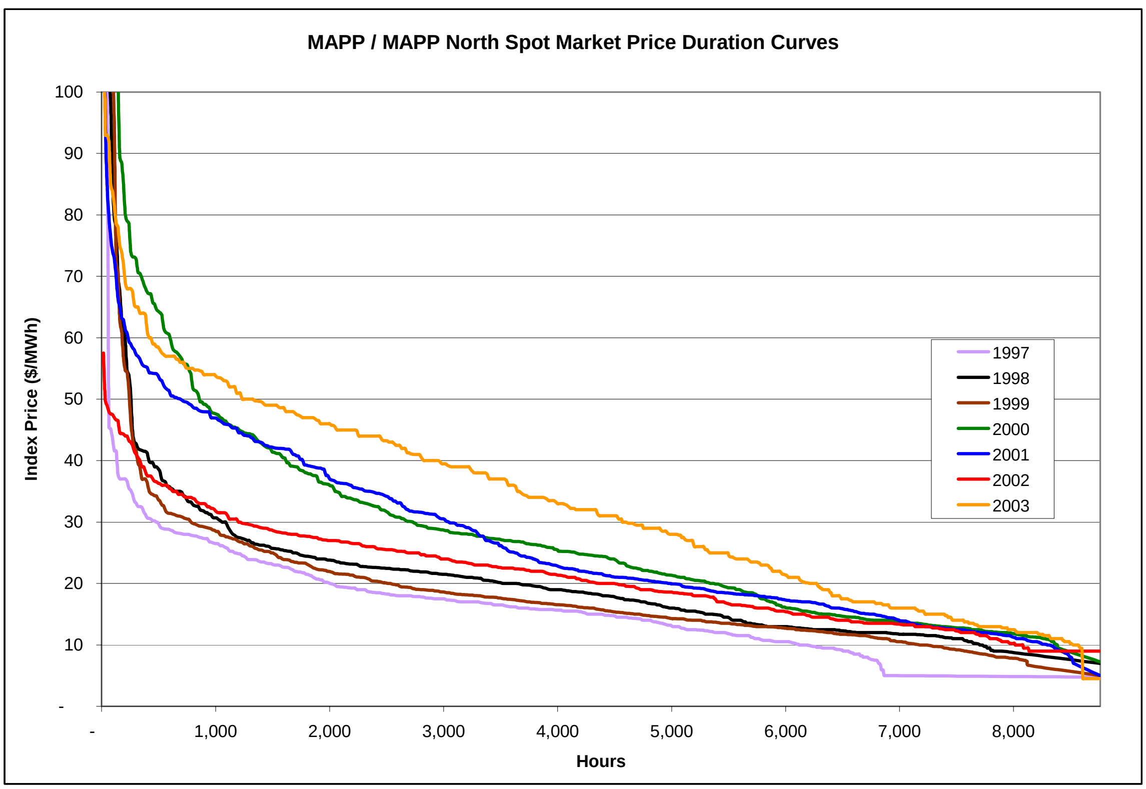
These plants are all located on the west side of MAPP. Significant transmission constraint and operational issues would need to be resolved before reliable firm service could be provided to RPU from these facilities. There are other utilities discussing units in MAPP which may offer reduced transmission delivery issues to RPU. In addition, RPU could join with other interested parties and develop a unit which could be sited more beneficially to RPU and have an in service date more in line with the needs of RPU.

Market Pricing

The power supply market in the MAPP regional is undergoing significant change. The Midwest Independent System Operator (MISO) is gaining operational control of a significant amount of transmission as utilities comply with orders of the Federal Energy Regulatory Commission (FERC) for regulated utilities to transfer operational control of their transmission systems to an independent operator. Additionally, MISO is furthering the FERC agenda of implementing a standard market design for the wholesale market. The operational rules of this market are currently being developed and the MISO is working towards implementation of the market by January 1, 2005. It is expected that this schedule will slip due to the numerous issues still to be resolved.

The MAPP regional has traditionally had a surplus of low cost energy. The pricing of this energy is increasing to reflect the marginal price of the combined cycle units that have recently been commissioned in the region and the need for additional base load facilities. Figure III-1 provides an indication of the increase in MAPP prices for the north region. The graphs reflect the increase in pricing due to the increased reliance on natural gas for electricity production.

Figure III-1
MAPP Spot Energy Pricing 1997-2003



The development of portfolio options for RPU considered the availability of a coal plant for RPU participation.

Resource Requirements

Portfolios were developed to reflect the decision tree issues associated with the following availability of the SLP beyond 2015:

- SLP fully retired
- Units 1-3 retired, Unit 4 remains operational
- All SLP units available

In addition, the retirement of the Cascade Creek Unit 1 was assumed to occur in 2015. The retirement of this unit increases the capacity required by 28MW in the study period.

Figures III-2 through 4 shows the balance of loads and resource for each of the above SLP futures.

Figure III-2
RPU Balance of Loads and Resources –No SLP

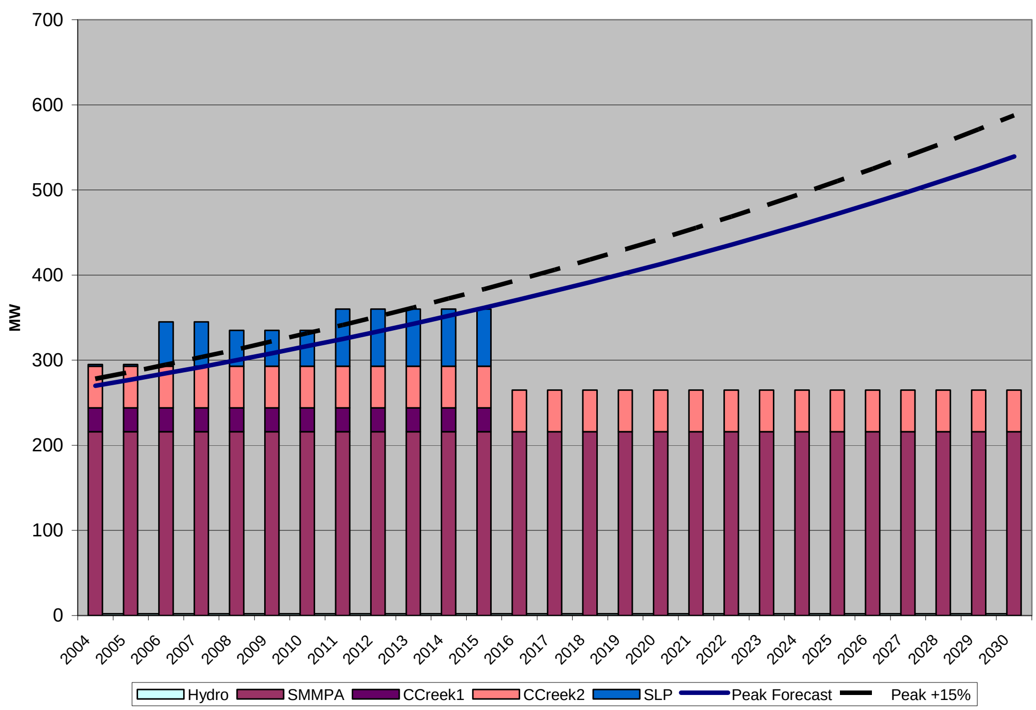


Figure III-3
RPU Balance of Loads and Resources -45MW of SLP

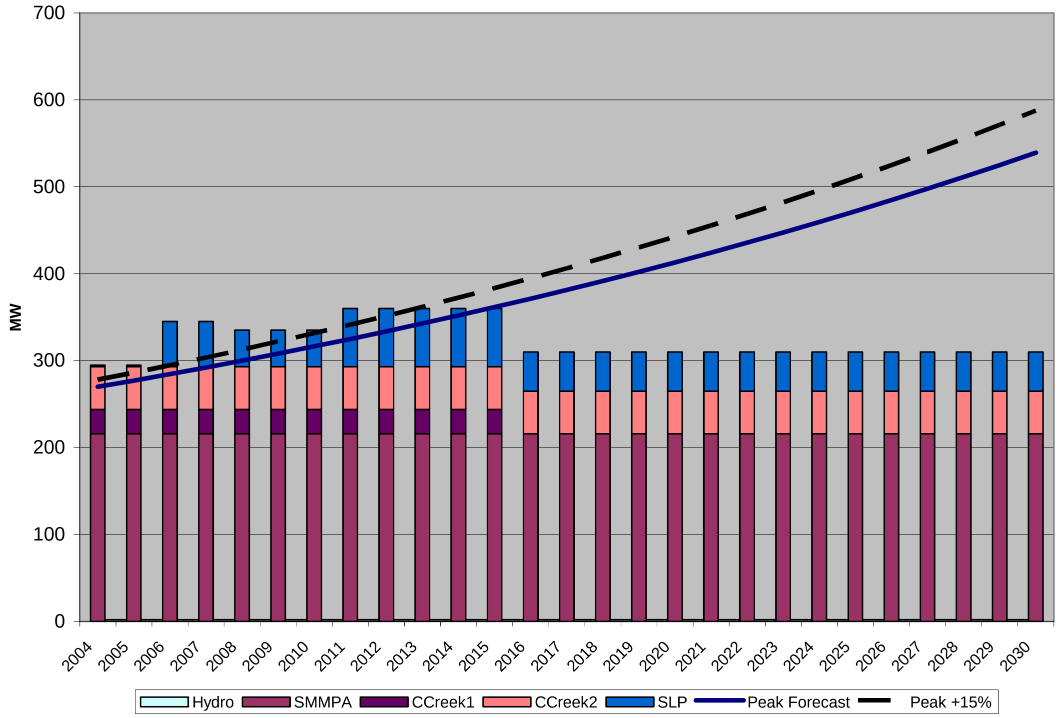
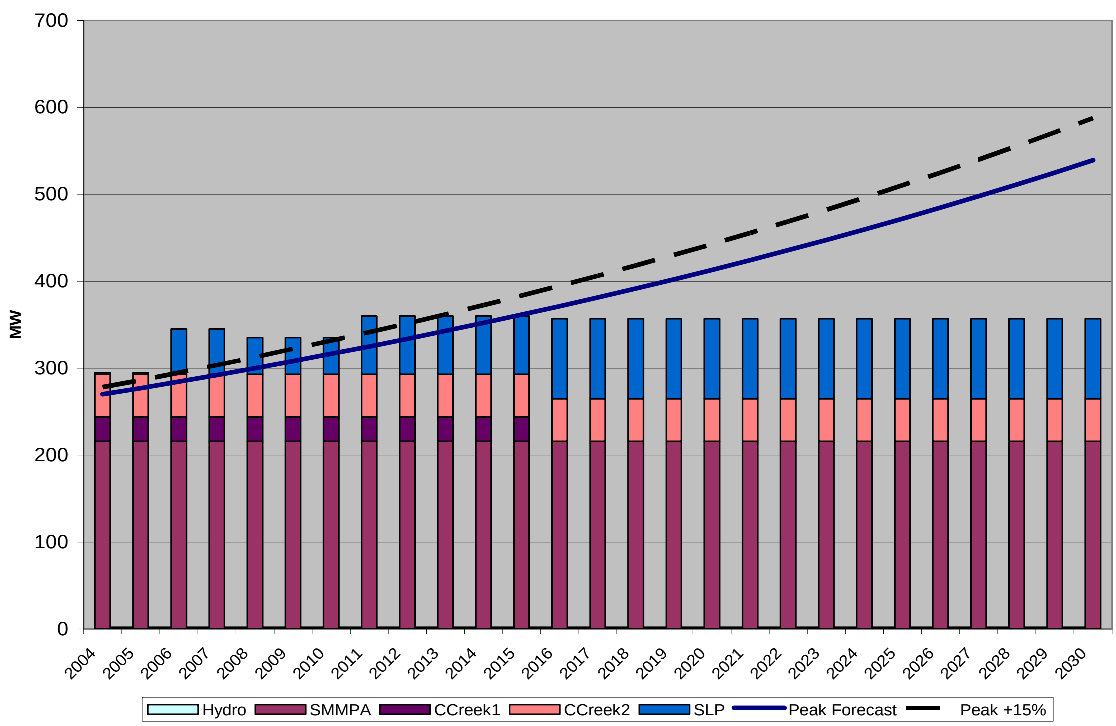


Figure III-4
RPU Balance of Loads and Resources –All SLP



The resource requirements were developed to maintain the reserve requirements of RPU. The current level of reserves is required by MAPP to be 15 percent of the amount of load requirements above the CROD amount.

Traditional Options

The traditional options included new resources fueled by coal and natural gas. These options are discussed in more detail in the following paragraphs.

Gas-Fired Options

Gas fired generation today is performed by combustion turbines operating in simple cycle or combined cycle mode. Simple cycle combustion turbines operate similar to jet aircraft engine technology. These units vent their exhaust direct to a stack and typically have efficiencies above 10,000 Btu per kWh. Combined cycle units include the simple cycle machine with its exhaust vented into a heat recovery steam generator (HRSG) and then through a stack. The steam produced by the HRSG drives a steam turbine/electric generator combination as in a typical steam driven plant. Combined cycle plants have efficiencies in the upper 6000 Btu per kWh range.

RPU currently operates two simple cycle combustion turbines. The new unit added at Cascade Creek is the latest to be added to the system. These units are typically operated when the load increases on the system during a few hours of the day. Simple cycle units typically have the lowest capital cost of larger generating options. Project costs in the range of $400 to $600 per kW are typical, with the smaller units having the higher cost per kW. Due to their efficiency, these units are typically operated at capacity factors below 15 to 20 percent.

Combined cycle plants have higher capital costs than simple cycle machines, due to the steam cycle cost. Project costs for these machines range from $500 per kW to $750 per kW, again with the smaller plants having the higher cost per kW. These plants have been the predominate plant installed by merchant independent power producers over the past few years and are expected to account for the majority of the installed capacity for the foreseeable future. Since these plants operate at higher efficiencies, they operate at capacity factors above those of simple cycle machines and are typically between 25-50%.

Gas-fired combustion turbines have nitrous and carbon oxides as their main emissions. Simple cycle units use water in emission control and in inlet air fogging systems. Combined cycle units also use water in cooling cycles for the steam condensing and boiler makeup.

The existing gas fired generation on RPU's system is used primarily for peaking and reserve service. The gas supply for these units is operated on a non-firm basis. Operating with a non-firm fuel supply allows the energy to be produced for essentially the cost of the gas commodity and a small delivery charge. RPU could develop gas-fired units within its service territory without the need for partners due to the lower effect of economies of scale.

Coal-Fired Options

Traditional coal-fired steam power plants are being considered for electricity production again as the cost of natural gas and the concern over its availability increases. Coal-fired plants, such as RPU's Silver Lake Plant, burn coal to produce steam which drives a steam turbine/electrical generator to generate electricity. Coal plants are being designed to reduce the emissions from the coal burning process to very low levels. Facilities added to clean the exhaust path include scrubbers to remove the sulfur dioxide, baghouses to remove the particulates and selective catalytic reduction equipment to remove nitrous oxide. Processes are being developed to also reduce the mercury in the exhaust.

To achieve economies of scale, coal plants are typically above 250 MW in capacity. At this size, there are two combustion types, fluidized bed and pulverized coal. There are major differences in the boiler and plant design for the two units. The main difference is in the method to control sulfur emissions. The fluidized bed units blend limestone in the combustion chamber to achieve reductions in the sulfur emissions. Pulverized coal units use scrubbers to inject lime into the exhaust stream and remove the sulfur. The SLP coal units are pulverized coal units. The current upper commercial limit on the fluidized bed units is 250 MW.

Coal plants typically operate with capacity factors of 60-80%. In order to achieve these economies of scale, a joint owned unit would be required or RPU would have to enter into contract sales to support the costs of the facility until the entire plant could be used for RPU requirements.

It is assumed that any new plant would burn coal from the Powder River Basin. However, new facilities are considering bituminous coal from the east as it is easier to remove the mercury from the exhaust stream. A coal plant developed by RPU could be served by the Dakota Minnesota and Eastern railroad, which is extending its system into the Powder River Basin. Another area option might be the Union Pacific line. Expansion of the rail system would be needed if an additional unit is located in RPU's service territory. No specific siting assessment has been performed for this option.

Traditional Resource Portfolios

Considering the capacity needs for the SLP availability scenarios, the resource portfolios shown in Table III-1 were developed.

Table III-1
Resource Portfolios

	Existing Capacity - MW			Capacity Added - MW(year installed)				
Case	CROD	Other	SLP	Coal	Combined Cycle	Twin Pac		
None216-100Coal	216	51	0	100(15)		50(15)	50(20)	50(25)
None216-50Coal	216	51	0	50(15)		100(15)	50(20)	50(25)
None216-100CC	216	51	0		100(15)	50(15)	50(20)	50(25)
None216-LMS100	216	51	0		100(15)	50(15)	50(20)	50(25)
None216-SC	216	51	0			150(15)	50(20)	50(25)
45216-50Coal_CoalFirst	216	51	45	50(15)		50(15)	50(20)	50(25)
45216-50Coal_SLPfirst	216	51	45	50(15)		50(15)	50(20)	50(25)
45216-100CC	216	51	45		100(15)		50(20)	50(25)
45216-LMS100	216	51	45		100(15)		50(20)	50(25)
45216-SC	216	51	45			100(15)	50(20)	50(25)
All216-50Coal_CoalFirst	216	51	92	50(15)			50(20)	50(25)
All216-50Coal_SLPfirst	216	51	92	50(15)			50(20)	50(25)
All216-100CC	216	51	92		100(20)	50(20)		
All216-LMS100	216	51	92		100(20)	50(20)		
All216-SC	216	51	92			50(15)	50(20)	50(25)

The case titles are developed such that the None, 45 or all refers to the amount of SLP capacity available, 216 refers to the CROD amount and the last numbers refer to the MW of resource added. SC refers to simple cycle, CC refers to combine cycle, and LMS 100 refers to a new simple cycle unit being developed. References to CoalFirst and SLPFirst are associated with the order of dispatch.

The simple cycle units considered are based on the current Cascade Creek Unit 2 type facility, the Pratt and Whitney Twin Pac. The combined cycle unit is based on a purchase of a 125MW portion of an area combined cycle project. The coal resources are assumed to be from a regional project whereby RPU would purchase the indicated amount as an owner.

Transmission delivery charges for the coal plant were included to provide an assumption on the MISO transmission service fees. No transmission was assessed the combined cycle unit or the simple cycle units as they were expected to be constructed within RPU's service territory.

Hourly and monthly production cost models were developed that dispatched the resources on an economic dispatch basis, considering limitations on energy from Unit 4. Assumptions for the new and existing units are included in Appendix II.

The energy to supply the RPU projected load growth is summarized in Table III-2 for the coal and gas resource options. The load curves produced in Part II provide an indication that the energy is more heavily utilized in the summer season than the winter period.

Table III-2
Summary of Energy Sources from Gas or Coal Portfolios

Energy in GWh	2016		2020		2025		2030	
	Gas	Coal	Gas	Coal	Gas	Coal	Gas	Coal
None216-100Coal	3	1,839	21	2,023	72	2,257	171	2,490
None216-50Coal	36	1,806	79	1,965	187	2,142	423	2,238
None216-Gas	121	1,721	248	1,796	479	1,850	773	1,888
45216-Coal	4	1,838	25	2,019	79	2,250	187	2,474
45216-Gas	34	1,808	93	1,951	243	2,086	536	2,125
All216-Coal	4	1,838	25	2,019	79	2,250	187	2,474
All216-Gas	34	1,808	93	1,951	243	2,086	536	2,125

Note: Above numbers do not include a negligible amount of hydro energy

The above table reflects the energy estimated to be taken from the various generation resources within the respective expansion portfolios. The energy in the gas columns includes energy generated by RPU and purchased from the market. The coal energy includes that purchased from SMMPA and generated by RPU. As seen, where the coal energy is limited to the existing resources, significant increases in the gas energy is necessary. It should be noted that all of the cases include additional gas-fired resources.

The cases that are based solely on natural gas-fired resource additions would require a gas supply adequate to provide approximately 3056 MCF of gas per hour at approximately 600psi when all of the units are operational in 2030. The RPU gas consumption in 2030 with one of the all gas portfolios would be approximately 5360 million cubic feet. Even though a portion of the gas requirements are expected to be met by market purchases, it is considered that the energy provided by the market would also be gas based. Therefore, even if the gas is not directly used by RPU, it will be required by the regional generation providing the market energy.

Production Cost Results

The results of the production cost modeling for the traditional portfolios are summarized in Table III-3. The net present values for the cases were developed for the 15 year study horizon in 2015 dollars. The values shown reflect the incremental costs of each option and, therefore, do not include all of RPU's costs which would be common among all of the cases.

Table III-3
Summary of Net Present Values for Portfolio Options
(2015 $000)

		% Below Base
45216-LMS100	$320,892	-
45216-50Coal_CoalFirst	$325,782	1.52%
All216-50Coal_CoalFirst	$327,201	1.97%
45216-50Coal_SLPfirst	$328,750	2.45%
All216-50Coal_SLPfirst	$330,169	2.89%
None216-50Coal	$342,102	6.61%
All216-LMS100	$347,789	8.38%
45216-SC	$347,544	8.31%
All216-SC	$351,098	9.41%
None216-100Coal	$353,725	10.23%
None216-LMS100	$362,430	12.94%
None216-SC	$387,146	20.65%
All216-100CC	$389,434	21.36%
45216-100CC	$396,788	23.65%
None216-100CC	$435,755	35.80%

The above portfolios all have a mixture of coal and natural gas resources used to minimize RPU's overall average energy costs. The results indicate that the availability of low cost energy from the SLP unit 4 or an additional coal plant purchase is a lower cost scenario than relying only on natural gas for the energy needs above the CROD level. Details for each of the above cases can be found in Appendix III.

Summary

Based on the evaluations of several traditional resource options, Burns & McDonnell offers the following conclusions about resource expansion plans.

1. The addition of capacity is required to meet the MAPP reserve requirements and to satisfy RPU's obligation to serve its load requirements over the period 2016 to 2030.
2. The review of traditional additions of natural gas and coal-fired options indicates that the addition of coal capacity decreases the exposure to the supply and price risk of natural gas.
3. The scenarios with SLP remaining operational provide lower evaluated costs than the total retirement of SLP.
4. The lower cost scenarios include the addition of a 50MW value of coal capacity or a low capital cost combined cycle type resource along with continued investment in Twin Pac type combustion turbines to meet peaking needs.

5. RPU will need to participate in a coal project to acquire the 50MW portion with any economies of scale. The exposure to transmission congestion and delivery problems would be reduced if the plant was developed in or near the RPU service area.
6. The gas based resources can be developed solely by RPU. Consideration of the capabilities of the gas infrastructure for the Rochester area will have to be reviewed closer to the time that the facilities are needed to determine if pipeline capabilities need to be expanded to support the expected gas demand.

Based on the above conclusions, the lower cost options from the traditional resource portfolios were reviewed in greater detail in Part IV.

*****

Part IV

Economic Analysis of Preferred Options

The development of the power supply options in Part III identified several low cost evaluated options for RPU to consider in the long range planning. The lower cost plans included a mix of coal and gas-fired resources to minimize the average energy costs. With the long term plan identified, decisions on the near term issues can be made with more certainty on their long term affects on RPU's rates. This part of the report provides a closer assessment of the long range options and provides recommendations on the near and longer term power supply paths which RPU should pursue.

Options for Review

The lower cost evaluated options for RPU in Part III are shown in Table IV-1. The options included reflect the various scenarios considered for the SLP plant.

Table IV-1
Lowest Evaluated Cost Traditional Resource Portfolios

		% Below Base
45216-LMS100	$320,892	-
45216-50Coal_CoalFirst	$325,782	1.52%
All216-50Coal_CoalFirst	$327,201	1.97%
45216-50Coal_SLPfirst	$328,750	2.45%
All216-50Coal_SLPfirst	$330,169	2.89%
None216-50Coal	$342,102	6.61%

The options include the following characteristics:

- Coal energy is provided through SLP for the lower cost cases, with the possible addition of a 50MW amount.
- Gas resources include simple cycle combustion turbines similar to the Twin Pac unit and an efficient unit with low capital and operating costs, represented by the LMS100 unit currently becoming commercial from GE.

The options were evaluated with certain assumptions subjected to modification over a range. The analysis used the @risk software from Palisades. The factors subjected to variation are summarized in Table IV-2.

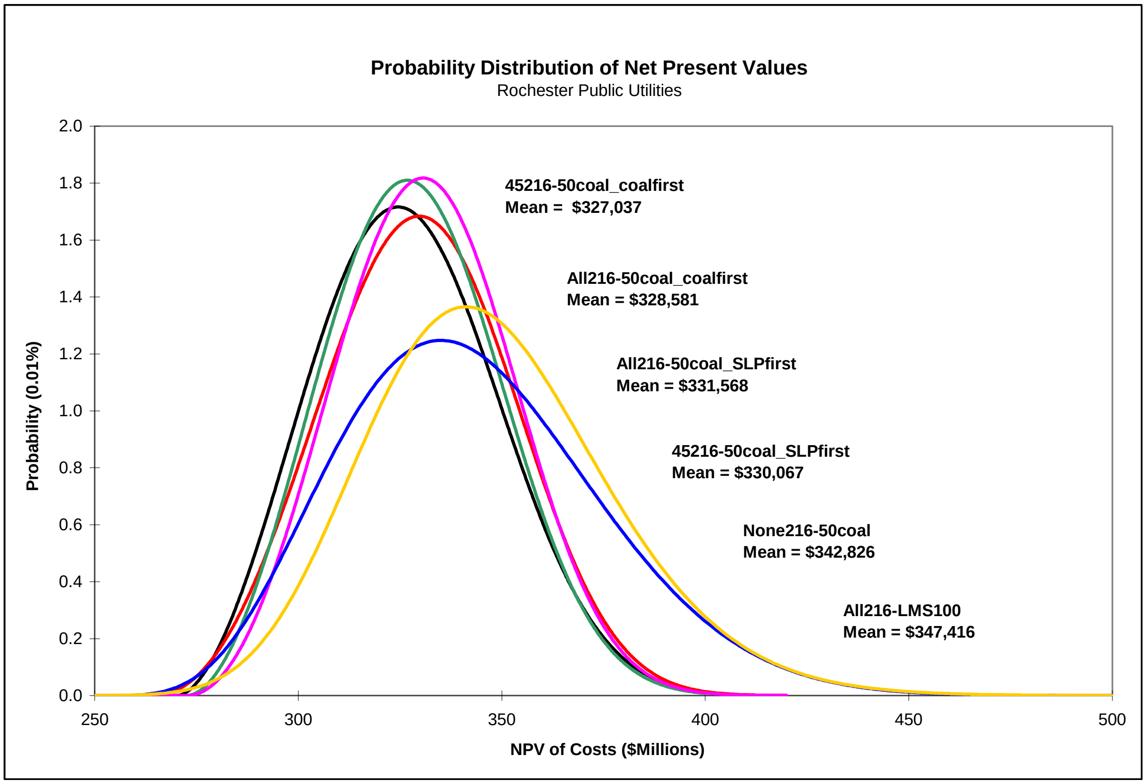
Table IV-2
Assumption Variations Used to Evaluate Lower Cost Resource Portfolios

	Min.	Likely	Max.
Load Escalation	2.0%	2.7%	3.4%
Fuel Prices			
Gas Commodity 2006 Price ($/MMBtu)	$3.62	$4.82	$7.23
Gas Commodity Real Escalation	0.0%	1.0%	2.0%
Gas Transportation 2006 Price ($/MMBtu)	$0.32	$0.42	$0.53
Gas Transportation Escalation			
Coal Commodity 2006 Price ($/MMBtu)	$0.35	$0.41	$0.52
Coal Commodity Real Escalation	0.0%	0.5%	1.0%
Coal Transportation 2006 Price ($/MMBtu)	$0.55	$0.65	$0.75
Fuel Oil 2006 Price	$4.62	$5.44	$6.25
Financial Rates			
Inflation Rate	1.5%	2.5%	3.5%
Interest Rate	5.5%	6.5%	8.0%
Discount Rate		8.0%	
Resource Data			
Market Data:			
On-Peak Market Energy Availability	10.0%	40.0%	50.0%
On-Peak Market Price Adjustment	-10.0%	0.0%	10.0%
New Unit Data:			
Capital Cost Variance	-15.0%	0.0%	15.0%
Coal Unit Data:			
Transmission cost ($/kW-mo)	$3.17	$3.73	$4.29
SO2 Allowance Cost ($/ton)	$954	$1,122	$1,290
NOx Credit Costs ($/ton)	$1,267	$1,491	$1,715
CO2 Tax ($/ton)	$0	$0	$0
Particulate Costs ($/ton)	$0	$0	$0

Emission costs for the coal units were varied using a @risk function. The detailed assumptions for the above factors can be found in Appendix II.

The results of the risk analysis are summarized in Figure IV-1.

Figure IV-1
Probability Distributions for the Lower Evaluated Resource Portfolios



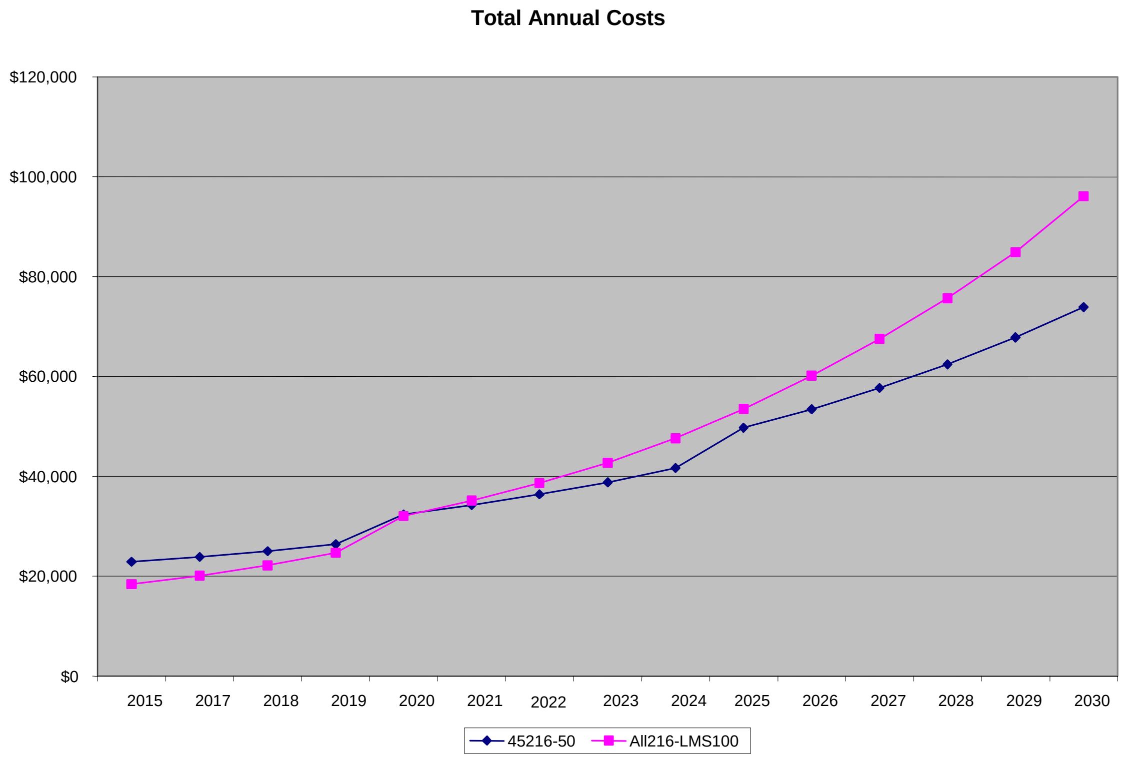
The results of the risk analysis indicate that the portfolios with approximately 100MW of coal energy provided through SLP Unit 4 and an additional 50MW result in the lower cost options. The scenario with the LMS100 case is shifted up due to the low probability that the capital cost will remain at the level of the initial units GE is bidding to obtain market acceptance. The portfolio with no SLP and 50MW of new coal capacity shows a broader distribution primarily due to the variance in capital and interest costs.

The four portfolios with the more narrow distribution indicate the following:

1. The SLP Unit 4 should be maintained in service.
2. An approximately 50MW amount of additional coal capacity provides value to RPU in offsetting the exposure to gas based energy.
3. Using the SLP Units 1-3 as regulatory reserves operated on natural gas or retiring them and replacing the capacity with a Twin Pac unit makes little difference since the energy expected to be generated by them is negligible.

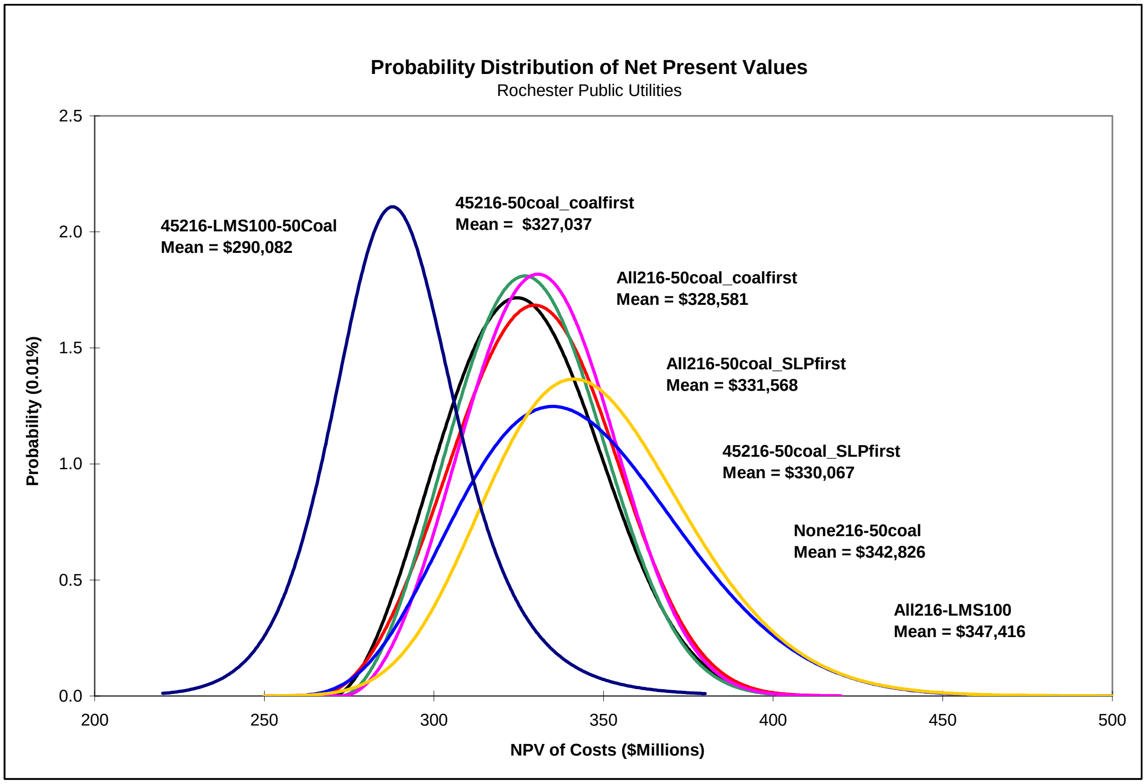
The above analysis has been performed on a net present value basis. A review of the total, demand related and energy related annual costs provide an insight to determine if the timing of the coal units might make a difference in the evaluation. Due to RPU's low load in the winter until about 2020, additional coal capacity would be difficult to fully utilize. To review this issue, the annual costs of the portfolios with the LMS100 and the 50MW coal purchase were compared. The annual total costs for the cases are shown in Figure IV-2. The total costs for the two cases cross about 2020, indicating that the energy from the coal unit does not begin to overcome its high capital cost until this point.

Figure IV-2
Total Annual Costs for the 50MW Coal Case and the LMS100 Case
($000)



A case was developed which reflected this type of sequencing for the gas and coal units. The net present value for the revised case was $288,674,000 or approximately 10 percent below the lowest evaluated case above. Application of the risk analysis to this case was performed and is included in Figure IV-3.

Figure IV-3
Probable Net Present Values
With Coal in 2020 Case



The risk analysis shown above indicates that combining the benefits of the LMS100 case with the 50MW coal case provides a lower risk case than the all gas cases. The major advantage is the delay of acquisition of the coal unit until its energy can be more fully utilized. This allows RPU to capture the early benefits of the LMS100 portfolio and the later benefits of the 50MW coal portfolios. Therefore, the sequencing of the unit additions should be considered with the gas unit in 2016 and the coal purchase in 2020.

Near Term Issues

The above analysis provides an insight to the course which RPU should pursue over the next ten years. The balance of loads and resources using the above 45216-LMS100-50Coal case is shown in Figure IV-4. As shown, the resource additions will still require that RPU acquire seasonal capacity to maintain its MAPP reserve requirements. The costs for these acquisitions have been included in the analysis. Figure IV-5 is an approximate energy dispatch curve to provide an indication of the sources of energy for the RPU in 2030.

Figure IV-4
RPU Balance of Loads and Resources
45216-LMS100-50Coal

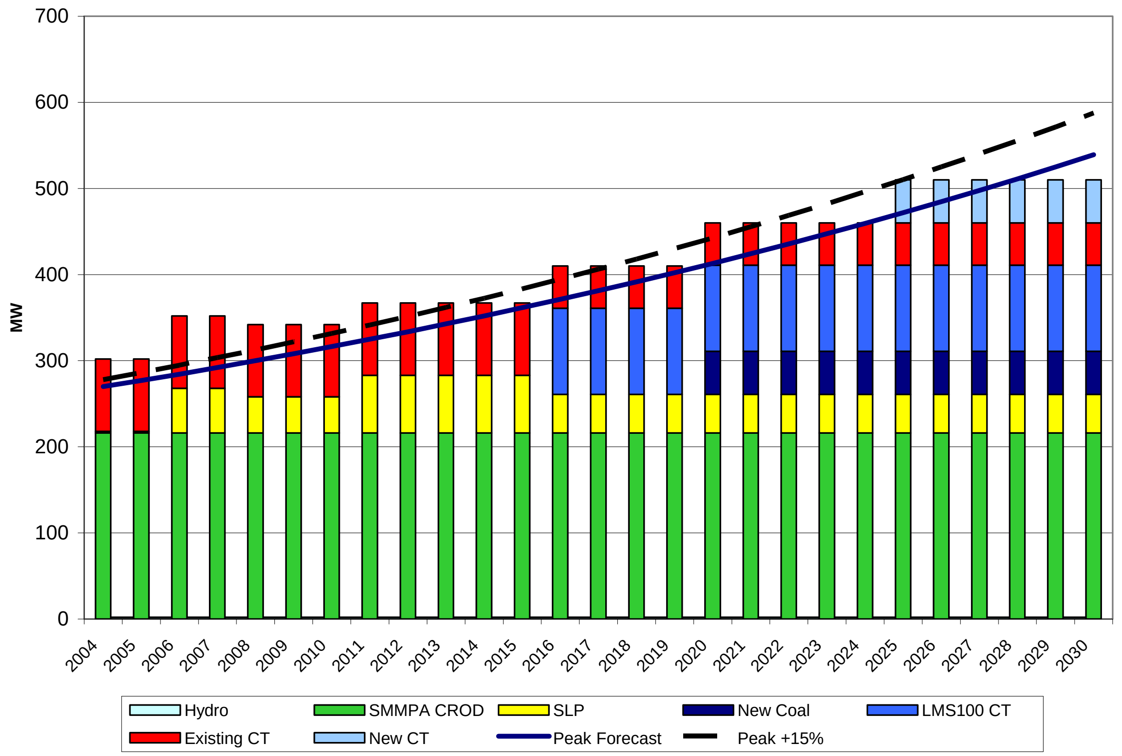
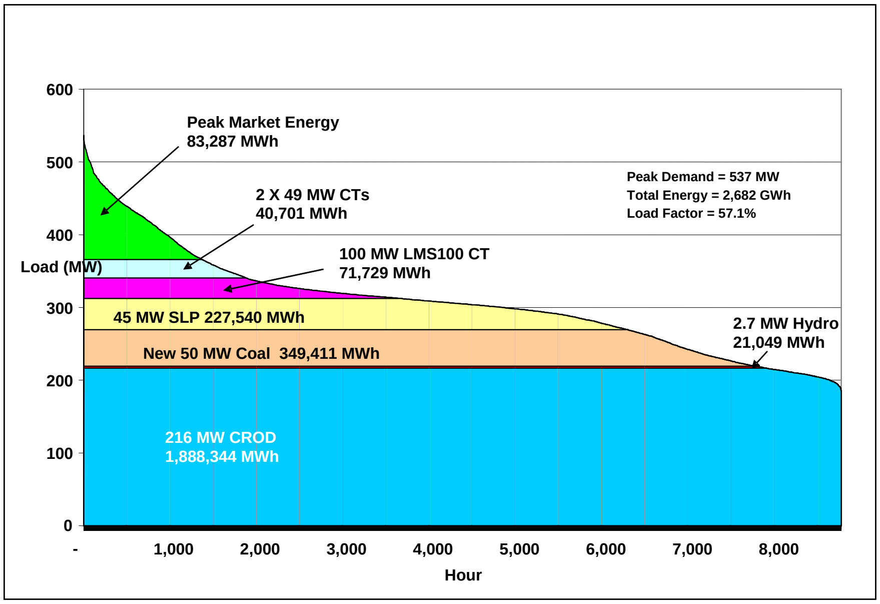


Figure IV-5
Approximate 2030 Energy Sources for RPU



Silver Lake Power Plant

The longer term portfolio options indicate that it is advantageous to continue the operation of the SLP, especially Unit 4 on coal. RPU should identify and implement strategies that will result in reduced air emissions and allow for continued operation on coal at an increased capacity factor. A boiler assessment should also be performed to determine if it would be beneficial to replace components which have had tubes plugged over the years to continue operation and delay maintenance investment.

Units 1-3 should be maintained in sufficient status to allow MAPP accreditation. Since these units are capable of being fired on natural gas available at the site, fuel switching may be an option to emission controls through the addition of flue gas based emission control devices. The cost of maintaining these units should be compared to replacing them with another resource closer to the 2016 time frame.

Maintaining the SLP plant also allows continued servicing of the Franklin Heating Station contract with excess steam and avoids any need to assess options for disposition of the contract with the Mayo Clinic.

Coal Unit Participation

There are several opportunities for RPU to participate in coal plants being developed in the regional. The units which are inviting participants are scheduled for in service dates of approximately 2010. Analysis of the coal portfolios indicates that RPU does not need coal capacity until after 2016 and more probably closer to 2020 based on the current forecast of load. Therefore, there is no urgency for RPU to identify a resource in which to participate.

RPU should maintain contact with regional utilities who may be considering a resource closer to the time when RPU could absorb the energy. It is expected that additional units will be required by others at a similar time that RPU is in need of coal energy.

Transmission Investment

RPU should aggressively pursue the upgrading of the transmission system. Certainly the firm delivery of the CROD energy should be regained since RPU is paying the SMMPA for firm all-requirements capacity and energy up to 216MW. This should be the number one priority of RPU in discussions with SMMPA.

RPU is participating in studies with other utilities on transmission projects which would improve the import capabilities into the service area. It is expected that the approach to improving the transmission system reliability into the RPU service area will be determined within the next 12 to 18 months. Currently, the state of the transmission system does not permit reliance on the market for firm purchases. Therefore, RPU will only be using the transmission system for non-firm energy deliveries above the CROD amount until increased firm transfer capability is available into RPU’s area. Sufficient generation capacity will need to exist within RPU’s service area to firm up the transmission system.

In discussions with RPU, it is uncertain what will happen to the CROD amount past 2030, which is the current termination date of the SMMPA contracts with its members. If the CROD energy is not available, then RPU will be in need of essentially 250MW of coal capacity. This amount of capacity requirement would support the construction of a unit within the RPU service area by RPU as the sole owner. With this amount of capacity inside the RPU service area, the import capability required of the transmission system would be reduced.

Due to the length of time it takes to construct transmission lines and complete the upgrade, it is recommended that RPU develop a parallel project to install similar Twin Pac units to maintain the required probable outage hour levels as would be maintained with the transmission upgrade. Should the upgrade be delayed, the generating units could be installed within RPU's service area and used for transmission reliability service until the upgrade was completed.

Summary

Overall, RPU is in relatively good condition to meet its load requirements for several years without any additions to its resource mix. Challenges to RPU in the area of transmission reliability and understanding what future market operation impacts will bring are typical of the environment in which utilities operate today and will be a primary focus of RPU. Plant related issues will include the investment necessary to bring the SLP into compliance with environmental regulations currently taking affect.

Based on the analysis performed for RPU in this effort, Burns & McDonnell is of the opinion that RPU should:

Over the next few months:

1. RPU is not in need of additional coal capacity with the current CROD level and load forecast until approximately 2020. Therefore, participation in any coal plant currently being developed does not appear to be advantageous.

2. Pursue firming up the transmission system to allow firm delivery of the CROD amount of 216MW.

3. Consider taking options on approximately 100 acres of land within the RPU service territory near a high pressure gas line and transmission facilities under RPU control for installation of future combustion turbine capacity.

4. Develop a parallel path project to accelerate installation of combustion turbine capacity required in the long term plan to maintain system reliability should the selected transmission upgrade project be delayed.

5. Develop the upgrade plan and timing for SLP Units 1-4 for the addition of emission controls and other life extension modifications.

Between 2005 and 2015:

1. Complete the transmission upgrade or the installation of additional combustion turbines.

2. If the transmission upgrade is completed, compare the market conditions at the time to the installation of additional generation resources within the service territory.

3. Review the then current generation technology, fuel options and RPU needs against the long range plan developed herein to determine if new technologies or reduced RPU needs have usurped the analysis and recommendations associated with current options.

4. Complete the modifications to the SLP Unit 4. Initiate the emission controls to be applied to Units 1-3 in light of their expected operation.

5. Around 2010, depending on the status of the RPU system needs, the regional market, and other technology considerations for resource options, RPU should consider taking an option on approximately 1500 acres to support the development of a coal-fired generation plant within the RPU service territory. The site should have access to rail, electric transmission and water infrastructure to support several hundred megawatts of generation.

6. Around 2012, assuming that new generation is required in accordance with the long range plan and that generation has not been installed in connection with the transmission issue, begin the process for installation of approximately 50 to 100MW of natural gas-fired generation for an in service date of 2016. The generation should be low capital cost with as low an operating cost as is consistent with expected operating capacity factors.

Between 2015 and 2030:

1. Install generation as necessary and prudent using the long range plan prepared above as a guide and comparing the assumptions used herein to the existing market conditions. The generation additions should follow the in service schedule identified in portfolio 45216-LMS100-50Coal.

2. If development of a local coal unit appears likely, purchase the necessary land and begin the development process around 2015 for an in service date of 2020.

*****

Part V

Demand Side Management and Renewable Options

Rochester Public Utilities (RPU) is active in promoting demand side programs to its customers to help conserve electric energy, and reduce demand in its service territory. Numerous programs are offered to assist customers in reducing their electrical requirements. The development of the financial plan for RPU requires the assessment of the impacts that customers are making, and could make, in the reduction of future electrical requirements, and delay the need for additional capacity.

Current DSM Efforts

Utilities in Minnesota are required to invest a portion of the revenues into DSM programs. For RPU, this amounts to approximately $1,300,000 per year. RPU has created a department to manage the budget associated with DSM programs. The department is staffed with individuals who work with customers to promote the various DSM programs in place, provide energy audit services, and look for new programs to implement.

RPU is working with the cities of Owatonna and Austin, Minnesota on DSM offerings. These utilities have formed the Triad, which allows the cities to share personnel, study costs, and other assets in order to reduce the overheads and program costs associated with the DSM programs.

The programs offered by RPU include:

- Conserve and $ave – a program to promote the use of Energy Star appliances and other high-efficiency equipment in place of lower efficiency options. The program is open to residential, commercial, and industrial customers. Rebates are provided for a variety of appliances, equipment, and lighting options.
- Partners Load Management – a program to allow RPU to control central air conditioner compressors and electric water heaters during times of high demand and reduce the load on the system.
- Energy Audits – these are provided to customers upon request.

The cumulative estimated reductions due to these programs as of January 1, 2004 are:

- Energy savings of 7,860 MWh.
- Demand savings of 5,960 kW.

Using an average of $600/kW of installed capacity and $55 per MWh as an avoided energy cost, the programs have provided approximately $3,500,000 of reduced investment cost and $432,000 of annual energy savings.

Study Approach

A variety of tasks were undertaken to develop the expected impacts that current and potential DSM programs could provide in reducing the RPU need for additional power supply resources. These tasks included an end use survey of RPU's customers, a benefit cost analysis of RPU programs, and an estimation of the electric energy and demand reduction potential for RPU's customer base.

In addition to these tasks, public involvement was solicited to discuss options and considerations from the ratepayer's perspective. RPU developed a task force made up of a representative from the various rate classes and other involved citizens served by RPU.

End Use Survey

RPU retained Morgan Marketing Partners of Madison, Wisconsin to perform an end use survey of their residential and commercial customers. Large industrial customers were not surveyed due to the unique nature of their loads. These customers are actively involved in reducing the consumption of their processes. Also, RPU devotes a staff person to work with these individuals to help them reduce their consumption.

The survey questionnaire was developed and mailed to 1,497 residential, and 2,193 commercial and industrial customers. These responses provided a statistically significant result and were considered to be acceptable for use in analyzing the appliance inventory in the RPU service territory. The questionnaires and a summary of the results of the survey are included in Appendix IV.

Benefit Cost Analysis

In addition to the end use survey, RPU needed to perform a benefit cost analysis of the various DSM offerings applicable to RPU. RPU retained the Center for Energy and the Environment (CEE) to perform this analysis. The CEE is a not-for-profit corporation in Minnesota that is funded by utilities to assist with DSM program analysis. The CEE is very experienced in performing analyses of DSM programs in accordance with the requirements of the Minnesota state regulatory bodies for utilities. The CEE works with the Triad and has the information on the various programs offered, avoided costs, and other information necessary to perform the benefit cost analysis.

The analysis of avoided costs for RPU is different from the other members of the Triad in that the other Triad members are full service customers of SMMPA, while RPU takes a portion of its requirements from SMMPA and a portion from other resources. The RPU avoided costs vary between seasons based on whether the demand is being provided solely by SMMPA or from both SMMPA and RPU resources.

The analysis looked at the benefit and costs using the four typical tests for DSM programs. These included:

- Revenue requirements – this test looks at the benefit cost from the RPU perspective;

- Rate impact – this test looks at the benefit cost from the non-participant perspective;
- Participant – this test looks at the benefit cost from the participant's perspective;
- Societal – this test looks at the benefit cost from society's perspective.

A variety of conservation programs were selected for the residential and commercial sectors. The initial assessment of the programs identified that the avoided costs for RPU needed to be revised when compared to the other Triad members. RPU has a different cost structure due to the limitation of the demand and energy received from the SMMPA. This means that the avoided demand charge is different through the year. Also, the method of meeting demand in the summer is through combustion turbine capacity, which is lower cost than that of the SMMPA demand. This information was updated in the CEE model for RPU.

The program costs for each of the programs were provided by RPU to CEE for use in the assessment. These costs included staff, rebates and incentives, advertising, and other costs associated with maintaining the various programs. The model used by CEE processed the information with regard to the specific test being developed. The appliances and programs selected for review were based on the experience of CEE in performing these tests for a variety of utilities in Minnesota. The results are shown on Table V-1.

Table V-1
Summary of Benefit Cost Analysis Results

Cost Benefit Analysis for Rochester Public Utilities				
2004 Results		**B/C Ratio**		
Program Name	**Revenue Requirements**	**Rate Impact Measure**	**Participant**	**Societal**
RESIDENTIAL				
Electric VSD/ECM Motors	**5.53**	**1.09**	**2.21**	**1.83**
Clothes Washer (Elec WH)	**4.14**	**1.28**	**0.89**	**0.96**
13 SEER Central A/C	**4.10**	**2.01**	**1.13**	**1.95**
14 SEER Central A/C	**3.53**	**1.86**	**1.07**	**1.73**
Ground Source Heat Pumps (3 ton unit example)	**2.31**	**1.27**	**0.98**	**1.08**
Room A/C	**1.70**	**1.14**	**1.89**	**1.52**
Dish Washer (Elec WH)	**1.47**	**0.80**	**1.60**	**0.98**
Refrigerator	0.93	0.53	2.50	0.83
Dish Washer (Gas WH)	0.64	0.47	0.98	0.43
CFL's	0.60	0.30	19.48	0.59
Clothes Washer (Gas WH)	0.42	0.35	0.24	0.10
Load Management	0.00	0.00	38,950.33	0.00
COMMERCIAL				
VSD (200 hp)	**40.34**	**1.61**	**5.21**	**6.38**
Premium Efficiency AC 3-Phase Motor (200 hp)	**4.02**	**1.10**	**7.00**	**3.55**
ECPM (1.5 hp)	**2.99**	**0.94**	**8.90**	**2.33**
VSD (3 hp)	**2.92**	**1.06**	**1.12**	**0.96**
Air-Conditioners EER=11.0 (7.5 tons)	0.83	0.54	2.55	0.69
Lighting Retrofit - Exit Sign (20W Incan. to LED)	0.66	0.45	4.29	0.57
Lighting Retrofit (F40T12 4 lamp to F32T8 LP 4 lamp)	0.57	0.40	6.95	0.53
Premium Efficiency AC 3-Phase Motor (1.5 hp)	0.20	0.18	3.36	0.19
GSHP (5 ton unit example)	0.13	0.12	2.20	0.12
ECPM (0.1 hp)	0.11	0.10	2.06	0.11

The results indicate that most of the residential and all of the commercial programs evaluated are beneficial from the Participant perspective. However, only about half of the programs are beneficial from the other three perspectives. All of the appliances are currently included in the Triad Conserve and $ave program. The load management program does not look beneficial at this point due to the excess capacity and the cool summer weather that has depressed demand during the summer months. With this combination, RPU does not need to cycle air conditioners or water heaters to reduce demand. The Participants see this as a significant benefit since they are still provided a credit from RPU for having the switch installed.

CEE has recommended that the overhead costs and incentives for the Triad should be reviewed to improve the number of programs with a benefit cost ratio greater than one.

The Triad has developed a report on the modifications to the demand side management programs currently in effect and additional programs to be undertaken in their report “Next Level”. This report identifies numerous adjustments to the programs in the areas of incentives, education, and expected participation levels. A copy of the report is included in Appendix IV.

Task Force

As part of the assessment of DSM programs and opportunities, RPU created a Task Force made up of representatives from residential, commercial, and industrial RPU rate classes. In addition, representatives from local environmental groups were included. There were 12 members in total. The group met three times to discuss the issues associated with DSM programs. The first meeting was held to educate the group on the current supply and demand side issues and opportunities facing RPU. The second meeting provided information about the end use survey and the benefit cost study being prepared for RPU. The third meeting was to provide the estimated impacts of various DSM activities and to collect feedback and recommendations from the group on how RPU should proceed.

In general, the Task Force had the following recommendations:

1. Programs involving rebates should be simple and provide immediate benefit to the customer.
2. Conservation programs and other efficiency enhancing programs require continual education of the customers.
3. Revising rate structures to support demand side and renewable energy efforts should be pursued.
4. Implementing time-of-use rates should be pursued.

The summary of recommendations from the group is included in Appendix IV.

Review of Conservation Potential

The potential for electrical energy and demand reductions on the RPU system were estimated using the end use survey data and typical savings information from a variety of sources used to estimate the reductions by appliance or facility change. The end use survey information provided an estimate of the number of appliances on the system that were available for enhanced efficiencies. The appliance usage was estimated to determine the amount of energy savings which could result from a conversion. The expected usage patterns through the day were approximated in order to estimate total demand reduction. Assumptions for energy reductions were obtained from Energy Star calculators that are available from the Department of Energy, the assumptions in the Benefit Cost study and other sources.

Residential Potential

The residential customers of RPU are typical of households across the US. The use of central air conditioning is widespread. The availability of natural gas has led to a high utilization of gas-fired heating systems and water heaters. Therefore, the maximum electrical demand is in the summer season. (See Figure II-6 in Part II for the RPU annual load shape.)

The number of central AC units older than 5 years provided an estimate of the number of units that had a SEER of below 8. Units installed within five years have had a SEER of at least 10. From the survey, an estimated 20,000 central AC units have a SEER of 8 or less. The benefit cost analysis identified that conversion of this appliance to a SEER of 13 and14 was beneficial from all perspectives. In addition to the AC units, conversion of the blower motor in the air handler was also beneficial from all perspectives. These two categories represent the largest efficiency enhancement benefits available from the residential sector.

Another category of appliances with a high potential for savings are the washer and dryers. Energy Star washers reduce the water necessary to clean clothes and also remove more water than traditional washers to reduce the drying time necessary. New efficient dryers have moisture sensors that determine when the clothes are dry. From the benefit cost study, it is seen that the current level of benefits from the Participant's perspective do not make replacement of units with an Energy Star rated unit attractive. This is primarily due to the high cost of the replacement appliances.

Other kitchen appliances provide minimal benefit from all perspectives. Compact fluorescent lights (CFL) provide significant benefits from the Participant's perspective. From the end use survey, it appears that over half of the homes in RPU's service territory have some amount of CFLs installed. The residential CFL replacements provide primarily energy reductions with minimal impact on the RPU peak.

Table V- 2 provides a summary of the maximum potential reductions for the residential sector estimated from a variety of efficiency improvements for appliance conversions or for change out of central AC units to a SEER 13. The number and efficiency of existing appliances was determined from the end use survey.

An area of interest to some utilities is the conversion of electric appliances to natural gas, where gas is available. A list of appliances that could potentially be converted and the expected electrical reductions is also included in Table V- 2.

Table V-2
Estimated Maximum Potential Reductions
Residential RPU Customers

Residential			**Estimated Savings**		
			Energy		**Demand**
Energy Star Conversions	**Quantity**	**Unit**	**Each (kWh)**	**Total (MWh)**	**(MW)**
Central Air more than 5 years old	20,484	Customers	346	7,091	4.7
Room Air more than 5 years old	2,618	each	58	151	0.1
Refrigerator more than 5 years old	13,176	each	95	1,252	0.2
Freezer more than 5 years old	1,231	each	80	98	0.0
No Compact FL	15,214	Customers	124	1,887	0.0
Washing Machine	38,705	Customers	361	13,973	2.4
Dishwasher-heated drying (elec DHW)	1,175	Customers	103	121	0.0
Dishwasher-heated drying (gas DHW)	8,617	Customers	45	388	0.0
				24,960	7.4

			Total Use		
Other Options			**Each (kWh)**	**Total (MWh)**	**Demand (MW)**
Electric heat-Main	788	Customers	43,174	34,021	n/a
Dryer	30,342	Customers	995	30,190	5.2
Spa/Hot tub	585	Customers	1,680	983	n/a
Water Heater	4,375	Customers	4,811	21,048	1.5
Range/Oven	30,704	Customers	256	7,860	n/a
				94,103	

Commercial Potential

The commercial sector of RPU reviewed in the survey is made up primarily of small commercial office buildings, shopping malls, restaurants, and other typical buildings. Estimates of reductions for the commercial sector required comparing end used information from the survey with industry data, forecast sales by class, correlation with SMMPA data in its Integrated Resource Plan and other factors.

References and calculation tools used in the commercial assessment include:

- ***End-use Survey of RPU Commercial Customers:*** A survey sent to 2,145 of RPU's commercial customers. Used to determine quantities of customers and appliances.

- ***eQUEST:*** *A* computer simulation program that is a full implementation of the widely recognized DOE 2.2 calculation engine. It can perform hourly calculations for an entire year and incorporates local weather data.

- ***U.S. Department of Energy – 2004 Buildings Energy Data Book:*** This reference includes over 100 pages of data tables dealing directly with buildings and their energy use.

- ***Energy Star Homepage:*** Web site with a variety of reference material and calculation tools for various technologies. Estimates that involved use of these calculation tools includes room air conditioners, freezers, washing machines, dishwashers, computers, printers, and copiers.

- ***SMMPA Integrated Resource Plan 2003-2018:*** In particular Table VII-8, *"SMMPA Sales Profile"*, which has an end-use breakdown of electricity use for commercial customers. The metric used is the Energy Use Indices (EUI) which has the units of kWh/yr/sq ft.

There are a number of assumptions included in the DSM measure energy reduction estimates for commercial customers that involve usage estimates per square foot of commercial building space. A review of the 2,145 survey population of customers used in the survey indicated the following:

- 61.5% consisted of small commercial properties totaling 5,000 sq. ft. or less,
- 28.8% were 5,001 – 25,000 sq. ft.,
- 9.1% were 25,001 – 250,000 sq. ft. and
- 0.6% were 250,000 or more sq. ft.

Due to the effort in the existing DSM programs on the large customers, the focus of the analysis in this study was on the commercial space of less than 25,000 square feet. A review of information included in the SMMPA IRP provided that RPU commercial customers account for 50 percent of the SMMPA commercial customers' energy use. Based on other information about the square feet of commercial office space in the member cities' service areas, it was determined that RPU's commercial customers account for 50 percent of the SMMPA commercial customers' floor space (i.e., 50 percent of 67,210,000 sq. ft. or 33,605,000 sq. ft.).

The above area of commercial space was used to derive an estimated energy usage. One reference for determining the energy usage was data from the US Department of Energy – 2004 Building Energy Data book. To determine the potential reduction for estimating DSM impacts, it was assumed that the DSM measures will have 100 percent penetration. In other words all customers that are candidates for a given DSM measure will implement the measure.

The approach used to determine the potential energy savings for RPU's commercial customers included three basic steps. These are:

1. Identify the appliances and energy using systems that account for the majority of overall electric consumption.

2. Use the end-use survey to determine the number of customers, or quantity of energy using devices identified in step 1. In some cases the DOE – 2004 Buildings Energy Data book was used as a reference for average typical commercial customers.

3. Use engineering calculations to determine the energy savings for the devices and quantities identified in steps 1 and 2 respectively.

The results of the analysis are summarized in Table V-3.

Table V-3
Estimated Maximum Potential Reductions
Commercial RPU Customers

Commercial			**Estimated Savings**		
			Energy		**Demand**
Efficiency conversions	**Quantity**	**Unit**	**Each (kWh)**	**Total (MWh)**	**(MW)**
Central Air more than 7 years old	936	Customers	3,948	3,695	5.3
Room Air more than 7 years old	226	each	121	27	0.1
Refrigerator more than 7 years old	2,214	each	143	315	0.2
Freezer more than 7 years old	858	each	120	103	0.0
No Compact FL	1,386	Customers	4,015	5,565	2.0
Washing Machine	515	Customers	722	372	0.1
Dishwasher-heated drying	67	Customers	78	5	0.0
Non electronic ballast flourescent	1,639	Customers	9,489	15,552	8.8
VSD on 3 HP AC unit fans	3,595	each	5,489	19,734	0.3
Computers	18,190	each	201	3,656	1.2
Printers	7,096	each	180	1,277	0.4
Copiers	5,103	each	324	1,653	0.5
				51,957	18.8

Other Options			**Total Use**		
Energy Using System/Device	**Quantity**	**Unit**	**Each (kWh)**	**Total (MWh)**	**Demand (MW)**
Electric heat-Main	118	Customers	86,348	10,189	n/a
Dryer	498	Customers	1,493	743	0.4
Range/Oven	44	Customers	384	17	n/a
Water Heater	568	Customers	9,622	5,465	2.4
				16,415	

Information for both the commercial and residential impacts determined above are included in Appendix IV.

Load Shape Modification Programs

Utilities have been controlling demand on the system since the late 1970's through the use of load management programs, interruptible rates and other programs that entice the customer to allow the utility to remove a portion of their load during high usage times. The economics of these programs are dependent on the cost of the marginal capacity on the system. As the utility moves between deficit and excess capacity conditions, the value of the program changes.

Another type of program which is gaining prominence is called a Demand Response Program. These programs are trying to bring the consumption side of the industry into the market to allow a demand response feedback to the hourly pricing. As wholesale markets move to day ahead pricing with load bidding into the market, these programs are becoming more useful.

The current wholesale market is discounting the value of capacity. Although the forward market (in the post 2010 time frame) is seeing the need for additional base load facilities which have high fixed cost, the current market is not pricing capacity above that for a combustion turbine, if that. However, the price for energy is increasing as more of the marginal energy produced is from natural gas-fired units. It is expected that this market will continue in this manner for several years at least. No significant structural change to this pricing on the wholesale markets operated by PJM and MISO is expected until base load units are added to the system beyond 2010.

Load Management

RPU has approximately 8,800 customers with load management switches installed. The evaluation of load management programs in the Benefit Cost Study revealed that there was no benefit from any perspective except for the Participant. This is due to the current capacity situation in RPU and the mild summer experienced in 2004. With the expected return of capacity from the Silver Lake Plant over the next several years, RPU has sufficient capacity to meet its obligations. Therefore, there is no cost avoided for the reduction in peak.

The primary benefit from the load management program will be from the opportunity to market excess capacity. Also, having the load management system provides some increased system security during times when the transmission capacity into RPU is constrained and load needs to be curtailed in the RPU area.

Another aspect of the load management program is that the appliances controlled are primarily central AC units and electric water heaters. Over the next several years, replacement units will be installed for the approximately 20,000 central air conditioning units with SEER ratings below 8. These units will be replaced with AC units with a SEER rating of 13 or better. These newer units have a lower demand than the older units. Also, since many of the units were installed oversized, smaller units may be used for the replacements. These two factors lead to the conclusion that the amount of reduction per point for the load management system will decline over the next five years. It is estimated that this reduction will be approximately .1 to .2 kW per central AC unit. Change out of electric water heaters to gas units would also reduce the amount of load under control.

Demand Response Programs

Demand response programs are gaining in popularity with utilities as markets move to the day ahead pricing structure used by the PJM, the MISO Day 2 market to start in March, 2005 and as promoted by the FERC in the Standard Market Design. These programs have a variety of definitions, but in general, entail using time-of-use metering or notification devices and rates to encourage consumers to reduce electric energy consumption during periods of high energy pricing. As the electric wholesale market moves to the day ahead of energy pricing, the knowledge of tomorrow's costs are more readily determined. These then can be shared with the customers to allow them to control their consumption during the periods when the pricing is above their threshold.

There are two broad categories of demand response programs. The first is applicable to markets where the load is bid into the market, such as will exist in the MISO area when its Day 2 operations are implemented. This conversion is expected to occur on or after March 1, 2005. In this program, qualifying customers are paid to reduce their demand by the level contracted with the utility. Verification of the amount of reduction is required. A set strike price for the capacity is often provided, such that there is no activity of the control unless the price exceeds a set level. In these programs, the customer is actually paid by the utility to reduce consumption at an agreed to rate. Qualifying customers are typically those that can reduce at least 100kW or more.

The other type of program incorporates the residential and small commercial customers. In this type of program, the customer is sent information on the time-of-use cost of the electricity. The customer then makes the choice on whether to shift usage away from the higher priced times to lower priced periods. This type of program simply results in the customer realizing a reduction in their bill due to avoiding the higher cost periods.

The first type of program could be used by RPU to release capacity for sale in the day ahead of the MISO market. Therefore, although the demand reduction has no specific value to RPU from an avoided capacity purchase, there may be value from the opportunity cost of potential sales and positioning for future years when capacity may be tighter. The development of the MISO Day 2 market on or after March 1, 2005 will need to be monitored to determine if this type of program would be of benefit and the revenues to the qualifying participants significant enough to gain a critical mass for participation.

The use of a demand response program by RPU for the residential and small commercial customers would require creating time-of-use pricing information for transmission to the customers who wish to participate. This pricing could be based on the MISO Day 2 market, which will provide the day ahead hourly pricing for the next day. Adjustments to this price for RPU costs would be made and forwarded to the participating customers.

Although time-of-use programs have been offered for several years, recent technology and communication changes have allowed the programs to be lower cost to implement. Savings resulting from the programs have been discussed in recent markets, such as California's during its crisis, and found to be significant when the price is above the customer's threshold. Although claims of 2kW per consumer in the program have been made by companies promoting the systems to support the programs, RPU would have to perform a pilot to determine what the level of pricing would need to be to influence the consumers in RPU's service territory to make any meaningful adjustment to their usage patterns.

Finally, it is important to note that from a customer's perspective, demand response strategies are effective only for those that are willing to change their energy usage habits. Contrarily, demand response strategies will not benefit those that are unwilling to change their usage habits. Therefore, selling DSM must be promoted as a conservation strategy and targeted to those that are willing to change their energy usage habits.

RPU DSM Program

The estimation of actual DSM impacts from various programs that have been or could be implemented by RPU allows a determination of the potential influence on the need for supply side resources. Since the DSM programs require acceptance by RPU customers, one unknown in the equation is the amount of participants in any program. The companion uncertainty to the level of participation is the amount per year who will participate.

In addition, natural replacement of appliances over time tends to reduce the average consumption since the replacement models have improved efficiencies. For instance, central AC unit efficiencies were increased to a minimum SEER of 10 in 1992. New standards are set to take affect in 2006 that increase the minimum SEER to 13. With this natural increase in efficiencies, the affect on RPU's load could be a reduction of approximately 30 percent of the energy over the approximately 20,000 central AC units that are older than five years. Major reductions would come from units that were installed prior to 1992. Similar improvements would come about from natural replacements of other appliances such as refrigerators and dishwashers.

In addition to the traditional impacts from DSM programs, RPU is also developing a cogeneration system with the Mayo Clinic's Franklin Heating Plant. This cogeneration effort will remove approximately 5MW (electric) from the system in 2008 and grows to approximately 15MW (electric) in 2015. This demand and its associated energy are removed from the electric system.

Using the information provided in Table V-2 and V-3 for the efficiency improvements and the benefit cost analysis Table V-1, estimates of reduction were developed. The resultant expected levels of reduction per year were identified to allow a determination of the impact on the load forecast as adjusted for DSM programs. A summary of the projections are shown in Table V-4. These projections include efforts to achieve reductions that are influenced by RPU and naturally occurring efficiency improvements in the existing appliance inventory. It is assumed that the naturally occurring efficiency savings would be achieved by 2015. Beyond 2015, the ongoing DSM activities of RPU would be the source of additional savings.

Due to the efficiency standards taking affect in 2006 and the need to develop the educational and incentive programs to be implemented to achieve savings, it was assumed that no savings would accrue in 2005 beyond the existing DSM program impacts. Starting in 2006, one third of the savings would accrue each year until the full savings of approximately 9,000 MWh annually would be achieved. It is estimated that these efficiency improvements would be completed after ten years and the savings from these areas would then remain constant after 2015. For purposes of estimating savings, one half of the Table V-4 projections are to be included in the RPU DSM future savings, while the remainder is considered to be an aggressive DSM alternative.

Table V-4
Estimated Additional DSM and Efficiency Impacts
To RPU Energy Forecast
(MWh)

Program	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential											
Central AC	0	236	475	709	709	709	709	709	709	709	709
Blower Motors	0	692	1,391	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076
CFLs	0	63	127	190	190	190	190	190	190	190	190
Refrigerators	0	42	84	125	125	125	125	125	125	125	125
Gas switched appliances	0	83	168	250	250	250	250	250	250	250	250
Commercial											
Central Air more than 7 years old	0	123	248	370	370	370	370	370	370	370	370
No Compact FL	0	185	373	556	556	556	556	556	556	556	556
Non electronic ballast flourescent	0	517	1,040	1,552	1,552	1,552	1,552	1,552	1,552	1,552	1,552
VSD on 3 HP AC unit fans	0	658	1,322	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973
Computers	0	122	245	365	365	365	365	365	365	365	365
Printers	0	43	86	128	128	128	128	128	128	128	128
Copiers	0	55	111	165	165	165	165	165	165	165	165
Gas switched appliances	0	250	503	750	750	750	750	750	750	750	750
Total	0	3,069	6,170	9,208	9,208	9,208	9,208	9,208	9,208	9,208	9,208
Cumulative Total	0	3,069	9,239	18,447	27,656	36,864	46,073	55,281	64,489	73,698	82,906

The estimated demand and energy impacts, including the Mayo cogeneration project, are shown in Table V-5. The Original Energy Forecast was the energy projection used for Phase I. The Existing DSM Impacts include the existing RPU DSM program estimated savings. The Future DSM impacts are one half of the saving shown in Table V-4. The Revised Energy Forecast is determined by subtracting the Future and Existing DSM Impacts from the Original Energy Forecast. The Aggressive Energy Forecast includes the remainder of the savings estimated in Table V-4.

Table V-5
Estimated DSM and Efficiency Improvement Impacts
Demand (MW) and Energy (MWh)

Year	Annual Peak	Demand Adjustments	Adjusted annual Peak	Original Energy Forecast	Future DSM Impacts	Existing DSM Impacts	Revised Energy Forecast	Aggressive Energy Forecast
2005	277	16.6	260	1,377,767	0	8,590	1,369,177	1,369,177
2006	284	21.8	262	1,414,967	1,535	56,310	1,357,122	1,355,588
2007	292	23.1	269	1,453,171	4,620	64,550	1,384,001	1,379,382
2008	300	25.1	275	1,495,732	9,224	72,650	1,413,858	1,404,635
2009	308	25.3	283	1,532,702	13,828	80,650	1,438,224	1,424,396
2010	316	26.9	289	1,574,085	18,432	88,500	1,467,153	1,448,721
2011	325	29.2	296	1,616,585	23,036	96,210	1,497,339	1,474,302
2012	334	31.8	302	1,663,932	27,641	103,790	1,532,501	1,504,861
2013	343	34.9	308	1,705,059	32,245	111,150	1,561,664	1,529,420
2014	352	38.4	314	1,751,096	36,849	118,450	1,595,797	1,558,948
2015	362	42.8	319	1,798,375	41,453	125,770	1,631,152	1,589,699

Renewable Energy Options

The state of Minnesota has implemented requirements for renewable energy under Minnesota Statute 2003 Chapter 216B. Retail electric utilities must offer customers an opportunity to purchase, at cost, renewable energy beginning July 1, 2002. RPU is offering customers the opportunity to purchase this energy under its Wind Power program in association with SMMPA.

Utilities are required to generate or procure renewable energy sufficient to ensure that by 2005, 1 percent of total retail sales are from renewable energy. This “Renewable Energy Objective” (REO) ramps up by 1 percent each year until 2015 when a total of 10 percent of retail sales must be from renewable energy. The REO also requires that, of the renewable generation required, in 2005 at least 0.5 percent be from biomass energy technology, increasing to 1.0 percent by 2010.

The integration of this energy into RPU’s resource mix will require adjustments to the dispatch determined in the traditional resource portfolios identified above.

There are several renewable energy options in commercial use. The most often considered include solar, wind, and biomass. In addition, the REO allows the use of electricity generated using municipal solid waste and existing hydro-electric generation to count towards the renewable requirement. The application of these options requires an assessment of their energy production capabilities, resultant power costs and the benefit to the RPU requirements. Following is a discussion of these alternatives.

Solar

The use of photovoltaic solar panels for electricity production is increasing annually. The largest increases are in those locations with high power costs coupled with net metering regulations, such as California, and remote from the grid applications. The Department of Energy has initiated a program to promote the use of solar through programs such as the Million Solar Roofs program. Probably the most advanced utility application of solar is in California and the leading utility is the Sacramento Municipal Utility District (SMUD) in Sacramento. For an idea of the size of an installation, a 2 MW array takes about 8100 square meters (about 2 acres). Costs of these installations are about $5000 per kW. Rooftop arrays provided under the SMUD program cost about $3500/kW and, on average for each kW produced, about 1800kWh of energy per year.

The output of the array is obviously dependent on the sun and the location of the array. In order to obtain specific information about the solar output in the RPU area, RPU assisted in the installation of an array on a residence in Rochester in the spring of 2004. The unit is a fixed plate array rated at 2.6kW and was installed in April 2004 at a residential customer. Information from the site is summarized in Table V-6. The cost of this array was $17,951 or approximately $6,900 per kW.

Table V-6
Solar Information from a 2.6kW Fixed Plate Array
Rochester, MN

Month	No. Days	Produced	Cap Factor	Max Output
April	17	156.047	0.1476711	2.096
May	31	276.071	0.14326763	2.216
June	30	300.097	0.16092718	2.084
July	31	310.481	0.16112478	2.108
August	31	248.101	0.12875254	2.04
September	30	194.925	0.10452864	1.3
October	31	91.791	0.04763514	1.88
November	7	37.111	0.08528912	
Yr. 2004	208	1614.624	0.1248812	

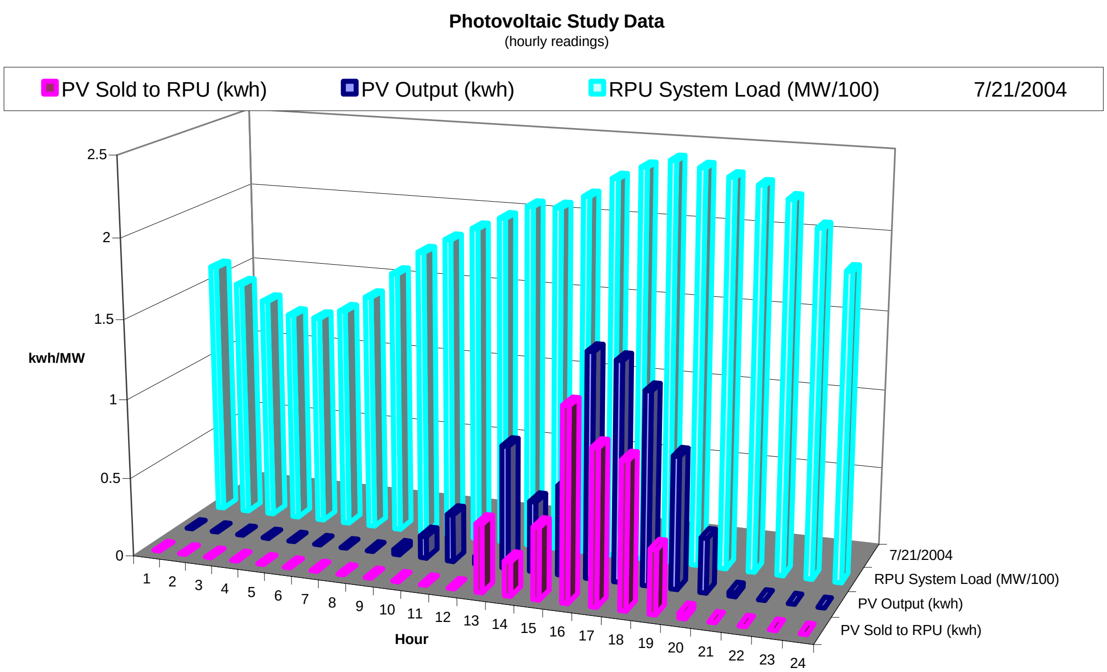
Legend:
Produced: The number of kWh produced by the PV array.
Capacity Factor: Based on a 2.59kW array rating
Max Output: The maximum kWh per hour measured

Note: Information from RPU's installation. Installed April, 2004.

The information from RPU is based on a flat plate array installed on a local residence. The output for the array was combined with the RPU system load for the same time period. The results are shown in Figures V-1 and V-2. Additional information was obtained for solar installations in the Minneapolis area.[1] A copy of the analysis is included in Appendix IV.

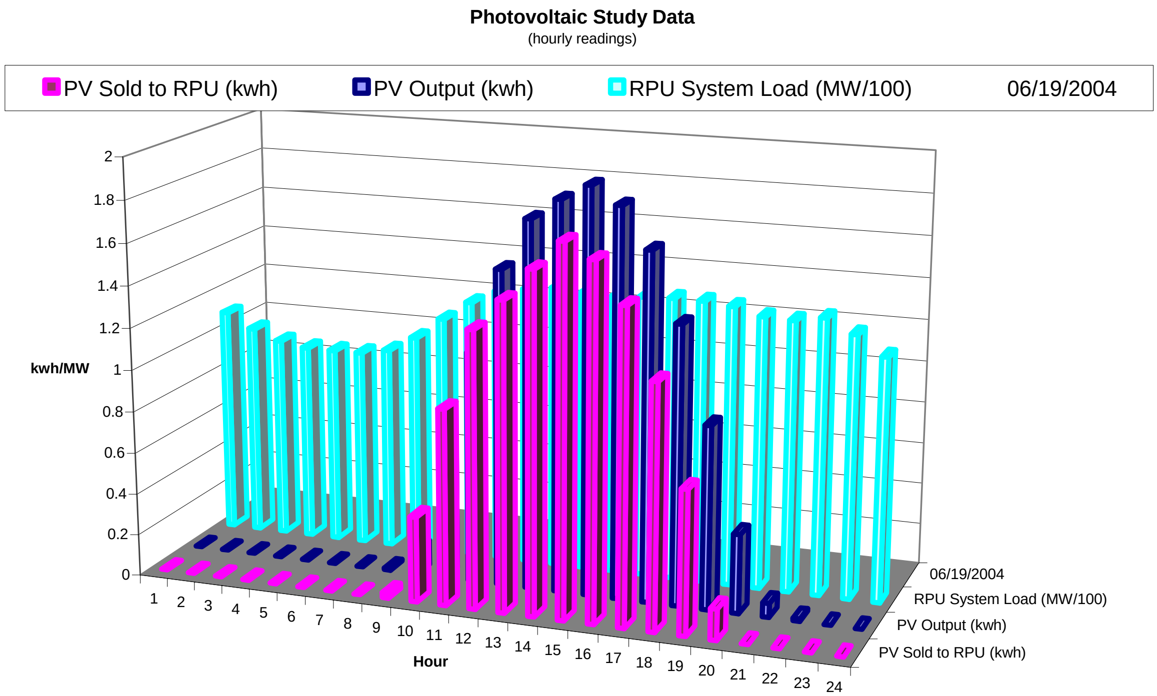
As shown in Figure V-1, the solar output drops to zero before the RPU system load declines significantly. This would require that RPU have sufficient generation available to meet its system needs in addition to having the solar output available. Also, the solar maximum output day is not coincident with the RPU peak day. This would require that RPU have capacity available for its peak day when the solar output was reduced from its maximum. The results from the RPU analysis are essentially the same as indicated in the referenced paper.

Figure V-1
Maximum RPU System Peak Day



[1] Statistical Relationship Between Photovoltaic Generation and Electric Utility Demand in Minnesota (1996-2002), Taylor, Mike, Minnesota Department of Commerce State Energy Office

Figure V-2
Maximum Solar Array Day



Wind

Wind power is being installed in several states with wind regimes suitable for their installation. In general, the units are in the 600kW to 750kW size range and are positioned in clusters of several machines. A 750kW machine has a rotor diameter of 164 feet and is mounted 164 feet above the ground. The output of the units is dependent on the average wind speed of the region. Table V-7 lists several operating projects, their average energy and capacity factor.

Table V-7
Wind Project Statistics

Site	Size of Unit	Average Output per Unit	Capacity Factor
Cedar Falls, IA	750kW	1,800MWh	30%
Searsburg, VT	550kW	1,220MWh	27%
NPPD	750kW	2,100MWh	32%
Glenmore, WI	600kW	1,630MWh	31%

From the list and other projects that Burns & McDonnell has evaluated in regions with similar wind regimes to Minnesota, the energy output from the machines results in an approximate 30 percent capacity factor. Operation and maintenance costs are estimated at $0.015 per kWh. Estimates of the energy cost from the machines for RPU considering capital and operating costs are in the range of $41to $53 per MWh. This assumes retirement of the debt in 15 years at an interest rate of 6 percent. Sales of output from wind power developments will be priced to include discounts for the energy credits from federal and state levels. In addition, green tags are being traded which provides another revenue stream for renewable projects.

Minnesota created a 1.5¢ per kilowatt-hour state renewable energy production incentive (REPI) for the first 100 MW of installed capacity of small wind generation projects. This state REPI was expanded by the 2003 Minnesota Legislature to be available to an additional 100 MW of small wind projects.

The energy produced by a wind generator is a non-dispatchable energy. Therefore, it has a limited capacity value. MAPP accreditation for wind resources is approximately 10 to 15 percent. Therefore, RPU would need to install approximately 8.5MW of traditional capacity for every 10MW of wind turbines installed to equal installation of a traditional resource to meet its MAPP capacity and reserve obligations.

Biomass

Biomass is typically used as a fuel stock for steam fired boilers in the production of electricity. Types of vegetation used for biomass fuel include wood waste, switchgrass, and certain forms of specific woody crops, such as bamboo. Biomass plants are typically rated below 50 MW due to the area required to acquire sufficient fuel for the plant. The lack of economies of scale pushes the capital cost of these plants up into the $1500 to $2000 per kW range for capital costs. Fuel for the biomass plants requires collection from dispersed areas by truck and delivery to the plant site.

There is an estimated 7000 MW of biomass fired power plants in the US in current operation. The plants produced approximately 39,000,000MWh of energy and consumed approximately 60 million tons of fuel. Reports from the Bioenergy group of Oak Ridge National Laboratories estimate the average cost of electricity from the plants is about $90 per MWh.

Under Minnesota Statute 2003, Chapter 216B, municipal waste is defined as a biomass fuel. RPU has access to energy derived from this biomass resource from the Olmsted Waste to Energy Facility (OWEF). The OWEF is a solid waste fueled unit that currently produces approximately 1.9MW. The plant has sufficient refuse available to support an estimated additional 5MW. RPU is in discussions with the county to purchase the output. The plant has operated with an historic 90 percent availability. A 5MW waste to energy plant would satisfy the renewable energy requirements of RPU under the Minnesota regulations until approximately 2023.

Fuel Cells

Although not strictly a renewable resource plant, fuel cells have been under development as a major alternative to traditional electrical generation methods. Fuel cells based on phosphoric acid have been in commercial operation for about ten years. These units are typically sized at a 200kW level. They are being deployed in certain high energy cost areas. Current phosphoric acid fuel cells are producing electricity with an efficiency of about 30-35 percent. An estimate of the stack life indicates that they will need to be replaced every 5 to 6 years. The estimated stack replacement cost is $100,000 for a 200kW unit, resulting in fixed maintenance cost of $83 to $100/kW-yr.

Fuel cells being considered for small commercial and residential application based on proton exchange membrane technology are entering the pre-commercial testing phase and have additional research required prior to being readily available as a commercially available technology. Combined heat and power concepts are working to increase the overall efficiency; however, they are in the early stages of development. Testing is indicating that reliability and the packaging approach for ease of repair and maintenance needs to be improved.

Molten carbonate (MC) fuel cells are currently being deployed on a pre-commercial test basis in several locations. These units operate at higher temperatures than the normal fuel cells and are being targeted for large utility and industrial applications. Units are being demonstrated on coal bed methane and land fill gas. The MC units are expected to operate at efficiencies approaching 60%.

The hope for fuel cells is their ability to operate on hydrogen and produce limited noxious emissions. Currently, almost all fuel cells operate on either methane gas from landfills or coal beds and pipeline natural gas due to the limited availability of hydrogen.

RPU is conducting fuel cell research with the University of Minnesota-Rochester (UMR). The Hybrid Energy System Study (HESS) project's primary objective is to complete the static and dynamic evaluation of fuel cell technology using a 1200-watt fuel cell system installed in the RPU headquarters building in Rochester. Phase I which was completed last October, acquainted RPU and UMR with the latest in fuel cell technology that is being used in the commercial market. The fuel cell system performance was analyzed and compared with respect to efficiency, reliability, availability and serviceability.

With the completion of the Phase I basic study on fuel cells, the RPU/UMR partnership will move early in 2005 to a project level that begins to make full use of fuel cell capabilities. Fuel cells typically run at an efficiency level of about 40% when generating electricity. A major part of the efficiency loss is in the heat generated during the fuel cells operation. Capturing this heat and making use of it as part of a system's energy solution is the focus of Phase II. In particular, we will integrate a fuel cell and a geothermal (GX) heating system, therefore, capturing the heat generated by the fuel cell and raising the efficiency of the system to over 80%. During summer time operation, this extra heat could be used to provide more energy to heat hot water, swimming pools, etc.

Renewable Portfolio Program

RPU is committed to not only providing its required portion of renewable energy to satisfy the requirements of the Minnesota Statute 216B, but to integrate renewable energy where it makes good business sense to do so. The energy above CROD amount provided by SMMPA is shown in Table V-8 for 2016 to the end of the study period. The growth in renewable energy required between 2005 and 2016 can be met through the energy from the Zumbro River hydro facility. Using the ten percent requirement from the Statute, the required amount of energy beyond 2015 can be determined. The amount of energy estimated to be available from the Zumbro River hydro facility is also shown. The resulting renewable energy required beyond that currently provided is shown in Table V-8.

Using the average capacity factors for the fixed plate solar arrays from Table V-6 and the average 30 percent capacity factor for wind units, the average amount of solar and wind capacity required to meet the RPU annual renewable energy requirements can be estimated. These estimates were derived from using the Revised Energy Forecast from Table V-5. Table V-8 provides the estimates. The energy above CROD requirements predicted in Table V-8 assumed the energy savings are evenly distributed across all hours of the year. To the degree the savings accrue more from programs reducing energy above or below the CROD level, the estimates in Table V-8 will vary actual results.

Table V-8
Estimated MW of Wind or Solar Required to Meet the RPU Renewable Energy Requirements Post 2015

Year	Energy Above CROD (MWh)	Renewable Requirement (10%)	From Zumbro River Hydro	Resultant Renewable Req.	Solar Capacity Required (MW)	Wind Capacity Required (MW)
2016	70,589	7,059	9,000	-1,941	0.0	0.0
2017	82,305	8,230	9,000	-770	0.0	0.0
2018	96,279	9,628	9,000	628	0.0	0.0
2019	112,425	11,243	9,000	2,243	2.0	0.9
2020	134,112	13,411	9,000	4,411	4.0	1.7
2021	159,422	15,942	9,000	6,942	6.3	2.6
2022	190,077	19,008	9,000	10,008	9.1	3.8
2023	224,847	22,485	9,000	13,485	12.3	5.1
2024	264,465	26,446	9,000	17,446	15.9	6.6
2025	305,705	30,570	9,000	21,570	19.7	8.2
2026	349,486	34,949	9,000	25,949	23.7	9.9
2027	396,145	39,614	9,000	30,614	28.0	11.6
2028	445,435	44,543	9,000	35,543	32.5	13.5
2029	496,336	49,634	9,000	40,634	37.1	15.5
2030	549,802	54,980	9,000	45,980	42.0	17.5

The solar and wind resources' ability to provide a certain amount of capacity relief was reviewed. The peak needs of RPU and the solar availability are shown in Figures V-1 and V-2. The figures indicate that the peak requirements extend beyond the time period when solar is available. Cloud cover can also significantly reduce the solar output below the demand required of RPU. Therefore, for supply reliability, additional resources are required to provide energy when the solar output is unavailable. The MAPP accreditation process for solar array output from the above paper indicates that for the Minneapolis solar arrays, the units were able to have capacity accredited between 8 percent and 44 percent of their AC ratings. Correlation of the specific RPU data will need to be made to determine the proper estimated accreditation for solar arrays in the RPU service territory.

Allowing wind the MAPP upper 15 percent capacity credit indicates that only a portion of the wind capacity may be available across the peak. Therefore, the renewable portfolio options may require the installation of peaking capacity to support them during times when they are unavailable and load demand is still higher than the existing resource capability. For the wind portfolio, approximately 85 percent of the capacity in the traditional options could be required.

If the OWEF increases its output to 5MW, the plant would produce approximately 32,850 MWh per year, assuming a 75 percent capacity factor. Since this unit counts as renewable energy and under the Statute utilities are to provide 1 percent of their energy from biomass, it could satisfy the RPU biomass renewable requirements through the study period. When combined with the Zumbro River hydro facility total renewable requirements could be satisfied until approximately 2027. Table V-9 provides an assumed purchase scenario. Due to the requirement in the REO of obtaining 1 percent of energy from biomass, the output of the OWEF will be required beginning in 2005.

Table V-9
RPU Estimated Annual Renewable Energy Requirements (MWh)

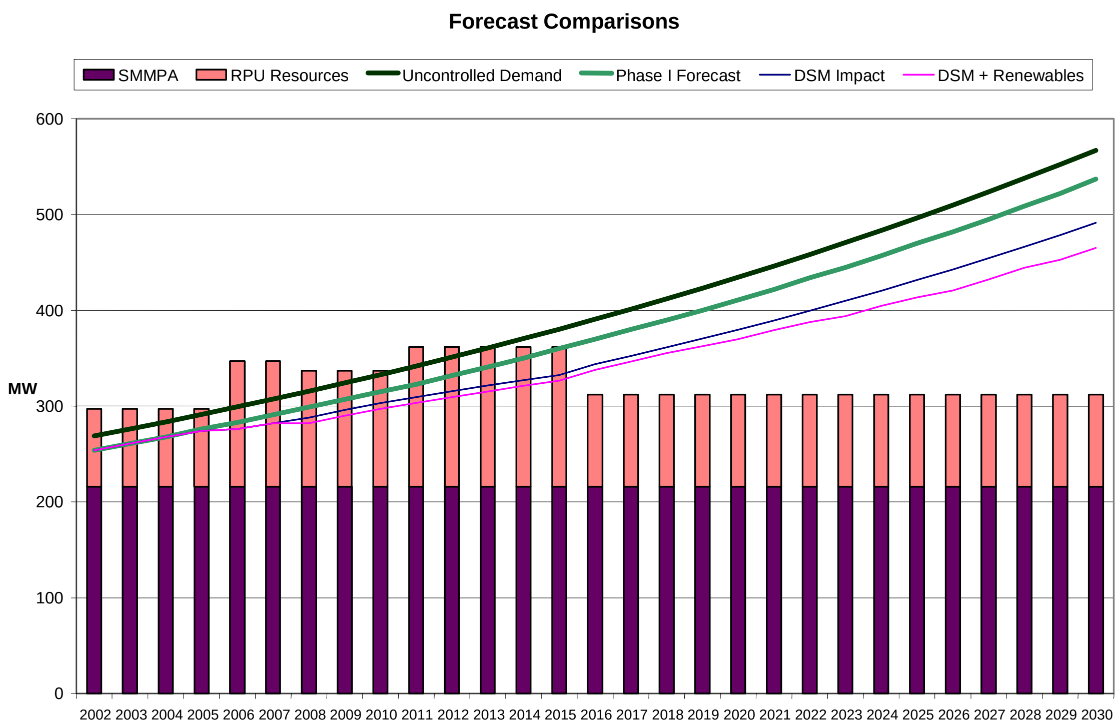
			Available from OWEF			
Year	Renewable Requirement (10%)	From Biomass	1.9MW @ 75%CF	5MW @ 75%CF	From Zumbro River	Total Hydro & Biomass
2016	7,059	71	12,483		9,000	21,483
2017	8,230	82	12,483		9,000	21,483
2018	9,628	96	12,483		9,000	21,483
2019	11,243	112	12,483		9,000	21,483
2020	13,411	134	12,483		9,000	21,483
2021	15,942	159	12,483		9,000	21,483
2022	19,008	190	12,483		9,000	21,483
2023	22,485	225		32,850	9,000	41,850
2024	26,446	264		32,850	9,000	41,850
2025	30,570	306		32,850	9,000	41,850
2026	34,949	349		32,850	9,000	41,850
2027	39,614	396		32,850	9,000	41,850
2028	44,543	445		32,850	9,000	41,850
2029	49,634	496		32,850	9,000	41,850
2030	54,980	550		32,850	9,000	41,850

Note: All energy values in MWh

DSM and Renewable Impacts on RPU Supply Needs

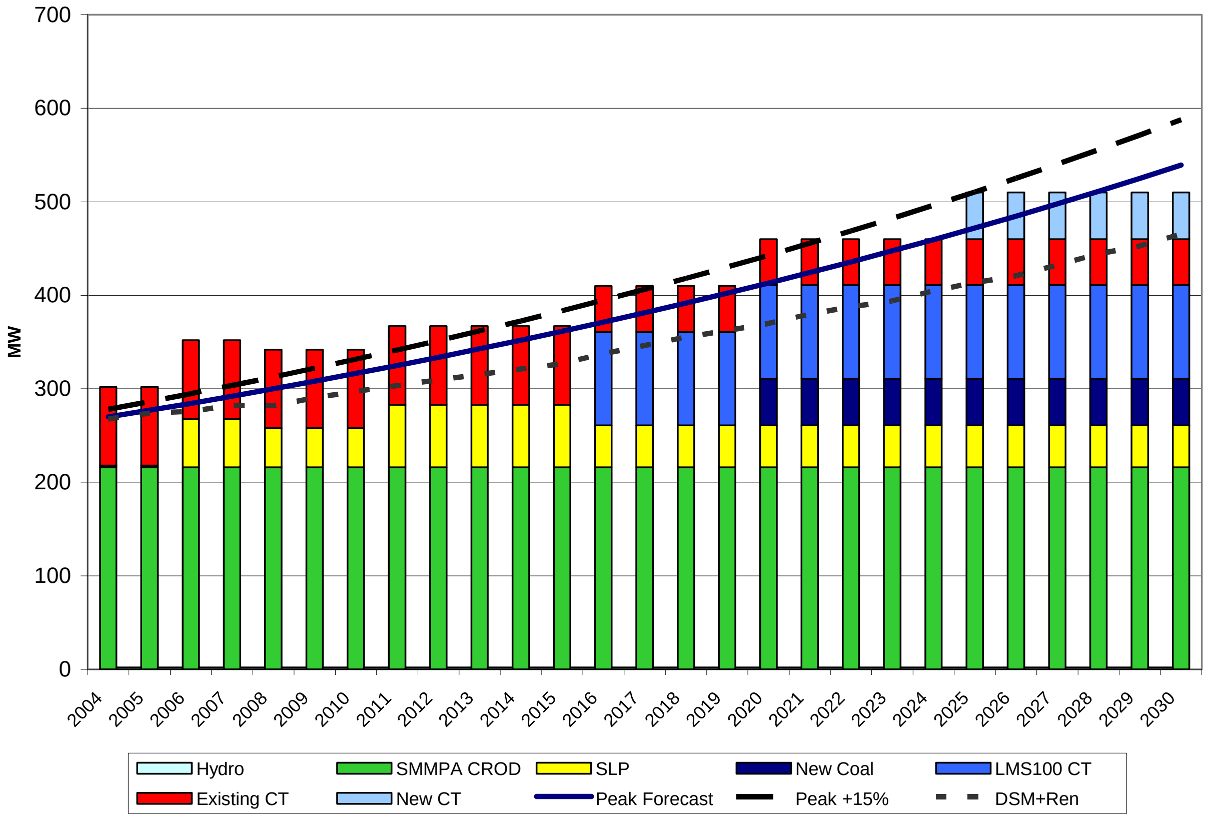
The balance of loads and resources using the DSM and renewable impacts was modified to include the above forecasts. The resulting impacts are shown in Figure V-3.

Figure V-3
Comparison of Base and Revised Forecasts
With DSM and Renewable Impacts



The impacts to the forecast indicate that the projected impacts of DSM and renewables do not delay the year when RPU becomes capacity deficit, however, they substantially reduce the amount of capacity needed. In addition, they delay the need for additional capacity in the future. Figure V-4 is the balance of loads and resources of the recommended traditional resource plan. As shown, the impact of the DSM and renewables on the forecast allows a delay in the installation of the LMS-100 combustion turbine by about 2 - 3 years. The impacts also allow a delay in the need for the coal unit by a similar period.

Figure V-4
Impact of DSM and Renewables
On Lowest Evaluated Traditional Resource Plan
Balance of Loads and Resources



Conclusions and Recommendations

Based on the review of the information provided by RPU and the analysis developed in this study, Burns & McDonnell has developed the following conclusions and recommendations about the DSM programs and renewable energy alternatives available to RPU.

1. The review of the DSM end use surveys and benefit cost ratios provided an indication of the amount and value of various conservation programs to the RPU customer base that is sufficient to use for planning purposes.

2. The estimates of energy and demand reductions from the programs with benefit cost ratios greater than one is sufficient to warrant study by RPU in determining the impact on rates for development of various programs and the impact on forecasts for energy and demand.

3. Considering the forecast, RPU has several years before it is in a capacity deficit condition due to load needs. Estimates of DSM and renewable impacts to the forecast provide the opportunity for RPU to delay the installation of resources by

two to three years, depending on the successful acceptance of the DSM programs by the RPU customers.

4. The development of the MISO Day 2 market will make day ahead pricing more predictable and potentially provide RPU with the opportunity to engage customers in demand adjustments based on the cost of energy. The current Partners program could see a decrease in the number of MW under control due to more efficient air conditioners being installed on the system and potential fuel switching of water heaters. These two developments are an indication that RPU should consider realigning its approach to demand reductions on the customer side of the meter. Because of this need, RPU should prepare a pilot program for implementation of demand response type programs across the residential, commercial and industrial classes in order to gain experience and begin shifting away from the direct control programs to market based programs.

5. RPU's renewable obligations under the Minnesota Statute Chapter 216B can be met for several years through purchase of energy from the OWEF and the Zumbro River hydro facility. If the OWEF facility is expanded, as is being considered, RPU renewable energy requirements could be satisfied until approximately 2027 with these two resources.

6. Discussions with the OWEF should proceed to determine if additional output is available. If it is not, then wind energy should be pursued as the next renewable option. Based on the cost and output of photovoltaic units, solar photovoltaic is the most expensive renewable option for the RPU to pursue.

7. Based on information from RPU, the SMMPA is in discussions on acquisition of additional resources which could affect the cost of capacity and energy under the CROD. At the current time, there is insufficient information to be able to determine how DSM programs could reduce the impact of these potential costs. If SMMPA moves ahead with resource acquisitions based on RPU impacts to the SMMPA resource mix, RPU should discuss with SMMPA the ability of DSM options to reduce the resource need impacts to SMMPA.

*****

Part VI

Financial Forecast

The results of the resource planning, demand side management and renewable assessments were reviewed on an incremental cost approach to determine lower evaluated options. In order to bring these options together to determine the recommended RPU future, a financial forecast model was developed by RPU to incorporate the total costs of RPU. This model allowed a complete evaluation of future costs, the impact to average rates and other financial factors of interest to RPU. This part of the report provides a discussion of the model and the results.

Financial Model

The model was developed by Bryan Blom of the RPU staff. It is a very flexible tool that will provide RPU with the capability to do scenario analysis rapidly, with a variety of measurements to gauge the benefits of certain futures. The model incorporates all of the RPU costs of operations, investments, and financial targets such as for cash balances and reserve accounts.

The financial model was used to analyze the following futures:

- The recommended expansion plan from Part IV with the forecast unaffected by demand side management,
- The recommended plan adjusted by using the normal demand side management forecast with SLP operating on coal and adjustments to the new resources,
- The recommenced plan adjusted by using the normal demand side management forecast with SLP operating on natural gas and the coal unit replaced with gas-fired capacity,
- The recommended plan adjusted by using the aggressive demand side management results with SLP operating on coal and adjustments to the new resources,
- The recommended plan adjusted by using the aggressive demand side management results with SLP operating on natural gas and the coal unit replaced with gas-fired capacity.

Input Assumptions

A variety of assumptions were made to the financial model. The main driver for the model is the energy forecast. The energy forecast for the three futures is summarized in Table VI-1. The demand forecast is also included.

Table VI-1
Financial Model Load Forecast

	System MWH Requirements		System KW Peaks	
Year	No DSM	Aggr DSM, Coal Gas Mix / Aggr DSM, All Gas	No DSM	Aggr DSM, Coal Gas Mix / Aggr DSM, All Gas
2005	1,377,188	1,369,244	275,532	273,943
2006	1,414,592	1,355,882	283,016	271,270
2007	1,452,466	1,379,800	290,593	276,055
2008	1,495,753	1,405,507	299,254	281,198
2009	1,532,736	1,424,557	306,653	285,009
2010	1,573,748	1,448,206	314,858	289,741
2011	1,615,858	1,473,719	323,283	294,845
2012	1,664,019	1,504,173	332,918	300,938
2013	1,705,167	1,529,146	341,151	305,934
2014	1,750,796	1,559,194	350,280	311,946
2015	1,797,648	1,589,834	359,653	318,076
2016	1,850,380	1,635,664	370,203	327,245
2017	1,897,159	1,672,869	379,562	334,689
2018	1,947,044	1,717,704	389,543	343,659
2019	2,000,216	1,762,000	400,181	352,521
2020	2,058,896	1,812,798	411,921	362,684
2021	2,108,877	1,857,723	421,920	371,672
2022	2,167,552	1,907,527	433,659	381,637
2023	2,225,664	1,958,667	445,286	391,868
2024	2,289,846	2,017,133	458,127	403,565
2025	2,346,599	2,067,127	469,481	413,568
2026	2,410,705	2,122,550	482,307	424,656
2027	2,475,342	2,180,536	495,239	436,257
2028	2,547,984	2,244,526	509,772	449,060
2029	2,612,433	2,301,298	522,666	460,418
2030	2,681,160	2,364,171	536,416	472,997
2031	2,753,599	2,426,667	550,909	485,500
2032	2,827,996	2,490,816	565,794	498,335
2033	2,904,405	2,556,663	581,081	511,508
2034	2,982,881	2,624,252	596,781	525,031

The load forecast was used to derive estimates for a variety of other assumptions, such as:

- Energy dispatch from RPU sources, including market sources, above the SMMPA supplied energy,
- Generation fuel expense,
- Purchased power expense for energy, capacity, and transmission,
- Administrative and general costs,
- Distribution and substation additions,
- Retail revenue forecasts.

Forecasts for investment in other projects, such as for transmission upgrades, capital investments in plant, and other improvements were provided by the respective operating divisions of RPU. The Silver Lake Plant was assumed to have the recommended environmental modifications from the Utility Engineering report "Rochester Public Utilities Emissions Control Feasibility Study, Silver Lake Plant," Dec 2004 in the futures with coal. The budgets for the demand side management and marketing programs were included based on the level of DSM considered in the forecast. The list of input assumptions is included in Appendix V.

Methodology

The financial model uses the energy forecast and estimated energy price from the resources available to determine the amount of energy derived from each source. If the load level is at or below the 216MW level of the SMMPA contract, then the energy is assumed to come from SMMPA. If the load is above the 216MW level, then the lowest cost resource is dispatched to provide the energy with the exception that small load increments were dispatched first from peaking units until the point where the increment was high enough to feasibly dispatch baseload generation.

The economic impacts of resource additions were determined based on the estimated capital, fixed and variable operating and maintenance costs. The targeted financial goals for debt service coverage ratios, average cash balances and other targets based on capital investments were included. In-service years and the amount of capacity added were adjusted in the futures with demand side management included to reflect the benefits to delays in and amounts of capital investment.

Estimates of purchases from the market were made using a forecast market demand and energy price. For certain years, market capacity was purchased on a seasonal basis to provide the necessary capacity shortfall rather than install a new resource. Also, when market energy was estimated to be lower cost than an RPU resource's energy cost, the market was used to provide the energy.

The operation of the SLP to meet wholesale energy and steam production contract obligations was modeled. The operations included estimated energy and steam production based on current discussions with counter parties to the contracts.

The operation and capital budgets of each RPU division were incorporated to provide a complete financial picture of the utility. The revenue requirements were then used to determine the amount of adjustment to rates necessary to meet those requirements. Average impact to retail rates and customer average bills were also estimated. The model covers a thirty year time period from 2005 to 2034.

Externalities

The values of externalities were included in this analysis. The values of externalities used by the Minnesota Public Utilities Commission (Rural) for utilities to evaluate externalities are shown in Table VI-2. These values were adjusted for the gross domestic price inflator (4.4%) for 2004. A midpoint range for the adjusted values was selected for use in the analysis. These values are also shown in Table VI-2.

Table VI-2
Externality Values

	Low Value		High Value		2004
	2003	2004	2003	2004	AVG
PM10	$645.00	$673.38	$981.00	$1,024.16	$848.77
CO	$ 0.24	$ 0.25	$ 0.47	$ 0.49	$ 0.37
Nox	$ 21.00	$ 21.92	$117.00	$122.15	$ 72.04
Pb	$461.00	$481.28	$514.00	$536.62	$508.95
CO2	$ 0.34	$ 0.35	$ 3.56	$ 3.72	$ 2.04

The emission rates from the resources considered in the financial model are summarized in Table VI-3. The emissions were placed on a dollar per MWh basis for use with the expected dispatch MWh determined from the financial model. Externalities on contract and market purchases were also included to reflect one half of the purchases from new coal units and one half from combined cycle gas units.

Table VI-3
Emission Rates
(lb/MWh)

			SLP			
Emission	LMS100	CC2	Coal	Gas	New Coal	Market
SO2	0	0	4.85	0.01	0.96	0
PM10	0.14	0.0166	0.21	0.07766	0.17	0.07
CO	5.85	2.96	0.28	0.924	1.44	0.117
Nox	0.87	1.52	1.60	3.08	0.67	0.084
Pb	0	0	0.000606	0.0000055	0.0002406	0
CO2	1125.48	1051.2	2,460.97	1126	2761.51	825

Renewable Options

The values for the average energy costs from the expected resources and certain renewable resources are shown in Table VI-4. The RPU currently purchases renewable energy from the Olmsted County Waste to Energy Facility, which counts towards the utilities biomass energy requirement. This facility is considering increasing the energy production which could provide additional biomass energy for RPU. Energy from a solar installation in the RPU service territory is currently being purchased at the net metered residential energy rate. Wind energy is purchased through the SMMPA. The amount of predominate renewable energy is from the Zumbro River hydro-electric facility.

Table VI-4
Average Energy Costs with Externalities
(2004$ per MWh)

Option	Fixed O&M	Var O&M	Purchase/ Fuel	Transmission	Externality	Total
SLP Coal	$13.85	$6.59	$25.34		$2.65	$48.43
New Coal	$ 3.01	$2.15	$11.07	$5.00	$2.91	$24.14
New Gas	$ 6.73	$4.01	$58.27		$1.13	$70.14
LMS 100	$ 3.75	$3.30	$53.79		$1.24	$62.08
Market			$35.88	$5.00	$1.89	$42.77
Solar PV			$75.10			$75.10
OWEF			$60.00	$5.00		$65.00
Wind			$33.44	$5.00		$38.44
Zumbro		$2.17				$2.17

Although it is acceptable to consider energy costs on a one for one basis between traditional and renewable resources, the capacity cannot always be considered in a comparable fashion. This is due to the non-dispatchability of most renewable options. For instance, the utility has to take energy from a wind turbine when the wind blows. The energy availability and the utility needs may not necessarily coincide. The line-up of solar energy with the RPU demand is shown in Part V and demonstrates this issue.

RPU operates in the Mid-Continent Area Power Pool (MAPP) reliability region. Utilities within this region must maintain a reserve margin of 15 percent or be assessed a penalty. In order to meet this requirement, resources must meet certain capacity tests. From past experience with wind turbine and solar array capacity, MAPP has established that wind capacity provides only 15 percent of the equivalent traditional resource capacity value and solar provides approximately 40 percent (summer season). This means that if RPU wanted to install wind or solar capacity to meet its MAPP reserve requirements, which for every MW of traditional resource considered either 6.67MW of wind or 2.5MW of solar would be needed. The impact of these requirements on the average cost of energy from the resources is shown in Table VI-5.

Table VI-5
Impacts of Equivalent Capacity on Energy Cost
(Average Annual Debt Service)

Option	$/MWh	Capacity Factor-%
SLP Coal	$11.73	40
New Coal	$16.99	80
New Gas	$32.48	20
LMS 100	$36.30	20
Solar PV	$852.50	20
Wind	$222.91	30

Based on the evaluation of the externalities and MAPP accreditation impacts, RPU has determined that renewable energy will be used to displace traditional resource energy where economic. However, renewable resources will not be considered to meet future capacity obligations.

Renewable energy from the Zumbro River facility was included in the financial model as the primary renewable resource, wind energy under the SMMPA program included at its historical average, and with OWEF assumed to be the biomass resource.

Results

Resource Plan

The impact of the demand side management efforts on the load forecast are shown in Part V, Figure V-1 and 2 for the demand and energy respectively. Figure V-4 provides the potential impacts the forecast could have to the resource needs in the traditional resource plan. The reduction in the demand and energy forecast provides an opportunity to delay the gas resource considered for 2016 and the in service year and amount of capacity for the coal resource considered in 2020. In the financial model, the combustion turbine considered for installation in 2016 was delayed two years and the coal unit was reduced to 25MW and its in service date delayed to 2025.

Rates

Figure VI-1 and 2 provide the results based on average retail rate impacts and average customer bills. As seen, there are significant advantages in the demand side management impacts on both rates and average bills. When considering the cost impacts due to the futures with and without coal, it is seen that the coal case provides economic benefits. The rate impacts determined from the analyses are summarized in Figure VI-3. RPU in any of the futures is expected to need rate increases of from 1 to 3 percent in almost each year of the assessment. The differences in the expected and aggressive demand side management scenarios were not significant and only the aggressive forecast is included here. The more detailed results of the financial model analyses are included in Appendix V.

Figure VI-1
Retail $/MWH-Major Customer Classes

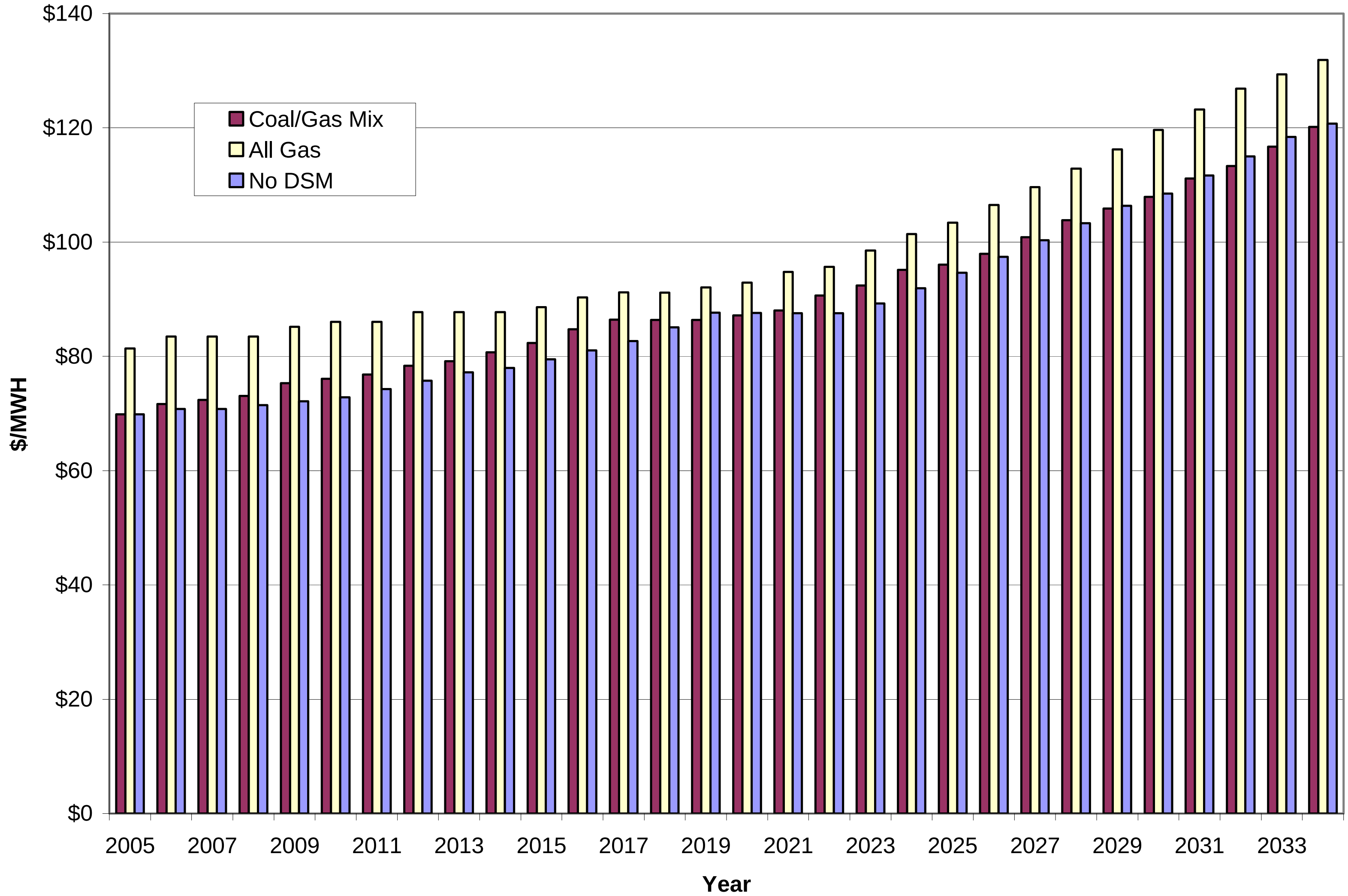


Figure VI-2
Average Annual Bill-Major Customer Classes

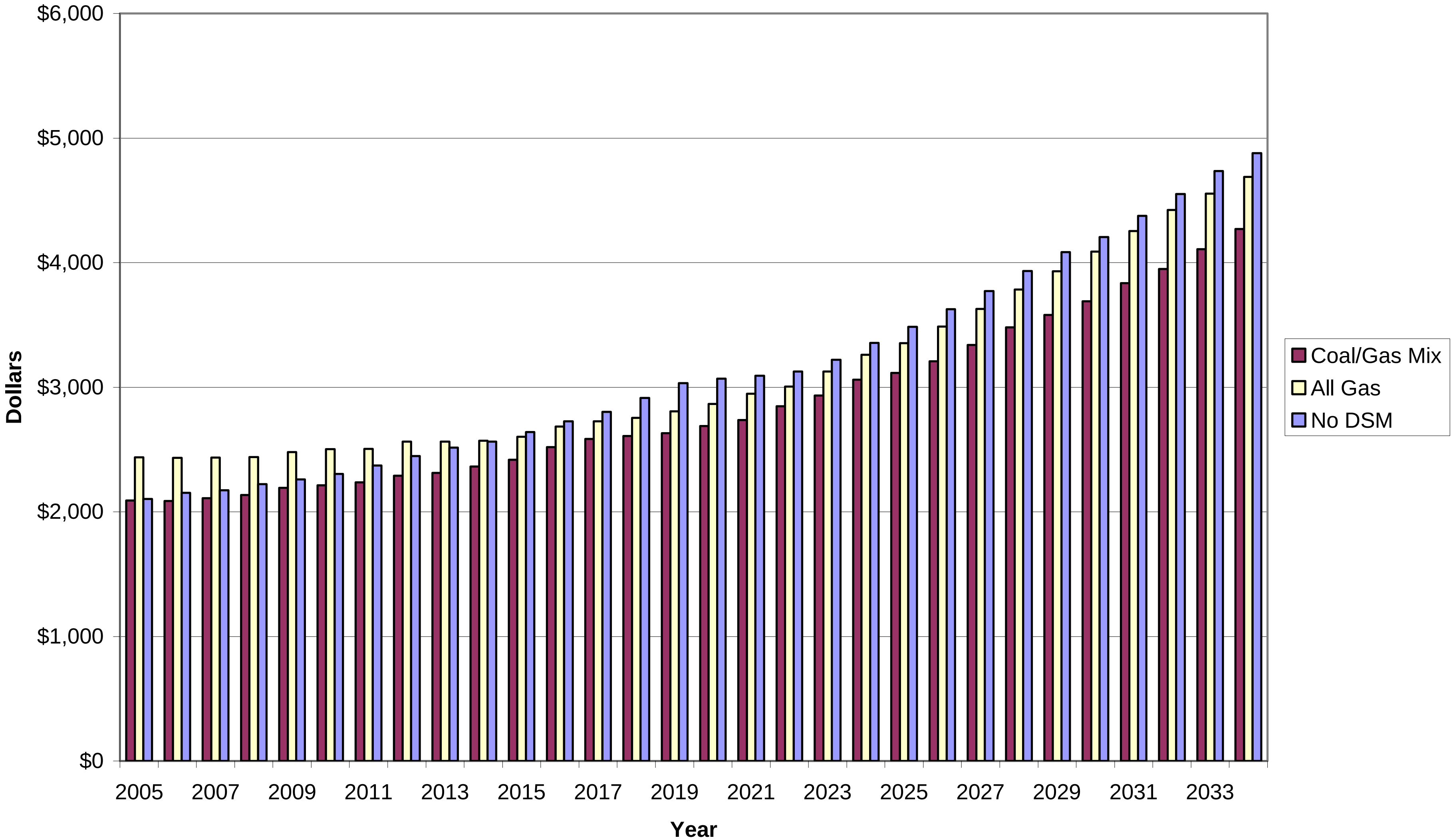
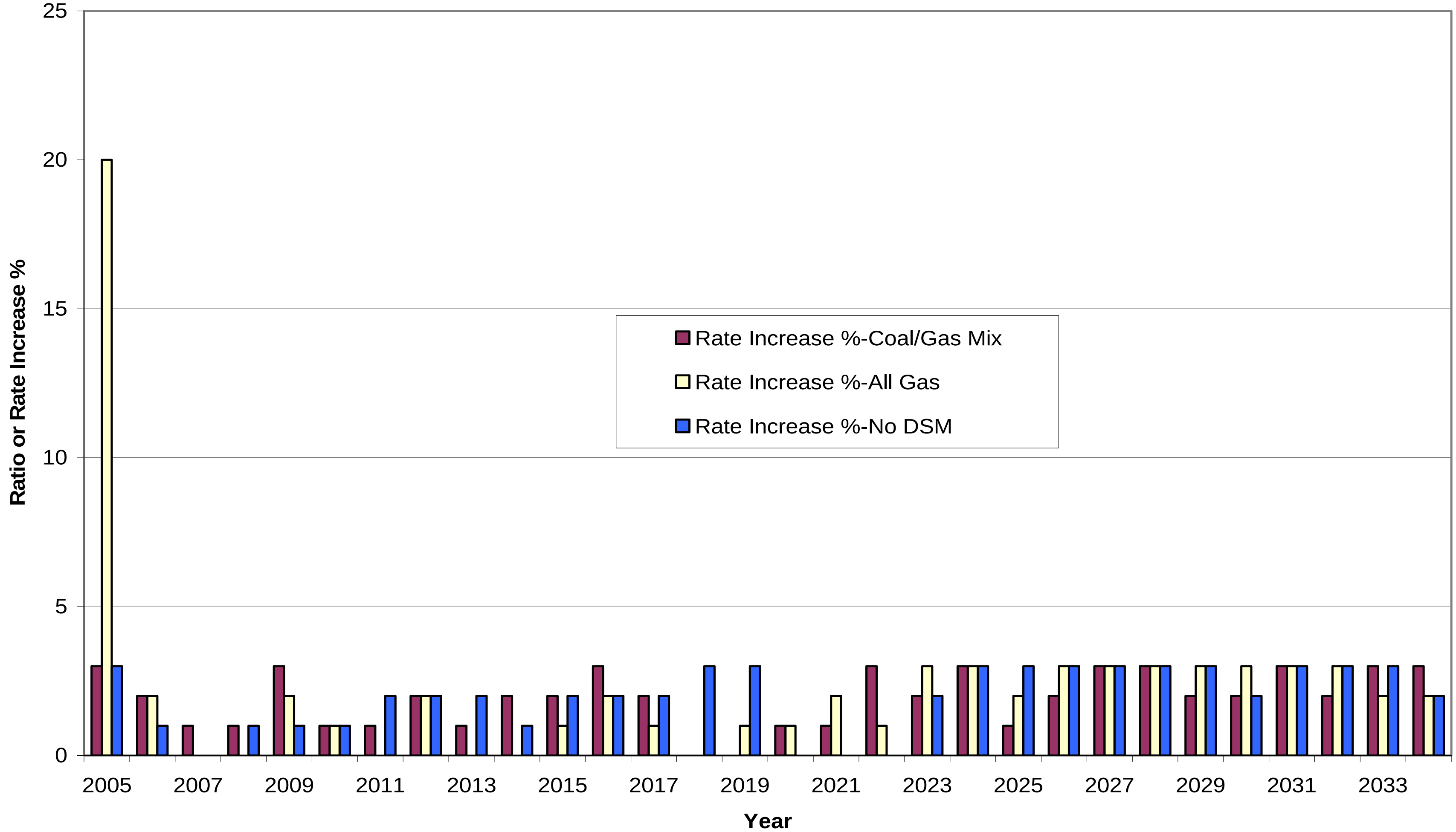


Figure VI-3
Percentage of Annual Retail Rate Increase



As seen from the above graphs, the DSM cases with the coal and gas fuel scenario are the only cases that help to reduce both the average rates and customer bills.

Emissions

The emissions from each of the futures were considered from both absolute tons per externality and the cost aspect using the Minnesota value for externalities. Table VI-6 provides the summary of tons emitted by externality based on the energy dispatch used for the RPU retail resource future over the thirty years of the analysis. As shown, there is a substantial advantage to the demand side reductions. The costs of the externalities and the total costs of the specific future are included in Table VI-7.

Table VI-6
Total Tons of Emissions by Scenario

Scenario	SO2	Nox	PM10	Pb	CO	CO2
Original Forecast	7,808	4,587	770	1.25	9,811	10,472,370
Normal DSM Coal & Gas	5,228	3,105	485	0.79	7,048	6,263,420
Normal DSM All Gas	379	5,086	296	0.10	8,341	3,784,419
Aggressive DSM Coal & Gas	4,931	2,886	448	0.73	6,504	5,720,385
Aggressive DSM All Gas	343	4,714	272	0.09	7,644	3,474,437

Table VI-7
Retail Portion of RPU Costs of Various Plans with Externalities
(2004$ 000's)

Scenario	Retail Revenue	Externalities	Total
Original Forecast	$ 5,649,613	$22,308	$ 5,671,921
Normal DSM Coal & Gas	$ 5,134,851	$13,390	$ 5,148,241
Normal DSM All Gas	$ 5,672,269	$ 8,325	$ 5,680,594
Aggressive DSM Coal & Gas	$ 5,104,864	$12,236	$ 5,117,100
Aggressive DSM All Gas	$ 5,569,761	$ 7,646	$ 5,577,408

Conclusions

Based on the analysis performed for this study, Burns & McDonnell has developed the following conclusions:

1. The uncertainty surrounding the conversion of the electricity wholesale market in the RPU region from its traditional operation to its new operation under MISO and the existing transmission limitations for importing power into the RPU area makes it necessary for RPU to continue to have capacity available within its service area for reliability and economic purposes.

2. The use of traditional resources to meet the RPU capacity obligations is lower cost than the use of wind or solar equivalent capacity. Energy costs from certain renewable options can be attractive when compared to the energy costs from coal, gas, or market resources.

3. The impacts of demand side management allow RPU to delay and reduce the amount of capacity required when compared to the forecast without significant demand side management effects included.

4. The future evaluated with coal and gas energy and aggressive demand side management was the only future that provided both lower average rates and lower average total bills when compared to the other futures. This ranking is not changed with the inclusion of externalities.

5. The emissions from the aggressive demand side management future with coal and gas are approximately one-half of the emissions from the traditional resource future.

Recommendations

Based on the above conclusions and the analyses performed, Burns & McDonnell provides the following recommendations for consideration by RPU.

1. Due to the need for future capacity additions internal to RPU, RPU should pursue the acquisition of property to install additional combustion turbine capacity. The property should be located in close proximity to high capacity electric and gas transmission lines.

2. RPU should pursue emission control upgrades to the SLP facility to allow continued operations while meeting ongoing environmental regulations and follow the general course of operations as modeled in the DSM futures with coal and gas fuels in the operating mix.

3. Improved transmission import capability should be reviewed with area utilities to allow increased access to market capacity. Although the plans anticipate future resource additions, there is also continued reliance on market purchases to meet future load growth.

4. RPU should monitor the operations of the MISO Day 2 market to determine how to participate in the market.

5. RPU should continue to design and market DSM programs to achieve the levels of forecast reductions for demand and energy. Periodic comparison of actual results to those forecasts should be made to determine if adjustments in the forecast results is necessary.

6. RPU should take advantage of renewable energy from the Zumbro River resource to the full extent of its output. The renewable energy from the OWEF should be considered to provide the RPU biomass energy requirements. Purchases above the requirements should be compared to the cost of other energy available.

*****

Appendix I – Load Forecast (Without DSM Impacts)

Annual Peak Demand and Energy Requirements

Year	Peak (MW)	Esc.	Energy (MWh)	Esc.	LF
2003	261.3	2.7%	1,306,276	9.6%	57.1%
2004	268.4	2.7%	1,344,534	2.9%	57.2%
2005	275.6	2.7%	1,377,767	2.5%	57.1%
2006	283.1	2.7%	1,414,967	2.7%	57.1%
2007	290.7	2.7%	1,453,171	2.7%	57.1%
2008	298.6	2.7%	1,495,732	2.9%	57.2%
2009	306.6	2.7%	1,532,702	2.5%	57.1%
2010	314.9	2.7%	1,574,085	2.7%	57.1%
2011	323.4	2.7%	1,616,585	2.7%	57.1%
2012	332.2	2.7%	1,663,932	2.9%	57.2%
2013	341.1	2.7%	1,705,059	2.5%	57.1%
2014	350.3	2.7%	1,751,096	2.7%	57.1%
2015	359.8	2.7%	1,798,375	2.7%	57.1%
2016	369.5	2.7%	1,851,046	2.9%	57.2%
2017	379.5	2.7%	1,896,798	2.5%	57.1%
2018	389.7	2.7%	1,948,012	2.7%	57.1%
2019	400.3	2.7%	2,000,608	2.7%	57.1%
2020	411.1	2.7%	2,059,202	2.9%	57.2%
2021	422.2	2.7%	2,110,100	2.5%	57.1%
2022	433.6	2.7%	2,167,072	2.7%	57.1%
2023	445.3	2.7%	2,225,583	2.7%	57.1%
2024	457.3	2.7%	2,290,766	2.9%	57.2%
2025	469.6	2.7%	2,347,559	2.5%	57.1%
2026	482.3	2.7%	2,410,943	2.7%	57.1%
2027	495.3	2.7%	2,476,038	2.7%	57.1%
2028	508.7	2.7%	2,548,370	2.9%	57.2%
2029	522.4	2.7%	2,611,549	2.5%	57.1%
2030	536.6	2.7%	2,682,061	2.7%	57.1%

Monthly Peak Demand and Energy Requirements

			Peak Demand (MW)			Total Energy Requirements (MWh)		
Month	Year		Annual Peak	Ratio	Peak	Total	Ratio	Total
Jan	2006		283.1	0.648	183.5	1,414,967	0.078	110,892
Feb	2006		283.1	0.645	182.6	1,414,967	0.071	100,341
Mar	2006		283.1	0.631	178.6	1,414,967	0.076	107,892
Apr	2006		283.1	0.687	194.5	1,414,967	0.073	103,354
May	2006		283.1	0.770	218.1	1,414,967	0.080	113,721
Jun	2006		283.1	0.966	273.5	1,414,967	0.091	128,980
Jul	2006		283.1	1.000	283.1	1,414,967	0.109	153,709
Aug	2006		283.1	0.984	278.7	1,414,967	0.102	144,845
Sep	2006		283.1	0.977	276.6	1,414,967	0.086	121,835
Oct	2006		283.1	0.694	196.6	1,414,967	0.079	111,608
Nov	2006		283.1	0.656	185.8	1,414,967	0.075	105,978
Dec	2006		283.1	0.687	194.5	1,414,967	0.079	111,812
Jan	2007		290.7	0.648	188.4	1,453,171	0.078	113,886
Feb	2007		290.7	0.645	187.5	1,453,171	0.071	103,050
Mar	2007		290.7	0.631	183.5	1,453,171	0.076	110,805
Apr	2007		290.7	0.687	199.8	1,453,171	0.073	106,145
May	2007		290.7	0.770	224.0	1,453,171	0.080	116,791
Jun	2007		290.7	0.966	280.9	1,453,171	0.091	132,462
Jul	2007		290.7	1.000	290.7	1,453,171	0.109	157,859
Aug	2007		290.7	0.984	286.2	1,453,171	0.102	148,756
Sep	2007		290.7	0.977	284.1	1,453,171	0.086	125,125
Oct	2007		290.7	0.694	201.9	1,453,171	0.079	114,622
Nov	2007		290.7	0.656	190.8	1,453,171	0.075	108,839
Dec	2007		290.7	0.687	199.8	1,453,171	0.079	114,831
Jan	2008		298.6	0.648	193.5	1,495,732	0.078	117,222
Feb	2008		298.6	0.645	192.6	1,495,732	0.071	106,068
Mar	2008		298.6	0.631	188.4	1,495,732	0.076	114,050
Apr	2008		298.6	0.687	205.2	1,495,732	0.073	109,253
May	2008		298.6	0.770	230.0	1,495,732	0.080	120,212
Jun	2008		298.6	0.966	288.5	1,495,732	0.091	136,342
Jul	2008		298.6	1.000	298.6	1,495,732	0.109	162,482
Aug	2008		298.6	0.984	293.9	1,495,732	0.102	153,113
Sep	2008		298.6	0.977	291.8	1,495,732	0.086	128,789
Oct	2008		298.6	0.694	207.3	1,495,732	0.079	117,979
Nov	2008		298.6	0.656	196.0	1,495,732	0.075	112,027
Dec	2008		298.6	0.687	205.2	1,495,732	0.079	118,195
Jan	2009		306.6	0.648	198.7	1,532,702	0.078	120,119
Feb	2009		306.6	0.645	197.8	1,532,702	0.071	108,690
Mar	2009		306.6	0.631	193.5	1,532,702	0.076	116,869
Apr	2009		306.6	0.687	210.7	1,532,702	0.073	111,954
May	2009		306.6	0.770	236.3	1,532,702	0.080	123,183
Jun	2009		306.6	0.966	296.3	1,532,702	0.091	139,711
Jul	2009		306.6	1.000	306.6	1,532,702	0.109	166,498
Aug	2009		306.6	0.984	301.8	1,532,702	0.102	156,897
Sep	2009		306.6	0.977	299.7	1,532,702	0.086	131,973
Oct	2009		306.6	0.694	212.9	1,532,702	0.079	120,895
Nov	2009		306.6	0.656	201.3	1,532,702	0.075	114,796
Dec	2009		306.6	0.687	210.7	1,532,702	0.079	121,116
Jan	2010		314.9	0.648	204.1	1,574,085	0.078	123,362
Feb	2010		314.9	0.645	203.1	1,574,085	0.071	111,625
Mar	2010		314.9	0.631	198.7	1,574,085	0.076	120,025
Apr	2010		314.9	0.687	216.4	1,574,085	0.073	114,976
May	2010		314.9	0.770	242.6	1,574,085	0.080	126,509
Jun	2010		314.9	0.966	304.3	1,574,085	0.091	143,484
Jul	2010		314.9	1.000	314.9	1,574,085	0.109	170,994
Aug	2010		314.9	0.984	310.0	1,574,085	0.102	161,133
Sep	2010		314.9	0.977	307.8	1,574,085	0.086	135,536
Oct	2010		314.9	0.694	218.7	1,574,085	0.079	124,159
Nov	2010		314.9	0.656	206.7	1,574,085	0.075	117,896
Dec	2010		314.9	0.687	216.4	1,574,085	0.079	124,386

Jan	2011		323.4	0.648	209.6	1,616,585	0.078	126,693
Feb	2011		323.4	0.645	208.6	1,616,585	0.071	114,639
Mar	2011		323.4	0.631	204.1	1,616,585	0.076	123,266
Apr	2011		323.4	0.687	222.3	1,616,585	0.073	118,081
May	2011		323.4	0.770	249.2	1,616,585	0.080	129,925
Jun	2011		323.4	0.966	312.5	1,616,585	0.091	147,358
Jul	2011		323.4	1.000	323.4	1,616,585	0.109	175,610
Aug	2011		323.4	0.984	318.4	1,616,585	0.102	165,484
Sep	2011		323.4	0.977	316.1	1,616,585	0.086	139,195
Oct	2011		323.4	0.694	224.6	1,616,585	0.079	127,511
Nov	2011		323.4	0.656	212.3	1,616,585	0.075	121,079
Dec	2011		323.4	0.687	222.3	1,616,585	0.079	127,745
Jan	2012		332.2	0.648	215.3	1,663,932	0.078	130,404
Feb	2012		332.2	0.645	214.3	1,663,932	0.071	117,996
Mar	2012		332.2	0.631	209.6	1,663,932	0.076	126,876
Apr	2012		332.2	0.687	228.3	1,663,932	0.073	121,539
May	2012		332.2	0.770	255.9	1,663,932	0.080	133,730
Jun	2012		332.2	0.966	320.9	1,663,932	0.091	151,674
Jul	2012		332.2	1.000	332.2	1,663,932	0.109	180,754
Aug	2012		332.2	0.984	327.0	1,663,932	0.102	170,331
Sep	2012		332.2	0.977	324.6	1,663,932	0.086	143,272
Oct	2012		332.2	0.694	230.7	1,663,932	0.079	131,246
Nov	2012		332.2	0.656	218.0	1,663,932	0.075	124,625
Dec	2012		332.2	0.687	228.3	1,663,932	0.079	131,486
Jan	2013		341.1	0.648	221.1	1,705,059	0.078	133,627
Feb	2013		341.1	0.645	220.0	1,705,059	0.071	120,913
Mar	2013		341.1	0.631	215.3	1,705,059	0.076	130,012
Apr	2013		341.1	0.687	234.4	1,705,059	0.073	124,543
May	2013		341.1	0.770	262.8	1,705,059	0.080	137,035
Jun	2013		341.1	0.966	329.6	1,705,059	0.091	155,423
Jul	2013		341.1	1.000	341.1	1,705,059	0.109	185,221
Aug	2013		341.1	0.984	335.8	1,705,059	0.102	174,541
Sep	2013		341.1	0.977	333.4	1,705,059	0.086	146,814
Oct	2013		341.1	0.694	236.9	1,705,059	0.079	134,490
Nov	2013		341.1	0.656	223.9	1,705,059	0.075	127,705
Dec	2013		341.1	0.687	234.4	1,705,059	0.079	134,736
Jan	2014		350.3	0.648	227.0	1,751,096	0.078	137,235
Feb	2014		350.3	0.645	226.0	1,751,096	0.071	124,177
Mar	2014		350.3	0.631	221.1	1,751,096	0.076	133,522
Apr	2014		350.3	0.687	240.8	1,751,096	0.073	127,906
May	2014		350.3	0.770	269.9	1,751,096	0.080	140,735
Jun	2014		350.3	0.966	338.5	1,751,096	0.091	159,619
Jul	2014		350.3	1.000	350.3	1,751,096	0.109	190,222
Aug	2014		350.3	0.984	344.9	1,751,096	0.102	179,253
Sep	2014		350.3	0.977	342.4	1,751,096	0.086	150,777
Oct	2014		350.3	0.694	243.3	1,751,096	0.079	138,121
Nov	2014		350.3	0.656	230.0	1,751,096	0.075	131,153
Dec	2014		350.3	0.687	240.7	1,751,096	0.079	138,374
Jan	2015		359.8	0.648	233.2	1,798,375	0.078	140,940
Feb	2015		359.8	0.645	232.1	1,798,375	0.071	127,530
Mar	2015		359.8	0.631	227.1	1,798,375	0.076	137,127
Apr	2015		359.8	0.687	247.3	1,798,375	0.073	131,359
May	2015		359.8	0.770	277.2	1,798,375	0.080	144,535
Jun	2015		359.8	0.966	347.6	1,798,375	0.091	163,929
Jul	2015		359.8	1.000	359.8	1,798,375	0.109	195,358
Aug	2015		359.8	0.984	354.2	1,798,375	0.102	184,093
Sep	2015		359.8	0.977	351.6	1,798,375	0.086	154,848
Oct	2015		359.8	0.694	249.8	1,798,375	0.079	141,850
Nov	2015		359.8	0.656	236.2	1,798,375	0.075	134,694
Dec	2015		359.8	0.687	247.2	1,798,375	0.079	142,110

Jan	2016		369.5	0.648	239.5	1,851,046	0.078	145,068
Feb	2016		369.5	0.645	238.4	1,851,046	0.071	131,265
Mar	2016		369.5	0.631	233.2	1,851,046	0.076	141,143
Apr	2016		369.5	0.687	253.9	1,851,046	0.073	135,207
May	2016		369.5	0.770	284.7	1,851,046	0.080	148,768
Jun	2016		369.5	0.966	357.0	1,851,046	0.091	168,730
Jul	2016		369.5	1.000	369.5	1,851,046	0.109	201,080
Aug	2016		369.5	0.984	363.7	1,851,046	0.102	189,485
Sep	2016		369.5	0.977	361.1	1,851,046	0.086	159,384
Oct	2016		369.5	0.694	256.6	1,851,046	0.079	146,005
Nov	2016		369.5	0.656	242.5	1,851,046	0.075	138,639
Dec	2016		369.5	0.687	253.9	1,851,046	0.079	146,272
Jan	2017		379.5	0.648	245.9	1,896,798	0.078	148,654
Feb	2017		379.5	0.645	244.8	1,896,798	0.071	134,510
Mar	2017		379.5	0.631	239.5	1,896,798	0.076	144,632
Apr	2017		379.5	0.687	260.8	1,896,798	0.073	138,549
May	2017		379.5	0.770	292.4	1,896,798	0.080	152,445
Jun	2017		379.5	0.966	366.6	1,896,798	0.091	172,900
Jul	2017		379.5	1.000	379.5	1,896,798	0.109	206,050
Aug	2017		379.5	0.984	373.6	1,896,798	0.102	194,168
Sep	2017		379.5	0.977	370.9	1,896,798	0.086	163,323
Oct	2017		379.5	0.694	263.5	1,896,798	0.079	149,613
Nov	2017		379.5	0.656	249.1	1,896,798	0.075	142,066
Dec	2017		379.5	0.687	260.8	1,896,798	0.079	149,887
Jan	2018		389.7	0.648	252.6	1,948,012	0.078	152,667
Feb	2018		389.7	0.645	251.4	1,948,012	0.071	138,141
Mar	2018		389.7	0.631	245.9	1,948,012	0.076	148,537
Apr	2018		389.7	0.687	267.8	1,948,012	0.073	142,289
May	2018		389.7	0.770	300.3	1,948,012	0.080	156,561
Jun	2018		389.7	0.966	376.5	1,948,012	0.091	177,569
Jul	2018		389.7	1.000	389.7	1,948,012	0.109	211,613
Aug	2018		389.7	0.984	383.6	1,948,012	0.102	199,411
Sep	2018		389.7	0.977	380.9	1,948,012	0.086	167,733
Oct	2018		389.7	0.694	270.6	1,948,012	0.079	153,653
Nov	2018		389.7	0.656	255.8	1,948,012	0.075	145,902
Dec	2018		389.7	0.687	267.8	1,948,012	0.079	153,934
Jan	2019		400.3	0.648	259.4	2,000,608	0.078	156,789
Feb	2019		400.3	0.645	258.2	2,000,608	0.071	141,871
Mar	2019		400.3	0.631	252.6	2,000,608	0.076	152,548
Apr	2019		400.3	0.687	275.1	2,000,608	0.073	146,131
May	2019		400.3	0.770	308.4	2,000,608	0.080	160,789
Jun	2019		400.3	0.966	386.7	2,000,608	0.091	182,363
Jul	2019		400.3	1.000	400.3	2,000,608	0.109	217,327
Aug	2019		400.3	0.984	394.0	2,000,608	0.102	204,795
Sep	2019		400.3	0.977	391.1	2,000,608	0.086	172,262
Oct	2019		400.3	0.694	277.9	2,000,608	0.079	157,802
Nov	2019		400.3	0.656	262.7	2,000,608	0.075	149,841
Dec	2019		400.3	0.687	275.0	2,000,608	0.079	158,091
Jan	2020		411.1	0.648	266.4	2,059,202	0.078	161,382
Feb	2020		411.1	0.645	265.2	2,059,202	0.071	146,026
Mar	2020		411.1	0.631	259.4	2,059,202	0.076	157,015
Apr	2020		411.1	0.687	282.5	2,059,202	0.073	150,411
May	2020		411.1	0.770	316.7	2,059,202	0.080	165,498
Jun	2020		411.1	0.966	397.1	2,059,202	0.091	187,704
Jul	2020		411.1	1.000	411.1	2,059,202	0.109	223,692
Aug	2020		411.1	0.984	404.6	2,059,202	0.102	210,793
Sep	2020		411.1	0.977	401.7	2,059,202	0.086	177,307
Oct	2020		411.1	0.694	285.4	2,059,202	0.079	162,423
Nov	2020		411.1	0.656	269.8	2,059,202	0.075	154,230
Dec	2020		411.1	0.687	282.5	2,059,202	0.079	162,721

Jan	2021		422.2	0.648	273.6	2,110,100	0.078	165,370
Feb	2021		422.2	0.645	272.3	2,110,100	0.071	149,636
Mar	2021		422.2	0.631	266.4	2,110,100	0.076	160,896
Apr	2021		422.2	0.687	290.1	2,110,100	0.073	154,129
May	2021		422.2	0.770	325.3	2,110,100	0.080	169,588
Jun	2021		422.2	0.966	407.9	2,110,100	0.091	192,343
Jul	2021		422.2	1.000	422.2	2,110,100	0.109	229,221
Aug	2021		422.2	0.984	415.6	2,110,100	0.102	216,003
Sep	2021		422.2	0.977	412.6	2,110,100	0.086	181,689
Oct	2021		422.2	0.694	293.2	2,110,100	0.079	166,438
Nov	2021		422.2	0.656	277.1	2,110,100	0.075	158,042
Dec	2021		422.2	0.687	290.1	2,110,100	0.079	166,743
Jan	2022		433.6	0.648	281.0	2,167,072	0.078	169,835
Feb	2022		433.6	0.645	279.7	2,167,072	0.071	153,676
Mar	2022		433.6	0.631	273.6	2,167,072	0.076	165,241
Apr	2022		433.6	0.687	298.0	2,167,072	0.073	158,290
May	2022		433.6	0.770	334.0	2,167,072	0.080	174,167
Jun	2022		433.6	0.966	418.9	2,167,072	0.091	197,537
Jul	2022		433.6	1.000	433.6	2,167,072	0.109	235,410
Aug	2022		433.6	0.984	426.8	2,167,072	0.102	221,835
Sep	2022		433.6	0.977	423.7	2,167,072	0.086	186,595
Oct	2022		433.6	0.694	301.1	2,167,072	0.079	170,932
Nov	2022		433.6	0.656	284.6	2,167,072	0.075	162,309
Dec	2022		433.6	0.687	297.9	2,167,072	0.079	171,245
Jan	2023		445.3	0.648	288.6	2,225,583	0.078	174,421
Feb	2023		445.3	0.645	287.2	2,225,583	0.071	157,825
Mar	2023		445.3	0.631	281.0	2,225,583	0.076	169,702
Apr	2023		445.3	0.687	306.0	2,225,583	0.073	162,564
May	2023		445.3	0.770	343.1	2,225,583	0.080	178,870
Jun	2023		445.3	0.966	430.2	2,225,583	0.091	202,870
Jul	2023		445.3	1.000	445.3	2,225,583	0.109	241,766
Aug	2023		445.3	0.984	438.3	2,225,583	0.102	227,825
Sep	2023		445.3	0.977	435.1	2,225,583	0.086	191,633
Oct	2023		445.3	0.694	309.2	2,225,583	0.079	175,547
Nov	2023		445.3	0.656	292.3	2,225,583	0.075	166,691
Dec	2023		445.3	0.687	306.0	2,225,583	0.079	175,868
Jan	2024		457.3	0.648	296.4	2,290,766	0.078	179,529
Feb	2024		457.3	0.645	295.0	2,290,766	0.071	162,447
Mar	2024		457.3	0.631	288.6	2,290,766	0.076	174,672
Apr	2024		457.3	0.687	314.3	2,290,766	0.073	167,325
May	2024		457.3	0.770	352.3	2,290,766	0.080	184,109
Jun	2024		457.3	0.966	441.8	2,290,766	0.091	208,812
Jul	2024		457.3	1.000	457.3	2,290,766	0.109	248,847
Aug	2024		457.3	0.984	450.1	2,290,766	0.102	234,497
Sep	2024		457.3	0.977	446.9	2,290,766	0.086	197,246
Oct	2024		457.3	0.694	317.5	2,290,766	0.079	180,688
Nov	2024		457.3	0.656	300.2	2,290,766	0.075	171,573
Dec	2024		457.3	0.687	314.2	2,290,766	0.079	181,019
Jan	2025		469.6	0.648	304.4	2,347,559	0.078	183,980
Feb	2025		469.6	0.645	302.9	2,347,559	0.071	166,475
Mar	2025		469.6	0.631	296.4	2,347,559	0.076	179,003
Apr	2025		469.6	0.687	322.7	2,347,559	0.073	171,474
May	2025		469.6	0.770	361.8	2,347,559	0.080	188,673
Jun	2025		469.6	0.966	453.7	2,347,559	0.091	213,989
Jul	2025		469.6	1.000	469.6	2,347,559	0.109	255,016
Aug	2025		469.6	0.984	462.3	2,347,559	0.102	240,311
Sep	2025		469.6	0.977	458.9	2,347,559	0.086	202,136
Oct	2025		469.6	0.694	326.1	2,347,559	0.079	185,168
Nov	2025		469.6	0.656	308.3	2,347,559	0.075	175,827
Dec	2025		469.6	0.687	322.7	2,347,559	0.079	185,507

Jan	2026		482.3	0.648	312.6	2,410,943	0.078	188,948
Feb	2026		482.3	0.645	311.1	2,410,943	0.071	170,970
Mar	2026		482.3	0.631	304.4	2,410,943	0.076	183,836
Apr	2026		482.3	0.687	331.5	2,410,943	0.073	176,103
May	2026		482.3	0.770	371.6	2,410,943	0.080	193,767
Jun	2026		482.3	0.966	466.0	2,410,943	0.091	219,766
Jul	2026		482.3	1.000	482.3	2,410,943	0.109	261,902
Aug	2026		482.3	0.984	474.8	2,410,943	0.102	246,799
Sep	2026		482.3	0.977	471.3	2,410,943	0.086	207,593
Oct	2026		482.3	0.694	334.9	2,410,943	0.079	190,168
Nov	2026		482.3	0.656	316.6	2,410,943	0.075	180,574
Dec	2026		482.3	0.687	331.4	2,410,943	0.079	190,516
Jan	2027		495.3	0.648	321.0	2,476,038	0.078	194,049
Feb	2027		495.3	0.645	319.5	2,476,038	0.071	175,586
Mar	2027		495.3	0.631	312.6	2,476,038	0.076	188,799
Apr	2027		495.3	0.687	340.4	2,476,038	0.073	180,858
May	2027		495.3	0.770	381.6	2,476,038	0.080	198,999
Jun	2027		495.3	0.966	478.6	2,476,038	0.091	225,700
Jul	2027		495.3	1.000	495.3	2,476,038	0.109	268,973
Aug	2027		495.3	0.984	487.6	2,476,038	0.102	253,463
Sep	2027		495.3	0.977	484.1	2,476,038	0.086	213,198
Oct	2027		495.3	0.694	344.0	2,476,038	0.079	195,302
Nov	2027		495.3	0.656	325.1	2,476,038	0.075	185,450
Dec	2027		495.3	0.687	340.4	2,476,038	0.079	195,660
Jan	2028		508.7	0.648	329.7	2,548,370	0.078	199,718
Feb	2028		508.7	0.645	328.1	2,548,370	0.071	180,715
Mar	2028		508.7	0.631	321.0	2,548,370	0.076	194,315
Apr	2028		508.7	0.687	349.6	2,548,370	0.073	186,142
May	2028		508.7	0.770	391.9	2,548,370	0.080	204,812
Jun	2028		508.7	0.966	491.5	2,548,370	0.091	232,294
Jul	2028		508.7	1.000	508.7	2,548,370	0.109	276,831
Aug	2028		508.7	0.984	500.8	2,548,370	0.102	260,867
Sep	2028		508.7	0.977	497.1	2,548,370	0.086	219,427
Oct	2028		508.7	0.694	353.3	2,548,370	0.079	201,007
Nov	2028		508.7	0.656	333.9	2,548,370	0.075	190,867
Dec	2028		508.7	0.687	349.6	2,548,370	0.079	201,375
Jan	2029		522.4	0.648	338.6	2,611,549	0.078	204,669
Feb	2029		522.4	0.645	337.0	2,611,549	0.071	185,195
Mar	2029		522.4	0.631	329.7	2,611,549	0.076	199,132
Apr	2029		522.4	0.687	359.0	2,611,549	0.073	190,756
May	2029		522.4	0.770	402.5	2,611,549	0.080	209,890
Jun	2029		522.4	0.966	504.7	2,611,549	0.091	238,052
Jul	2029		522.4	1.000	522.4	2,611,549	0.109	283,694
Aug	2029		522.4	0.984	514.3	2,611,549	0.102	267,335
Sep	2029		522.4	0.977	510.6	2,611,549	0.086	224,867
Oct	2029		522.4	0.694	362.8	2,611,549	0.079	205,991
Nov	2029		522.4	0.656	342.9	2,611,549	0.075	195,599
Dec	2029		522.4	0.687	359.0	2,611,549	0.079	206,368
Jan	2030		536.6	0.648	347.7	2,682,061	0.078	210,196
Feb	2030		536.6	0.645	346.1	2,682,061	0.071	190,196
Mar	2030		536.6	0.631	338.6	2,682,061	0.076	204,509
Apr	2030		536.6	0.687	368.7	2,682,061	0.073	195,907
May	2030		536.6	0.770	413.4	2,682,061	0.080	215,557
Jun	2030		536.6	0.966	518.4	2,682,061	0.091	244,480
Jul	2030		536.6	1.000	536.6	2,682,061	0.109	291,354
Aug	2030		536.6	0.984	528.2	2,682,061	0.102	274,553
Sep	2030		536.6	0.977	524.3	2,682,061	0.086	230,938
Oct	2030		536.6	0.694	372.6	2,682,061	0.079	211,553
Nov	2030		536.6	0.656	352.2	2,682,061	0.075	200,881
Dec	2030		536.6	0.687	368.7	2,682,061	0.079	211,940

Appendix II-Resource Operating Information and Other Modeling Assumptions

General Assumptions

✓ 15-year Net Present Value of incremental production expenses:
January 2016 to December 2030 time frame, NPV in 2015 dollars

Financial Assumptions

✓ Interest Rate: 5.0% / 6.5% / 8.0% (min / likely / max)
✓ Financing Period: 30 Years
✓ Inflation Rate: 1.5% / 2.5% / 3.5% (min / likely / max)
✓ Discount Rate: 8.0%

Existing Resource Assumptions

Hydro Units:

✓ 2.68 MW capacity
✓ $0.98/MWh VO&M cost (2006$)
✓ Dispatched first after CROD up to maximum capacity each hour

Silver Lake Plant:

✓ 45 MW or 92 MW capacity
✓ Unit 4 assumed to be only unit to dispatch
✓ 10,500 Btu/kWh heat rate
✓ $1.88/MMBtu fuel cost (2004$) from EIA data for reported fuel receipts at plant
✓ $6.17/MWh VO&M cost (2006$) from O&M allocation file provided by RPU, escalating at 2.5% per year
✓ $4.3 million in 2006 to $6.0 million in 2030 total capital and FO&M for Unit 4

Existing TwinPac CT:

✓ 49 MW capacity
✓ 11,100 Btu/kWh heat rate, assumed at 80% average load based on info from RPU
✓ $3.89/MWh VO&M cost (2006$) from O&M allocation file provided by RPU, escalating at 2.5% per year
✓ No fixed costs (debt service, fixed O&M, etc.) included

New Resource Assumptions

New Coal Unit Purchase:

✓ 500 MW total capacity
✓ 9,622 Btu/kWh heat rate, PRB fuel
✓ $1,958/kW for 2015 online date - $149/kW-yr debt service cost
✓ $2.09/MWh VO&M cost (2004$)
✓ $20.47/kW-yr FO&M (2004$)
✓ 0.11 lb/MMBtu SO_2 at $1,122/ton, no escalation
✓ 0.05 lb/MMBtu NO_X at $1,491/ton, no escalation
✓ $3.732/kW-mo transmission cost for new unit, no escalation

New Combined Cycle Unit Purchase:
- ✓ 125 MW total capacity
- ✓ 7,763 Btu/kWh heat rate
- ✓ $1,136/kW for 2015 online date - $87/kW-yr debt service cost
- ✓ $2.81/MWh VO&M cost (2004$)
- ✓ $14.02/kW-yr FO&M (2004$)

New LMS100 High-Efficiency Combustion Turbine:
- ✓ 100 MW total capacity
- ✓ 9,379 Btu/kWh heat rate
- ✓ $629/kW for 2020 online date - $48/kW-yr debt service cost
- ✓ $3.30/MWh VO&M cost (2004$)

New FT8 TwinPac Combustion Turbines:
- ✓ 50 MW total capacity
- ✓ 11,100 Btu/kWh heat rate
- ✓ $789/kW for 2015 online date - $60/kW-yr debt service cost
- ✓ $3.89/MWh VO&M cost (2004$)
- ✓ $11.44/kW-mo FO&M cost (2004$)

On-Peak Non-Firm Market Energy:
- ✓ Historical Henry Hub natural gas prices used to calculate an implied heat rate for each day of historical MAIN market peak prices (2001-2003)
- ✓ Monthly implied heat rates used to calculate market price based on current monthly gas price:

Jan	8,300 Btu/kWh	Jul	11,400 Btu/kWh
Feb	7,590 Btu/kWh	Aug	9,870 Btu/kWh
Mar	8,300 Btu/kWh	Sep	6,970 Btu/kWh
Apr	7,590 Btu/kWh	Oct	6,860 Btu/kWh
May	5,810 Btu/kWh	Nov	7,170 Btu/kWh
Jun	6,480 Btu/kWh	Dec	6,260 Btu/kWh

Load Forecast

Year	MW	GWh
2016	369.5	1,851
2017	379.5	1,897
2018	389.7	1,948
2019	400.3	2,001
2020	411.1	2,059
2021	422.2	2,110
2022	433.6	2,167
2023	445.3	2,226
2024	457.3	2,291
2025	469.6	2,348

2026	482.3	2,411
2027	495.3	2,476
2028	508.7	2,548
2029	522.4	2,612
2030	536.6	2,682

✓ Monthly pattern applied to annual peak demand and total energy:

Month	Ratio to Annual Peak	Ratio to Annual Total Energy
Jan	0.648	0.0784
Feb	0.645	0.0709
Mar	0.631	0.0763
Apr	0.687	0.0730
May	0.770	0.0804
Jun	0.966	0.0912
Jul	1.000	0.1086
Aug	0.984	0.1024
Sep	0.977	0.0861
Oct	0.694	0.0789
Nov	0.656	0.0749
Dec	0.687	0.0790

Fuel Assumptions

Year	Henry Hub ($/MMBtu)	Gas Trans. ($/MMBtu)	PRB Coal, Minemouth ($/MMBtu)	PRB Coal Transportation ($/MMBtu)	FO#2 ($/MMBtu)
2016	7.39	0.54	0.58	0.83	6.96
2017	7.65	0.55	0.59	0.85	7.14
2018	7.92	0.56	0.61	0.87	7.31
2019	8.20	0.58	0.63	0.90	7.50
2020	8.49	0.59	0.65	0.92	7.69
2021	8.78	0.61	0.67	0.94	7.88
2022	9.09	0.62	0.69	0.97	8.07
2023	9.41	0.64	0.71	0.99	8.28
2024	9.75	0.66	0.73	1.01	8.48
2025	10.09	0.67	0.75	1.04	8.70
2026	10.45	0.69	0.77	1.07	8.91
2027	10.81	0.71	0.80	1.09	9.14
2028	11.19	0.72	0.82	1.12	9.36
2029	11.59	0.74	0.85	1.15	9.60
2030	12.00	0.76	0.87	1.18	9.84

✓ Monthly pattern applied to annual average natural gas price:

Month	Ratio to Annual Average
Jan	1.088
Feb	1.079
Mar	1.049
Apr	0.968
May	0.959
Jun	0.961
Jul	0.965
Aug	0.968
Sep	0.966
Oct	0.969
Nov	0.999
Dec	1.031

Case Assumptions

	Existing Capacity			Capacity Added - MW(year)				
Case	**CROD**	**Other**	**SLP**	**Coal**	**Combined Cycle**	**Twin Pac**		
None216-100Coal	216	51	0	100(15)		50(15)	50(20)	50(25)
None216-50Coal	216	51	0	50(15)		100(15)	50(20)	50(25)
None216-100CC	216	51	0		100(15)	50(15)	50(20)	50(25)
None216-LMS100	216	51	0		100(15)	50(15)	50(20)	50(25)
None216-SC	216	51	0			150(15)	50(20)	50(25)
45216-50Coal_CoalFirst	216	51	45	50(15)		50(15)	50(20)	50(25)
45216-50Coal_SLPfirst	216	51	45	50(15)		50(15)	50(20)	50(25)
45216-100CC	216	51	45		100(15)		50(20)	50(25)
45216-LMS100	216	51	45		100(15)		50(20)	50(25)
45216-SC	216	51	45			100(15)	50(20)	50(25)
All216-50Coal_CoalFirst	216	51	92	50(15)			50(20)	50(25)
All216-50Coal_SLPfirst	216	51	92	50(15)			50(20)	50(25)
All216-100CC	216	51	92		100(20)	50(20)		
All216-LMS100	216	51	92		100(20)	50(20)		
All216-SC	216	51	92			50(15)	50(20)	50(25)

None, 45, All refers to amount of Silver Lake Plant available
166 or 216 refers to CROD amount
MWCoal refers to amount of coal capacity added in case
MWCC refers to combined cycle added in case
SC refers to only simple cycle TwinPac units added

Appendix III – Production Cost Analysis Details

Financial Analysis
None216-100CC

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New CC	74	85	93	102	110	115	122	128	135	142	150	158	166	175	183
Existing CT	0	1	4	8	0	4	8	16	27	11	24	42	60	84	113
New CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4
On-Peak Market Energy	47	60	78	100	138	170	203	236	266	326	359	389	422	449	473
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
New CC	$4,708	$5,576	$6,329	$7,202	$8,060	$8,802	$9,620	$10,516	$11,496	$12,567	$13,727	$14,993	$16,372	$17,884	$19,340
Existing CT	$0	$68	$402	$780	$0	$418	$915	$1,781	$3,200	$1,322	$3,038	$5,445	$8,096	$11,754	$16,245
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$628
On-Peak Market Energy	$2,405	$3,182	$4,488	$6,141	$8,913	$11,594	$14,584	$17,738	$20,886	$26,505	$30,259	$33,893	$37,940	$41,621	$45,289
Total Variable Costs	$7,125	$8,840	$11,237	$14,143	$16,996	$20,839	$25,145	$30,061	$35,611	$40,425	$47,056	$54,364	$62,444	$71,296	$81,541
DEMAND/FIXED COST ($000)															
New CC	$14,591	$14,650	$14,710	$14,772	$14,836	$14,901	$14,968	$15,036	$15,106	$15,178	$15,251	$15,327	$15,404	$15,483	$15,564
New CT	$3,776	$3,795	$3,815	$3,835	$8,106	$8,149	$8,192	$8,237	$8,282	$13,138	$13,210	$13,284	$13,360	$13,438	$13,517
Total Fixed Costs	$18,367	$18,445	$18,525	$18,607	$22,942	$23,049	$23,160	$23,273	$23,388	$28,316	$28,462	$28,611	$28,764	$28,921	$29,082
TOTAL COST	**$25,492**	**$27,285**	**$29,762**	**$32,750**	**$39,938**	**$43,888**	**$48,304**	**$53,334**	**$59,000**	**$68,741**	**$75,517**	**$82,975**	**$91,208**	**$100,217**	**$110,623**

15-Year NPV (2015 $000): $435,755

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP															
New CC	$260.22	$238.60	$226.79	$216.02	$208.72	$205.38	$202.32	$199.60	$197.22	$195.19	$193.58	$192.31	$191.38	$190.74	$191.16
Existing CT		$93.03	$96.19	$99.46		$106.34	$109.96	$113.79	$117.75	$121.58	$125.89	$130.26	$134.73	$139.38	$144.21
New CT															$3,240.01
On-Peak Market Energy	$50.92	$53.02	$57.49	$61.45	$64.52	$68.32	$71.83	$75.28	$78.41	$81.23	$84.30	$87.09	$89.98	$92.67	$95.74

Financial Analysis

45216-LMS100-50Coal

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
New Coal	0	0	0	0	169	195	222	249	273	292	308	320	331	340	349
SLP	87	99	116	134	65	71	78	86	97	111	130	153	180	206	228
LMS100	21	26	31	36	12	17	22	27	32	38	44	51	57	64	72
CTs	0	3	7	12	0	0	0	2	6	0	4	10	17	29	41
New CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
On-Peak Market Energy	13	17	21	28	2	5	10	16	20	38	47	55	63	70	83
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
New Coal	$0	$0	$0	$0	$3,230	$3,831	$4,472	$5,130	$5,771	$6,341	$6,846	$7,298	$7,742	$8,160	$8,605
SLP	$3,147	$3,697	$4,440	$5,277	$2,635	$2,974	$3,365	$3,782	$4,401	$5,208	$6,256	$7,586	$9,146	$10,794	$12,273
LMS100	$1,628	$2,048	$2,513	$3,033	$1,076	$1,526	$2,028	$2,591	$3,222	$3,925	$4,705	$5,573	$6,534	$7,588	$8,747
CTs	$0	$274	$687	$1,191	$0	$0	$0	$206	$769	$0	$537	$1,275	$2,343	$3,992	$5,877
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
On-Peak Market Energy	$935	$1,212	$1,460	$1,883	$139	$492	$938	$1,427	$1,714	$3,380	$4,184	$4,978	$5,734	$6,471	$7,817
Total Variable Costs	$5,721	$7,245	$9,118	$11,404	$7,103	$8,847	$10,829	$13,163	$15,906	$18,884	$22,561	$26,742	$31,534	$37,041	$43,358
DEMAND/FIXED COST ($000)															
New Coal (Including Transmission)	$0	$0	$0	$0	$12,196	$12,234	$12,273	$12,312	$12,353	$12,395	$12,438	$12,482	$12,527	$12,574	$12,621
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
LMS100	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,809	$4,833	$4,858	$4,883	$4,909	$4,935
Total Fixed Costs	$9,693	$9,764	$9,835	$9,909	$22,180	$22,296	$22,414	$22,535	$22,660	$27,596	$27,751	$27,909	$28,072	$28,238	$28,409
TOTAL COST	**$15,415**	**$17,009**	**$18,954**	**$21,314**	**$29,283**	**$31,143**	**$33,243**	**$35,699**	**$38,566**	**$46,480**	**$50,311**	**$54,651**	**$59,605**	**$65,279**	**$71,767**

15-Year NPV (2015 $000): $288,674

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
New Coal					$91.36	$82.25	$75.31	$70.14	$66.44	$64.11	$62.68	$61.86	$61.28	$61.01	$60.75
SLP	$92.43	$87.20	$81.74	$77.56	$120.36	$115.58	$111.12	$107.55	$102.35	$97.01	$91.84	$87.20	$83.63	$81.38	$80.58
LMS100	$300.87	$263.49	$237.07	$217.60	$475.65	$373.33	$313.56	$274.74	$247.96	$228.97	$215.19	$205.05	$197.62	$192.36	$188.72
Existing CT		$93.62	$96.80	$100.07				$114.43	$118.33		$126.53	$130.84	$135.21	$139.70	$144.40
New CT															
On-Peak Market Energy	$72.05	$70.46	$69.33	$68.23	$86.89	$89.90	$90.59	$87.75	$86.04	$89.98	$89.72	$89.97	$91.27	$92.86	$93.86

Financial Analysis
45216-LMS100

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	87	99	116	134	155	178	202	223	233	237	237	237	237	237	237
LMS100	21	26	31	36	41	47	53	59	66	72	74	74	74	74	74
CTs	0	3	7	12	4	9	15	25	35	22	33	47	64	75	87
On-Peak Market Energy	13	17	21	28	48	56	64	72	94	149	189	231	272	314	360
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$3,147	$3,697	$4,440	$5,277	$6,273	$7,405	$8,648	$9,859	$10,603	$11,055	$11,376	$11,707	$12,047	$12,397	$12,757
LMS100	$1,628	$2,048	$2,513	$3,033	$3,610	$4,244	$4,942	$5,708	$6,543	$7,451	$7,934	$8,204	$8,484	$8,773	$9,072
CTs	$0	$274	$687	$1,191	$389	$922	$1,615	$2,805	$4,135	$2,639	$4,171	$6,158	$8,638	$10,533	$12,616
On-Peak Market Energy	$935	$1,212	$1,460	$1,883	$3,486	$4,087	$4,727	$5,424	$7,218	$11,889	$15,721	$20,077	$24,733	$29,758	$35,398
Total Variable Costs	$5,721	$7,245	$9,118	$11,404	$13,780	$16,682	$19,957	$23,823	$28,528	$33,064	$39,234	$46,179	$54,041	$62,558	$71,991
DEMAND/FIXED COST ($000)															
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
LMS100	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790
New CT	$0	$0	$0	$0	$4,251	$4,272	$4,294	$4,316	$4,339	$9,171	$9,219	$9,269	$9,319	$9,371	$9,424
Total Fixed Costs	$9,693	$9,764	$9,835	$9,909	$14,235	$14,334	$14,435	$14,539	$14,645	$19,563	$19,699	$19,838	$19,980	$20,126	$20,276
TOTAL COST	**$15,415**	**$17,009**	**$18,954**	**$21,314**	**$28,016**	**$31,016**	**$34,392**	**$38,362**	**$43,173**	**$52,627**	**$58,932**	**$66,017**	**$74,022**	**$82,684**	**$92,267**

15-Year NPV (2015 $000): $320,892

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP	$92.43	$87.20	$81.74	$77.56	$74.05	$71.36	$69.44	$68.46	$69.05	$70.42	$72.15	$73.93	$75.76	$77.64	$79.57
LMS100	$300.87	$263.49	$237.07	$217.60	$202.97	$191.99	$183.67	$177.37	$172.73	$169.41	$171.02	$174.65	$178.41	$182.30	$186.32
Existing CT		$93.62	$96.80	$100.07	$103.50	$107.02	$110.62	$114.27	$118.10	$122.23	$126.31	$130.58	$135.00	$139.56	$144.29
New CT													$12,062.71	$1,377.23	$791.61
On-Peak Market Energy	$72.05	$70.46	$69.33	$68.23	$72.87	$73.33	$74.21	$75.13	$76.49	$79.82	$83.26	$87.08	$90.90	$94.64	$98.40

Financial Analysis

45216-50coal (Dispatch New Coal First)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
New Coal	86	101	120	143	169	195	222	249	273	292	308	320	331	340	349
SLP	31	37	42	48	54	60	68	77	90	108	130	157	185	212	236
CTs	0	0	0	0	0	0	0	0	0	0	0	0	1	7	13
On-Peak Market Energy	4	8	12	18	25	33	43	54	66	79	95	112	132	150	174
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
New Coal	$1,484	$1,790	$2,189	$2,676	$3,230	$3,831	$4,472	$5,130	$5,771	$6,341	$6,846	$7,298	$7,742	$8,160	$8,605
SLP	$1,127	$1,371	$1,625	$1,893	$2,184	$2,517	$2,903	$3,401	$4,092	$5,042	$6,274	$7,752	$9,400	$11,097	$12,721
CTs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$78	$924	$1,884
On-Peak Market Energy	$347	$613	$994	$1,511	$2,167	$2,964	$3,916	$5,030	$6,331	$7,854	$9,635	$11,722	$14,102	$16,278	$19,135
Total Variable Costs	$2,969	$3,789	$4,827	$6,100	$7,603	$9,337	$11,317	$13,588	$16,222	$19,267	$22,787	$26,805	$31,358	$36,497	$42,385
DEMAND/FIXED COST ($000)															
New Coal (Including Transmission)	$11,202	$11,237	$11,272	$11,308	$11,345	$11,383	$11,422	$11,462	$11,503	$11,545	$11,588	$11,632	$11,677	$11,723	$11,771
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
New CT	$3,828	$3,847	$3,867	$3,887	$8,217	$8,260	$8,303	$8,348	$8,394	$13,317	$13,389	$13,462	$13,538	$13,616	$13,695
Total Fixed Costs	$19,934	$20,057	$20,184	$20,314	$24,757	$24,915	$25,077	$25,243	$25,413	$30,463	$30,666	$30,873	$31,086	$31,305	$31,528
TOTAL COST	**$22,903**	**$23,847**	**$25,011**	**$26,414**	**$32,361**	**$34,252**	**$36,394**	**$38,831**	**$41,635**	**$49,730**	**$53,453**	**$57,678**	**$62,444**	**$67,801**	**$73,914**

15-Year NPV (2015 $000): $325,782

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
New Coal	$147.97	$129.13	$111.87	$97.50	$86.32	$77.90	$71.49	$66.72	$63.32	$61.20	$59.91	$59.20	$58.71	$58.50	$58.32
SLP	$193.40	$172.05	$157.02	$145.85	$136.87	$129.00	$121.97	$114.64	$106.66	$98.67	$91.71	$86.40	$82.75	$80.59	$79.64
Existing CT													$134.92	$139.53	$144.29
New CT															
On-Peak Market Energy	$77.33	$79.12	$81.49	$83.93	$86.39	$88.87	$91.36	$93.92	$96.57	$99.20	$101.82	$104.42	$106.93	$108.38	$109.76

Financial Analysis

45216-50Coal (Dispatch SLP First)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
New Coal	80	95	114	136	160	186	211	234	255	270	282	292	301	309	317
SLP	37	43	49	56	63	70	79	91	108	130	156	185	214	242	268
CTs	0	0	0	0	0	0	0	0	0	0	0	0	1	7	13
On-Peak Market Energy	4	8	12	18	25	33	43	54	66	79	95	112	132	150	174
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
New Coal	$1,389	$1,682	$2,066	$2,534	$3,065	$3,641	$4,242	$4,833	$5,385	$5,858	$6,275	$6,658	$7,051	$7,422	$7,820
SLP	$1,325	$1,597	$1,885	$2,192	$2,532	$2,920	$3,395	$4,035	$4,921	$6,082	$7,509	$9,138	$10,904	$12,708	$14,442
CTs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$78	$924	$1,884
On-Peak Market Energy	$347	$613	$994	$1,511	$2,167	$2,964	$3,916	$5,030	$6,331	$7,854	$9,635	$11,722	$14,102	$16,278	$19,136
Total Variable Costs	$3,073	$3,908	$4,963	$6,257	$7,787	$9,550	$11,578	$13,926	$16,665	$19,825	$23,451	$27,552	$32,171	$37,370	$43,321
DEMAND/FIXED COST ($000)															
New Coal (Including Transmission)	$11,202	$11,237	$11,272	$11,308	$11,345	$11,383	$11,422	$11,462	$11,503	$11,545	$11,588	$11,632	$11,677	$11,723	$11,771
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
New CT	$3,828	$3,847	$3,867	$3,887	$8,217	$8,260	$8,303	$8,348	$8,394	$13,317	$13,389	$13,462	$13,538	$13,616	$13,695
Total Fixed Costs	$19,934	$20,057	$20,184	$20,314	$24,757	$24,915	$25,077	$25,243	$25,413	$30,463	$30,666	$30,873	$31,086	$31,305	$31,528
TOTAL COST	**$23,007**	**$23,965**	**$25,147**	**$26,572**	**$32,545**	**$34,465**	**$36,655**	**$39,169**	**$42,078**	**$50,288**	**$54,116**	**$58,426**	**$63,257**	**$68,674**	**$74,849**

15-Year NPV (2015 $000): $328,750

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
New Coal	$156.92	$136.27	$117.47	$101.92	$89.93	$80.94	$74.28	$69.55	$66.35	$64.45	$63.34	$62.69	$62.18	$61.94	$61.70
SLP	$169.82	$152.96	$140.65	$131.29	$123.60	$116.94	$110.51	$103.57	$96.34	$89.79	$84.54	$80.80	$78.36	$77.02	$76.58
Existing CT													$134.92	$139.53	$144.29
New CT															
On-Peak Market Energy	$77.33	$79.12	$81.49	$83.93	$86.39	$88.87	$91.36	$93.92	$96.57	$99.20	$101.82	$104.42	$106.93	$108.38	$109.76

Financial Analysis
All216-50coal (Dispatch New Coal Unit First)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
New Coal	86	101	120	143	169	195	222	249	273	292	308	320	331	340	349
SLP	31	37	42	48	54	60	68	77	90	108	130	157	185	212	236
CTs	0	0	0	0	0	0	0	0	4	0	2	7	13	22	34
On-Peak Market Energy	4	8	12	18	25	33	43	54	61	79	93	105	119	135	153
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
New Coal	$1,484	$1,790	$2,189	$2,676	$3,230	$3,831	$4,472	$5,130	$5,771	$6,341	$6,846	$7,298	$7,742	$8,160	$8,605
SLP	$1,127	$1,371	$1,625	$1,893	$2,184	$2,517	$2,903	$3,401	$4,092	$5,042	$6,274	$7,752	$9,400	$11,097	$12,721
CTs	$0	$0	$0	$0	$0	$0	$0	$0	$524	$0	$237	$951	$1,751	$3,095	$4,930
On-Peak Market Energy	$347	$613	$994	$1,511	$2,167	$2,964	$3,916	$5,030	$5,822	$7,854	$9,404	$10,797	$12,473	$14,222	$16,332
Total Variable Costs	$2,969	$3,789	$4,827	$6,100	$7,603	$9,337	$11,317	$13,588	$16,237	$19,267	$22,794	$26,831	$31,402	$36,611	$42,628
DEMAND/FIXED COST ($000)															
New Coal (Including Transmission)	$11,202	$11,237	$11,272	$11,308	$11,345	$11,383	$11,422	$11,462	$11,503	$11,545	$11,588	$11,632	$11,677	$11,723	$11,771
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
SLP (Unit 1-3 FO&M)	$3,547	$3,636	$3,727	$3,820	$3,915	$4,013	$4,114	$4,216	$4,322	$4,430	$4,541	$4,654	$4,771	$4,890	$5,012
New CT	$0	$0	$0	$0	$4,310	$4,331	$4,353	$4,375	$4,398	$9,297	$9,345	$9,394	$9,445	$9,497	$9,550
Total Fixed Costs	$19,653	$19,846	$20,044	$20,247	$24,765	$25,000	$25,240	$25,486	$25,739	$30,874	$31,163	$31,460	$31,764	$32,075	$32,395
TOTAL COST	**$22,622**	**$23,636**	**$24,871**	**$26,347**	**$32,368**	**$34,336**	**$36,557**	**$39,074**	**$41,976**	**$50,141**	**$53,957**	**$58,290**	**$63,166**	**$68,686**	**$75,022**

15-Year NPV (2015 $000): $327,201

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
New Coal	$147.97	$129.13	$111.87	$97.50	$86.32	$77.90	$71.49	$66.72	$63.32	$61.20	$59.91	$59.20	$58.71	$58.50	$58.32
SLP	$193.40	$172.05	$157.02	$145.85	$136.87	$129.00	$121.97	$114.64	$106.66	$98.67	$91.71	$86.40	$82.75	$80.59	$79.64
Existing CT									$118.00		$126.17	$130.47	$134.92	$139.58	$144.39
New CT															
On-Peak Market Energy	$77.33	$79.12	$81.49	$83.93	$86.39	$88.87	$91.36	$93.92	$95.26	$99.20	$101.39	$102.86	$104.40	$105.62	$106.56

Financial Analysis

None216-50Coal

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
New Coal	86	101	120	143	169	195	222	249	273	292	308	320	331	340	349
SLP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTs	0	0	0	0	0	0	0	0	3	0	2	9	16	27	41
On-Peak Market Energy	36	45	55	66	79	94	111	131	153	187	223	260	301	341	382
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
New Coal	$1,484	$1,790	$2,189	$2,676	$3,230	$3,831	$4,472	$5,130	$5,771	$6,341	$6,846	$7,298	$7,742	$8,160	$8,605
SLP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CTs	$0	$0	$0	$0	$0	$0	$0	$0	$360	$0	$310	$1,158	$2,110	$3,789	$5,902
On-Peak Market Energy	$2,662	$3,423	$4,313	$5,355	$6,571	$7,998	$9,669	$11,696	$13,893	$17,473	$21,177	$25,126	$29,676	$34,267	$39,181
Total Variable Costs	$4,157	$5,229	$6,521	$8,051	$9,824	$11,853	$14,167	$16,853	$20,052	$23,844	$28,365	$33,615	$39,564	$46,254	$53,727
DEMAND/FIXED COST ($000)															
New Coal (Including Transmission)	$11,073	$11,107	$11,142	$11,179	$11,216	$11,254	$11,293	$11,333	$11,373	$11,415	$11,458	$11,502	$11,548	$11,594	$11,641
New CT	$7,551	$7,590	$7,629	$7,670	$11,962	$12,025	$12,091	$12,157	$12,226	$17,105	$17,202	$17,300	$17,401	$17,504	$17,610
Total Fixed Costs	$18,624	$18,697	$18,772	$18,848	$23,177	$23,279	$23,383	$23,490	$23,599	$28,521	$28,660	$28,802	$28,948	$29,098	$29,252
TOTAL COST	**$22,781**	**$23,926**	**$25,292**	**$26,899**	**$33,001**	**$35,132**	**$37,551**	**$40,343**	**$43,651**	**$52,365**	**$57,025**	**$62,418**	**$68,512**	**$75,352**	**$82,979**
15-Year NPV (2015 $000):	**$342,102**														
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
New Coal	$146.46	$127.85	$110.79	$96.60	$85.55	$77.23	$70.91	$66.20	$62.85	$60.75	$59.49	$58.79	$58.32	$58.12	$57.95
Existing CT									$118.00		$126.17	$130.47	$134.92	$139.59	$144.39
New CT															
On-Peak Market Energy	$74.62	$76.71	$78.88	$81.04	$83.19	$85.32	$87.47	$89.55	$91.05	$93.41	$95.13	$96.64	$98.47	$100.38	$102.46

Financial Analysis

All216-50coal (Dispatch SLP First)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
New Coal	80	95	114	136	160	186	211	234	255	270	282	292	301	309	317
SLP	37	43	49	56	63	70	79	91	108	130	156	185	214	242	268
CTs	0	0	0	0	0	0	0	0	4	0	2	7	13	22	34
On-Peak Market Energy	4	8	12	18	25	33	43	54	61	79	93	105	119	135	153
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
New Coal	$1,389	$1,682	$2,066	$2,534	$3,065	$3,641	$4,242	$4,833	$5,385	$5,858	$6,275	$6,658	$7,051	$7,422	$7,820
SLP	$1,325	$1,597	$1,885	$2,192	$2,532	$2,920	$3,395	$4,035	$4,921	$6,082	$7,509	$9,138	$10,904	$12,708	$14,442
CTs	$0	$0	$0	$0	$0	$0	$0	$0	$524	$0	$237	$951	$1,751	$3,095	$4,930
On-Peak Market Energy	$347	$613	$994	$1,511	$2,167	$2,964	$3,916	$5,030	$5,822	$7,854	$9,404	$10,797	$12,473	$14,222	$16,333
Total Variable Costs	$3,073	$3,908	$4,963	$6,257	$7,787	$9,550	$11,578	$13,926	$16,680	$19,825	$23,457	$27,578	$32,215	$37,484	$43,563
DEMAND/FIXED COST ($000)															
New Coal (Including Transmission)	$11,202	$11,237	$11,272	$11,308	$11,345	$11,383	$11,422	$11,462	$11,503	$11,545	$11,588	$11,632	$11,677	$11,723	$11,771
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
SLP (Unit 1-3 FO&M)	$3,547	$3,636	$3,727	$3,820	$3,915	$4,013	$4,114	$4,216	$4,322	$4,430	$4,541	$4,654	$4,771	$4,890	$5,012
New CT	$0	$0	$0	$0	$4,310	$4,331	$4,353	$4,375	$4,398	$9,297	$9,345	$9,394	$9,445	$9,497	$9,550
Total Fixed Costs	$19,653	$19,846	$20,044	$20,247	$24,765	$25,000	$25,240	$25,486	$25,739	$30,874	$31,163	$31,460	$31,764	$32,075	$32,395
TOTAL COST	**$22,726**	**$23,754**	**$25,007**	**$26,505**	**$32,552**	**$34,550**	**$36,818**	**$39,412**	**$42,419**	**$50,698**	**$54,620**	**$59,038**	**$63,979**	**$69,559**	**$75,958**

15-Year NPV (2015 $000): $330,169

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
New Coal	$156.92	$136.27	$117.47	$101.92	$89.93	$80.94	$74.28	$69.55	$66.35	$64.45	$63.34	$62.69	$62.18	$61.94	$61.70
SLP	$169.82	$152.96	$140.65	$131.29	$123.60	$116.94	$110.51	$103.57	$96.34	$89.79	$84.54	$80.80	$78.36	$77.02	$76.58
Existing CT									$118.00		$126.17	$130.47	$134.92	$139.58	$144.39
New CT															
On-Peak Market Energy	$77.33	$79.12	$81.49	$83.93	$86.39	$88.87	$91.36	$93.92	$95.26	$99.20	$101.39	$102.86	$104.40	$105.62	$106.56

Financial Analysis

All216-LMS100

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	87	99	116	134	155	178	202	223	233	237	237	237	237	237	237
LMS100	0	0	0	0	41	47	53	59	66	72	74	74	74	74	74
Existing CT	0	1	6	11	4	9	15	25	35	50	66	77	88	104	141
New CT	0	0	0	0	0	0	0	0	0	0	0	7	13	23	36
On-Peak Market Energy	34	45	53	64	48	56	64	72	94	120	155	194	236	271	285
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$3,147	$3,697	$4,440	$5,277	$6,273	$7,405	$8,648	$9,859	$10,603	$11,055	$11,376	$11,707	$12,047	$12,397	$12,757
LMS100	$0	$0	$0	$0	$3,610	$4,244	$4,942	$5,708	$6,543	$7,451	$7,934	$8,204	$8,484	$8,773	$9,072
Existing CT	$0	$131	$604	$1,138	$389	$922	$1,615	$2,805	$4,135	$6,141	$8,376	$10,043	$11,872	$14,526	$20,483
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$30	$864	$1,783	$3,171	$5,185
On-Peak Market Energy	$2,799	$3,660	$4,332	$5,246	$3,486	$4,087	$4,727	$5,424	$7,218	$9,493	$12,878	$16,915	$21,461	$25,729	$28,072
Total Variable Costs	$5,957	$7,503	$9,393	$11,681	$13,780	$16,682	$19,957	$23,823	$28,528	$34,171	$40,625	$47,767	$55,682	$64,632	$75,609
DEMAND/FIXED COST ($000)															
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
SLP (Unit 1-3 FO&M)	$3,547	$3,636	$3,727	$3,820	$3,915	$4,013	$4,114	$4,216	$4,322	$4,430	$4,541	$4,654	$4,771	$4,890	$5,012
LMS100	$0	$0	$0	$0	$5,109	$5,109	$5,109	$5,109	$5,109	$5,109	$5,109	$5,109	$5,109	$5,109	$5,109
New CT	$3,976	$3,995	$4,015	$4,035	$4,056	$4,077	$4,099	$4,121	$4,144	$4,168	$4,192	$4,216	$4,241	$4,267	$4,294
Total Fixed Costs	$12,427	$12,605	$12,787	$12,974	$18,275	$18,472	$18,673	$18,880	$19,092	$19,308	$19,531	$19,759	$19,992	$20,232	$20,477
TOTAL COST	**$18,384**	**$20,107**	**$22,181**	**$24,656**	**$32,056**	**$35,154**	**$38,630**	**$42,703**	**$47,619**	**$53,479**	**$60,156**	**$67,526**	**$75,674**	**$84,864**	**$96,086**

15-Year NPV (2015 $000): $347,789

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP	$92.43	$87.20	$81.74	$77.56	$74.05	$71.36	$69.44	$68.46	$69.05	$70.42	$72.15	$73.93	$75.76	$77.64	$79.57
LMS100					$210.69	$198.77	$189.69	$182.77	$177.60	$173.83	$175.31	$178.94	$182.70	$186.59	$190.61
Existing CT		$93.36	$96.53	$99.82	$103.50	$107.02	$110.62	$114.27	$118.10	$122.10	$126.24	$130.51	$134.93	$139.51	$145.41
New CT											$17,836.07	$769.03	$457.07	$327.97	$264.09
On-Peak Market Energy	$81.57	$81.93	$82.18	$81.90	$72.87	$73.33	$74.21	$75.13	$76.49	$78.95	$82.95	$87.12	$91.06	$95.05	$98.50

Financial Analysis

45216-SC

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	87	99	116	134	155	178	202	223	233	237	237	237	237	237	237
Existing CT	0	0	0	0	0	0	4	10	16	11	17	30	44	58	71
New CT	0	0	0	0	0	0	0	0	0	0	0	0	0	3	10
On-Peak Market Energy	34	46	59	75	93	111	128	146	179	232	279	322	367	412	455
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$3,147	$3,697	$4,440	$5,277	$6,273	$7,405	$8,648	$9,859	$10,603	$11,055	$11,376	$11,707	$12,047	$12,397	$12,757
Existing CT	$0	$0	$0	$0	$0	$0	$401	$1,122	$1,919	$1,282	$2,192	$3,955	$5,960	$8,053	$10,234
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$377	$1,495
On-Peak Market Energy	$2,799	$3,787	$4,917	$6,349	$7,954	$9,733	$11,342	$13,071	$16,002	$21,313	$25,914	$30,353	$35,262	$40,404	$45,830
Total Variable Costs	$5,957	$7,498	$9,374	$11,646	$14,249	$17,162	$20,416	$24,079	$28,553	$33,680	$39,513	$46,048	$53,304	$61,268	$70,355
DEMAND/FIXED COST ($000)															
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
New CT	$7,551	$7,590	$7,629	$7,670	$11,962	$12,025	$12,091	$12,157	$12,226	$17,105	$17,202	$17,300	$17,401	$17,504	$17,610
Total Fixed Costs	$12,455	$12,563	$12,675	$12,789	$17,156	$17,297	$17,442	$17,590	$17,742	$22,707	$22,891	$23,079	$23,272	$23,470	$23,673
TOTAL COST	**$18,412**	**$20,062**	**$22,049**	**$24,435**	**$31,406**	**$34,460**	**$37,858**	**$41,669**	**$46,295**	**$56,388**	**$62,404**	**$69,127**	**$76,576**	**$84,738**	**$94,028**
15-Year NPV (2015 $000):	**$347,544**														
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP	$92.43	$87.20	$81.74	$77.56	$74.05	$71.36	$69.44	$68.46	$69.05	$70.42	$72.15	$73.93	$75.76	$77.64	$79.57
Existing CT							$110.35	$114.11	$118.00	$122.02	$126.17	$130.55	$135.03	$139.64	$144.37
New CT														$6,622.75	$1,844.19
On-Peak Market Energy	$81.57	$82.19	$83.38	$84.14	$85.54	$87.37	$88.86	$89.47	$89.54	$91.75	$92.93	$94.32	$96.05	$98.19	$100.75

Financial Analysis

None216-100Coal

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
New Coal	118	140	166	195	227	260	295	332	369	407	446	486	526	564	602
SLP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing CT	0	0	0	0	0	0	0	0	0	0	0	0	0	4	10
New CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
On-Peak Market Energy	3	6	9	15	21	29	38	48	59	72	87	103	122	140	161
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
New Coal	$2,045	$2,481	$3,012	$3,637	$4,339	$5,107	$5,939	$6,839	$7,812	$8,838	$9,930	$11,082	$12,309	$13,553	$14,818
SLP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Existing CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$534	$1,461
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
On-Peak Market Energy	$254	$455	$774	$1,225	$1,819	$2,558	$3,449	$4,501	$5,731	$7,168	$8,851	$10,820	$13,123	$15,353	$17,861
Total Variable Costs	$2,311	$2,951	$3,804	$4,882	$6,181	$7,689	$9,414	$11,367	$13,572	$16,037	$18,812	$21,935	$25,467	$29,477	$34,179
DEMAND/FIXED COST ($000)															
New Coal (Including Transmission)	$22,146	$22,214	$22,285	$22,357	$22,431	$22,507	$22,585	$22,665	$22,747	$22,831	$22,917	$23,005	$23,095	$23,188	$23,283
New CT	$3,776	$3,795	$3,815	$3,835	$8,106	$8,149	$8,192	$8,237	$8,282	$13,138	$13,210	$13,284	$13,360	$13,438	$13,517
Total Fixed Costs	$25,921	$26,009	$26,100	$26,192	$30,537	$30,656	$30,777	$30,902	$31,029	$35,969	$36,127	$36,289	$36,455	$36,625	$36,800
TOTAL COST	**$28,232**	**$28,960**	**$29,904**	**$31,074**	**$36,719**	**$38,345**	**$40,191**	**$42,269**	**$44,602**	**$52,006**	**$54,939**	**$58,224**	**$61,923**	**$66,102**	**$70,978**
15-Year NPV (2015 $000):	**$353,725**														
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
New Coal	$204.75	$176.66	$152.83	$133.34	$118.02	$106.06	$96.61	$88.99	$82.75	$77.74	$73.61	$70.20	$67.33	$65.09	$63.33
Existing CT														$139.53	$144.29
New CT															
On-Peak Market Energy	$77.96	$79.60	$81.65	$84.18	$86.64	$89.18	$91.70	$94.27	$96.93	$99.63	$102.30	$104.97	$107.64	$109.58	$111.02

Financial Analysis
All216-SC

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	87	99	116	134	155	178	202	223	233	237	237	237	237	237	237
Existing CT	0	1	6	11	4	10	17	29	41	29	42	57	69	83	100
New CT	0	0	0	0	0	0	0	0	0	0	0	0	8	15	25
On-Peak Market Energy	34	45	53	64	89	101	114	127	154	214	255	295	334	374	411
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$3,147	$3,697	$4,440	$5,277	$6,273	$7,405	$8,648	$9,859	$10,603	$11,055	$11,376	$11,707	$12,047	$12,397	$12,757
Existing CT	$0	$131	$604	$1,138	$458	$1,078	$1,915	$3,298	$4,832	$3,499	$5,261	$7,441	$9,356	$11,600	$14,418
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$50	$1,031	$2,107	$3,597
On-Peak Market Energy	$2,799	$3,660	$4,332	$5,246	$7,510	$8,687	$9,891	$11,057	$13,360	$19,250	$23,125	$27,249	$31,623	$36,247	$41,035
Total Variable Costs	$5,957	$7,503	$9,393	$11,681	$14,263	$17,195	$20,480	$24,241	$28,824	$33,834	$39,794	$46,479	$54,093	$62,388	$71,847
DEMAND/FIXED COST ($000)															
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
SLP (Unit 1-3 FO&M)	$3,547	$3,636	$3,727	$3,820	$3,915	$4,013	$4,114	$4,216	$4,322	$4,430	$4,541	$4,654	$4,771	$4,890	$5,012
New CT	$3,776	$3,795	$3,815	$3,835	$8,106	$8,149	$8,192	$8,237	$8,282	$13,138	$13,210	$13,284	$13,360	$13,438	$13,517
Total Fixed Costs	$12,226	$12,404	$12,587	$12,774	$17,216	$17,434	$17,657	$17,886	$18,120	$23,170	$23,440	$23,718	$24,002	$24,293	$24,591
TOTAL COST	**$18,183**	**$19,907**	**$21,980**	**$24,455**	**$31,479**	**$34,628**	**$38,137**	**$42,127**	**$46,945**	**$57,004**	**$63,234**	**$70,197**	**$78,094**	**$86,681**	**$96,438**

15-Year NPV (2015 $000): $351,098

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP	$92.43	$87.20	$81.74	$77.56	$74.05	$71.36	$69.44	$68.46	$69.05	$70.42	$72.15	$73.93	$75.76	$77.64	$79.57
Existing CT		$93.36	$96.53	$99.82	$103.21	$106.72	$110.38	$114.18	$118.10	$122.08	$126.27	$130.57	$135.00	$139.59	$144.34
New CT												$35,080.90	$1,883.25	$1,029.43	$686.59
On-Peak Market Energy	$81.57	$81.93	$82.18	$81.90	$84.81	$85.75	$86.82	$87.03	$86.72	$89.89	$90.84	$92.45	$94.60	$97.00	$99.76

Financial Analysis

None216-LMS100

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LMS100	41	46	51	56	61	67	73	74	74	74	74	74	74	74	74
Existing CT	7	11	19	27	11	20	30	42	57	37	53	68	79	90	109
New CT	0	0	0	0	0	0	0	0	0	0	0	2	8	15	27
On-Peak Market Energy	73	88	105	126	175	202	230	262	297	368	406	445	486	528	563
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LMS100	$3,161	$3,633	$4,152	$4,727	$5,362	$6,056	$6,815	$7,175	$7,419	$7,672	$7,934	$8,204	$8,484	$8,773	$9,072
Existing CT	$602	$1,061	$1,833	$2,701	$1,184	$2,163	$3,283	$4,841	$6,762	$4,484	$6,661	$8,855	$10,643	$12,617	$15,728
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$248	$1,146	$2,135	$3,848
On-Peak Market Energy	$4,377	$5,369	$6,593	$8,173	$11,804	$14,034	$16,525	$19,662	$23,208	$30,000	$34,376	$39,158	$44,474	$50,178	$55,391
Total Variable Costs	$8,151	$10,078	$12,596	$15,622	$18,373	$22,278	$26,649	$31,705	$37,419	$42,187	$49,002	$56,498	$64,781	$73,740	$84,077
DEMAND/FIXED COST ($000)															
LMS100	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790
New CT	$3,776	$3,795	$3,815	$3,835	$8,106	$8,149	$8,192	$8,237	$8,282	$13,138	$13,210	$13,284	$13,360	$13,438	$13,517
Total Fixed Costs	$8,566	$8,585	$8,605	$8,625	$12,896	$12,939	$12,982	$13,027	$13,072	$17,928	$18,000	$18,074	$18,150	$18,228	$18,307
TOTAL COST	**$16,717**	**$18,663**	**$21,201**	**$24,247**	**$31,269**	**$35,216**	**$39,631**	**$44,731**	**$50,491**	**$60,115**	**$67,003**	**$74,572**	**$82,931**	**$91,968**	**$102,385**

15-Year NPV (2015 $000): $362,430

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP															
LMS100	$191.96	$182.95	$175.70	$169.84	$165.15	$161.53	$158.81	$160.82	$164.11	$167.50	$171.02	$174.65	$178.41	$182.30	$186.32
Existing CT	$90.54	$93.58	$96.67	$99.91	$103.50	$106.89	$110.46	$114.19	$118.06	$122.13	$126.26	$130.54	$134.95	$139.52	$144.29
New CT												$7,143.26	$1,712.76	$1,020.41	$652.30
On-Peak Market Energy	$59.68	$60.92	$62.70	$64.65	$67.48	$69.59	$71.82	$74.90	$78.21	$81.48	$84.75	$88.09	$91.50	$94.98	$98.45

Financial Analysis

None216-SC

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing CT	0	0	2	7	0	5	11	19	31	19	32	46	60	73	88
New CT	0	0	0	0	0	0	0	0	0	0	0	0	3	10	18
On-Peak Market Energy	121	146	173	203	248	284	322	360	397	460	501	543	585	625	666
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Existing CT	$0	$0	$149	$667	$0	$576	$1,249	$2,221	$3,718	$2,347	$4,071	$5,964	$8,106	$10,163	$12,736
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$395	$1,449	$2,604
On-Peak Market Energy	$8,500	$10,400	$12,628	$14,989	$18,950	$22,124	$25,634	$29,346	$33,117	$39,951	$44,542	$49,571	$54,888	$60,403	$66,332
Total Variable Costs	$8,511	$10,415	$12,796	$15,677	$18,972	$22,723	$26,909	$31,595	$36,864	$42,329	$48,644	$55,568	$63,425	$72,053	$81,711
DEMAND/FIXED COST ($000)															
New CC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
New CT	$11,327	$11,385	$11,444	$11,504	$15,817	$15,902	$15,989	$16,078	$16,170	$21,073	$21,193	$21,316	$21,442	$21,571	$21,704
Total Fixed Costs	$11,327	$11,385	$11,444	$11,504	$15,817	$15,902	$15,989	$16,078	$16,170	$21,073	$21,193	$21,316	$21,442	$21,571	$21,704
TOTAL COST	**$19,838**	**$21,799**	**$24,239**	**$27,181**	**$34,790**	**$38,625**	**$42,898**	**$47,673**	**$53,034**	**$63,401**	**$69,837**	**$76,884**	**$84,867**	**$93,624**	**$103,414**

15-Year NPV (2015 $000): $387,146

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP															
Existing CT			$96.53	$99.82		$106.72	$110.35	$114.14	$118.08	$122.03	$126.25	$130.58	$135.02	$139.60	$144.35
New CT													$7,454.01	$2,216.09	$1,346.86
On-Peak Market Energy	$70.01	$71.47	$72.80	$73.91	$76.46	$77.99	$79.72	$81.56	$83.43	$86.83	$88.99	$91.30	$93.86	$96.61	$99.54

Financial Analysis
All216-100CC

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	87	99	116	134	155	178	202	223	233	237	237	237	237	237	237
New CC	0	0	0	0	70	80	85	90	96	102	110	117	126	135	144
Existing CT	0	1	6	11	0	0	1	5	10	21	38	56	77	105	144
New CT	0	0	0	0	0	0	0	0	0	0	0	0	0	3	10
On-Peak Market Energy	34	45	53	64	23	32	46	60	89	120	149	179	208	229	237
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$3,147	$3,697	$4,440	$5,277	$6,273	$7,405	$8,648	$9,859	$10,603	$11,055	$11,376	$11,707	$12,047	$12,397	$12,757
New CC	$0	$0	$0	$0	$5,045	$5,964	$6,562	$7,213	$7,967	$8,807	$9,838	$10,971	$12,213	$13,582	$15,096
Existing CT	$0	$131	$604	$1,138	$0	$0	$97	$625	$1,217	$2,550	$4,782	$7,248	$10,386	$14,707	$20,938
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$376	$1,436
On-Peak Market Energy	$2,799	$3,660	$4,332	$5,246	$1,353	$1,937	$3,138	$4,467	$6,962	$9,904	$12,634	$15,658	$18,716	$21,172	$22,711
Total Variable Costs	$5,957	$7,503	$9,393	$11,681	$12,694	$15,331	$18,471	$22,192	$26,778	$32,346	$38,662	$45,618	$53,397	$62,272	$72,977
DEMAND/FIXED COST ($000)															
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
SLP (Unit 1-3 FO&M)	$3,547	$3,636	$3,727	$3,820	$3,915	$4,013	$4,114	$4,216	$4,322	$4,430	$4,541	$4,654	$4,771	$4,890	$5,012
New CC	$0	$0	$0	$0	$14,836	$14,901	$14,968	$15,036	$15,106	$15,178	$15,251	$15,327	$15,404	$15,483	$15,564
New CT	$3,776	$3,795	$3,815	$3,835	$3,856	$3,877	$3,898	$3,921	$3,944	$3,967	$3,991	$4,016	$4,041	$4,067	$4,093
Total Fixed Costs	$12,226	$12,404	$12,587	$12,774	$27,801	$28,063	$28,331	$28,606	$28,888	$29,176	$29,472	$29,776	$30,087	$30,405	$30,732
TOTAL COST	**$18,183**	**$19,907**	**$21,980**	**$24,455**	**$40,495**	**$43,394**	**$46,802**	**$50,798**	**$55,666**	**$61,522**	**$68,135**	**$75,393**	**$83,484**	**$92,677**	**$103,709**

15-Year NPV (2015 $000): $389,434

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP	$92.43	$87.20	$81.74	$77.56	$74.05	$71.36	$69.44	$68.46	$69.05	$70.42	$72.15	$73.93	$75.76	$77.64	$79.57
New CC					$285.28	$261.90	$253.98	$246.93	$240.55	$235.23	$229.09	$223.84	$219.42	$215.69	$212.58
Existing CT		$93.36	$96.53	$99.82			$109.96	$113.70	$117.57	$121.71	$125.95	$130.28	$134.77	$139.41	$144.91
New CT														$1,642.15	$553.75
On-Peak Market Energy	$81.57	$81.93	$82.18	$81.90	$58.08	$61.04	$68.78	$74.05	$78.48	$82.61	$84.94	$87.48	$89.85	$92.48	$95.65

Financial Analysis

45216-100CC

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	87	99	116	134	155	178	202	223	233	237	237	237	237	237	237
New CC	32	41	50	60	70	80	85	90	96	102	110	117	126	135	144
CTs	0	0	0	0	0	0	1	5	10	3	9	19	38	56	81
On-Peak Market Energy	2	5	9	15	23	32	46	60	89	137	178	215	248	281	311
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$3,147	$3,697	$4,440	$5,277	$6,273	$7,405	$8,648	$9,859	$10,603	$11,055	$11,376	$11,707	$12,047	$12,397	$12,757
New CC	$2,054	$2,686	$3,390	$4,174	$5,045	$5,964	$6,562	$7,213	$7,967	$8,807	$9,838	$10,971	$12,213	$13,582	$15,096
CTs	$0	$0	$0	$40	$0	$0	$97	$625	$1,217	$418	$1,098	$2,503	$5,054	$7,868	$11,620
On-Peak Market Energy	$93	$259	$473	$862	$1,353	$1,937	$3,138	$4,467	$6,962	$11,166	$15,147	$19,027	$22,560	$26,330	$30,007
Total Variable Costs	$5,305	$6,657	$8,320	$10,373	$12,694	$15,331	$18,471	$22,192	$26,778	$31,476	$37,490	$44,242	$51,909	$60,213	$69,519
DEMAND/FIXED COST ($000)															
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
New CC	$14,591	$14,650	$14,710	$14,772	$14,836	$14,901	$14,968	$15,036	$15,106	$15,178	$15,251	$15,327	$15,404	$15,483	$15,564
New CT	$0	$0	$0	$0	$4,251	$4,272	$4,294	$4,316	$4,339	$9,171	$9,219	$9,269	$9,319	$9,371	$9,424
Total Fixed Costs	$19,495	$19,624	$19,756	$19,892	$24,281	$24,445	$24,613	$24,785	$24,961	$29,951	$30,160	$30,374	$30,594	$30,819	$31,050
TOTAL COST	**$24,800**	**$26,280**	**$28,076**	**$30,264**	**$36,975**	**$39,775**	**$43,083**	**$46,976**	**$51,739**	**$61,426**	**$67,650**	**$74,616**	**$82,503**	**$91,033**	**$100,569**

15-Year NPV (2015 $000): $396,788

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP	$92.43	$87.20	$81.74	$77.56	$74.05	$71.36	$69.44	$68.46	$69.05	$70.42	$72.15	$73.93	$75.76	$77.64	$79.57
New CC	$513.13	$422.60	$361.57	$317.83	$285.28	$261.90	$253.98	$246.93	$240.55	$235.23	$229.09	$223.84	$219.42	$215.69	$212.58
Existing CT				$99.46			$109.96	$113.70	$117.57	$121.58	$125.72	$130.14	$134.69	$139.32	$144.13
New CT															
On-Peak Market Energy	$49.47	$51.18	$53.14	$55.83	$58.08	$61.04	$68.78	$74.05	$78.48	$81.26	$85.10	$88.33	$91.02	$93.81	$96.39

Appendix IV -

- **End Use Survey & Summary of Results**
- **End Use Survey Question Forms for Residential, Commercial and Industrial Customers**
- **“Next Level” Triad Report**
- **Task Force Recommendations**
- **Residential & Commercial End Use Information**
- **Statistical Relationship Photovoltaic Generation & Electric Utility Demand in Minnesota (1996 – 2002)**

Task Force Recommendations

Phase II Task Force Meeting
Tuesday, October 26, 2004
12:00pm – 2:00pm
RPU Training Room

Meeting Minutes

I. Greetings and Introductions

Mary Tompkins, RPU Manager of Customer Service, welcomed the group and especially thanked the Task Force members for attending.

II. Summary of End Use Survey and Cost Benefit Analysis

Kiah Harris from Burns & McDonnell explained the outline of the meeting. He will go through the summary of the End Use Survey and answer questions. Following his presentation, each Task Force member will have 5 minutes to give their responses to the seven questions given to them in their packets. Kiah also explained that the process and future of the Task Force on a going forward basis is questionable at this point.

Kiah began his presentation with the explanation of appliance and equipment inventory, or opportunities, in Rochester. One Task Force member expressed his objection of the term inventory and from here on, the term would be referred to as opportunities.

A comparison of Residential and Commercial estimated demand and energy impacts were discussed. On the Residential side, a comparison was made between the conversion to Energy Star appliances and the conversion to gas appliances. The Commercial side compared efficiency conversions to those converted to gas. There was a lot less opportunity on the Commercial side when converting to gas. Residential showed the opposite with more savings when converted to gas.

Kiah then reviewed the Benefit/Cost Analysis for Residential and Commercial while comparing Participant to Societal, or those that don't participate but are affected.

Florence Sandok, Task Force member, added that customers were not asked energy efficiency questions on the Commercial survey. There are other solutions besides appliances. She gave the example that Mayo has some lights that turn on when people enter the room and shut off when they exit.

Florence also expressed the idea that global warming may “skew” things – i.e. air conditioning and natural disasters. Insurance companies are now taking this into account with increased values of appliances.

Stephanie Yrjo, RPU Commercial Account Representative, further explained that the Cost/Benefit Analysis took specific motors and looked at the spectrum. We will look at costs and refine the numbers at a later date.

Keith Butcher, Manager of External Affairs – Center for Energy and Environment, supported these assumptions.

III. Sharing of Task Force Ideas and Recommendations

*****

Some questions to consider in anticipation of the last Task Force meeting on October 26, 2004….

1. What pricing conventions could RPU develop to make energy conservation efforts more effective?
2. What do you think is the largest hindrance to customer participation in programs? What role could RPU play in removing that hindrance?
3. Rank the importance of RPU's conservation programs (1 being most important, 5 being least important).
   - Pricing signals ______
   - Incentives ______
   - Education ______
   - Promotion ______
   - Other (please specify) ______
4. In your opinion, what is the best way for RPU to encourage participation in renewable energy programs?
   - Offer the customer a choice where they pay a premium to purchase renewable energy.
   - Subsidize (build into rate structure) some or all of the cost of a renewable program.
5. In your opinion, what is the most effective way for RPU to administer its conservation programs?
   - By customer choice – promoting rebates, special rates, education, etc.
   - By building into rates – all customers participate in conservation through the rate structures and/or required programs.
6. Please suggest any conservation programs not discussed at Task Force meetings that you feel would be of value for RPU to research.
7. Would you be willing to promote RPU’s programs (e.g., energy efficient lighting for homes) through community groups or committees with which you are involved?

*****

Task Force Member 1

#1 Dual meters offering – peak vs. non-peak. Energy calculator on website would be good to have.

#3 Education is important and ongoing. Incentives are a good way to get people to act.

#5 Customer Choice
#6 Transfer coal on rail vs. trucks
#7 Yes – I would be willing to serve on a community group.

Task Force Member 2

#2 Pre and post-inspections for small dollar amount rebates make the biggest hindrances – the hassle factor.
#4 Encourage renewable energy participation – the big one is wind. Incentives will come naturally for wind as turbines are built and the cost drops below other power.
#5 Customer Choice.
#6 Air handling units waste energy. Do commissioning. Vending misers are a good savings.

Task Force Member 3

#1 Money saving on bills. Anything that can be credited on a bill (example: timers for A/C).
#2 The biggest hindrance is cutting out the UPC symbol for the rebate and mailing it in. Instead, just bring in a coupon. Make things easier.
#3 Education. Start with educating the elementary kids and they will educate the parents. Kids put great pressure on parents. Incentives is number 2 and promotion is number 3.
#4 Customer Choice.
#5 Customer Choice.
#6 Onsite exchange of working light bulbs for CFL's. This would be very little hassle. Turn off the lights! This is especially important in big buildings. Include store coupons in bills that customers could take with them to purchase CFL's and other energy efficient products. Lobby Congress for tax credits to providers of alternative energy choices. In lieu of off-peak storage capability and technology, manufacture hydrogen and oxygen for on-peak demand.

Task Force Member 4

This Task Force member would have liked to be involved from the beginning and been able to set the number of meetings. She also mentioned she had good ideas on how to structure the group and whether we want to continue its existence.

#1 Price incentives - Schedule rates on amounts of use and time of use.
#2 People don't know about the reward. Example: Paul Wellstone commercial. Do fun ads like his. Do more education and advertising.
#4 Subsidize the renewable rate program. This should include the WHOLE cost including health costs and externalities like pollution, etc. Penalize those not participating. Education is the key.
#5 Build into rates. All customers participate in conservation through the rate structures and/or required programs. Penalize those customers that don't participate.

#6 She wants to see more task forces.

How much has RPU paid consultants? Should hire a knowledgeable energy consultant to design the best program for a customized conservation program for the Rochester community. Teach Community Ed, tree planting, installing wind towers, student education programs, partner with builders, and install efficient home lighting systems.

#7 She would be willing to promote programs. She wants to be involved in the fine tuning. Keep it simple. Continue the process as we have just begun. Rebates for buying compact fluorescent light bulbs should be paid out where the light bulb is bought.

ADDITIONAL THOUGHTS: Send staff to green festival conferences. Have a tour of energy efficient homes in Rochester. City – wide contests for best energy efficient ideas with energy efficient award.

Task Force Member 5

This task force member explained that the rebates did not incent him to buy certain appliances. What is the motivation? Why buy a $700 refrigerator if you don't have $700?

RPU bill – Why is it that way? Why is it as high as it is? Can someone come to the house to say why it is so high? Be more proactive. Does RPU have a home auditor? (Stephanie confirmed that RPU can do this for a fee of approximately $50). $50 fee would be a roadblock in having that done.

Task Force Member 6

He sees comparable things. To capture the life cycle, it would take 20 to 25 years.

Partner with vendors for instant rebates.

Partner with builders and building/mechanical codes. Example is gas piping – the cost is high to put that in for a range.

Cost to conversion – minimum vs. maximum.

Pay 100% of difference or change the codes.

#3 Incentives is number 1. 70% of those that get a high efficiency furnace are free riders. The builder would have put them in anyway. The builder puts in a 92% efficient furnace to meet code and the customer gets the rebate.

Promotions is number 2. This includes education. Educate the kids and start young. Discontinue the bill inserts – most are discarded without being read.

#4 Customer Choice. Right now, it does not make financial sense.

#5 Build into the rates. Build the infrastructure into the rates.

#6 Work your partnerships. Work with vendor installers including appliance manufacturers.

Distributive generation. Larger companies are doing this out west. Partner with Mayo and IBM to do this. Incentives for this.

Energy Committee for Rochester Schools – Rory is involved with this group. The idea is to identify where you are wasting money. Who will manage the lights, remove refrigerators and heaters out of the classrooms, and removal of other teacher conveniences. Help facilities manage their energy and identify opportunities with an “audit for energy conservation”.

Develop software program for auditing?

#7 Yes – he is willing to promote RPU programs.

Task Force Member 7

#1 Variable rates for peak – dual meters.
#2 Largest hindrance is cost effectiveness
#3 Incentives
#4 Subsidize/build into rates.
#5 Build into the rates – it will be easier.
#6 Night rates

Even out peak demand – energy storage.

How will we find more energy? Any power Ok – even nuclear which has no pollution and is cheap.

#7 Yes-if cost effective.

Task Force Member 8

#1 How much you use and when.

#2 The biggest hindrance is the lack of incentive. Change the rate structure to make customers more aware/ pay more attention. Residential participation is better than the commercial side. Put a greater emphasis on the commercial customer, where there is more potential for energy savings.

#3
1. Price
2. Incentives
3. Education/Promotion (Should be together)

#4 Wind is getting more competitive. Subsidize some or all of the cost. We need availability of transmission facilities for wind to get to the grid.

#5 The most effective way is to build into the rates. He doesn’t want to subsidize someone else’s power.

#6 Ground source heat pumps – work with developers to put in a community look. This is cheaper that each putting their own in. Partner with sewage treatment for heating. Educate sales people on advantages like energy savings of upgrading appliances.

#7 Yes, he is willing to promote RPU programs.

Task Force Member 9

The only complaint that others had about RPU was the severe tree trimming on the boulevard.

#1 According to this Task Force member, Big G is not supporting the purchase of the Energy Star ranges.

Did not like the hydrant fee.

Otherwise no complaints – RPU is #1.

#7 Yes, she is willing to promote RPU programs.

IV. ***Wrap Up***

- Florence suggested a poll of those who wanted to continue on the task force. Mary Tompkins took the poll and the majority (7-1) wanted to continue.
- Task force members would have liked to decide how many meetings and how they would have been structured, ongoing or not. They wanted to be involved from the beginning and to have more involvement.
- Florence informed the group that this is a public utility and if the community wants a task force, they should be able to have one.
- Kiah intercepted that everyone has a representative on the Board.
- Rory also supported this idea that RPU should make the decisions because of the level of expertise.
- Florence would still like to collaborate as partners.
- Bill explained that he had been involved with SLP pollution discussions and that RPU has become more open to community groups. He thinks we should keep on with the community task force. He is pleased with the forthcoming of RPU and the opportunity to get involved. Both would benefit from an ongoing citizens committee. He also suggested having terms assigned so others can get involved. Bill said this would not be unique in a city – other city and county departments have citizen task forces.
- Mary Tompkins confirmed that she would bring all this information back for discussion as the majority is interested in further participation of “citizen’s advisory groups”.
- Kiah summarized the process of RPU at this point. The suggestions will be put into a financial model to see the impact on the rates. This will be done over the next month or so.
- Stephanie inserted the fact that RPU is looking at conservation programs with Owatonna and Austin. RPU will definitely take the suggestions into account.

- Mary also informed the group that next year RPU is looking at doing pre-payment metering. This would be able to track usage and has been very successful in other cities.
- Kiah reminded the task force members to also send us their comments after the meeting too.
- Larry Koshire, RPU General Manager, closed the meeting thanking everyone for their participation.

Flipchart notes:

- Straw Pole: Majority interested in further participation. Citizen Advisory Groups.
- TOU rates
- Rebates – hassle free
- Customer choice – flexibility

Residential & Commercial End Use Information

Estimated Residential Demand Savings
Note: RPU summer peak is about 4pm
Air conditioner demand going to SEER 12

MWh saved = 7,087
Assume two thirds of energy used in July and August
Energy for July or August peak= 2338.86312 MWh per month
Assume half of the energy saved during 8 hours
Energy saved during 8 hours = 1169.43156 MWh
Energy saved per hour per day 4.71544984 MWh
Demand on peak = 4.71544984 MW

Demand reductions per ac are .6 to 1.2kW depending on if the same size or reduced size is installed. Based on the diversity on the RPU system, the average natural demand reduction would be .2 to .4kW.

Refrigerators

MWh saved = 1,252
Saved per day= 3
Assume half of energy used during 8 hours= 1.714685
Energy per hour 0.214336 MWh
Average Demand on peak 0.214336 MW

Freezers

MWh saved= 98
Assume averaged across the day
Ave MW= 0.011242 MW

Compact Flourescent

Energy savings based on 4 hours per day
Not coincident with RPU peak, therefore, no demand savings

Washing Machine

Assume same diversity as refrigerators
MWh saved = 13,973
Saved per day= 38.28084 MWh
Assume half of energy used during 8 hours= 19.14042
Energy per hour 2.392552 MWh
Average Demand on peak 2.392552 MW

Dishwasher

Not coincident with RPU peak

Water Heater

MWh used= 21,048
Average per day= 57.6661 MWh
Majority of energy is used in morning between 5 to 7 and evening from 7 to 10
Assume half is during this period
Average for rest of hours per hour = 1.517529 MW

Dryer

Assume same use as washing machine

MWh used=	30,190	
Used per day=	82.71312	MWh
Half of energy in 8 hour period	41.3565616	
Energy per hour	5.16957021	MWh
Ave demand on peak	5.16957021	MW

Blower motor

From Ben cost study Average energy reduction =	570	kWh
Average demand reduction =	0.19	kW
Number of gas furnaces =	35867	
Number of electric furnaces =	552	
	36419	
Max Energy savings MWh	20758.83	

Summary demand reductions due to efficiencies

	Demand Reductions (MW
Appliance	Maximum
Air Conditioners	4.7
Rerigerators	0.22
Freezers	0.011
Washing Machine	2.35
	7.281
Conversion to gas appliances	
Water Heaters	1.52
Dryers	5.2
	6.72
Total	14.001

Load Management		Residential	Commercial
Total Central AC units		36064	1825
Current Partners		8461	
Reductions per AC kW	0.98		
Estimated current reductions kW		8292	
Estimated maximum reductions kW		35343	
Estimated max red when SEER 12		25245	
(assumes .7kW per point)			568
Total Water Heaters		4375	
Current Partners		905	
Reductions per AC kW	0.68		
Estimated current reductions kW		615	

Estimated Residential Energy Savings

Appliance summary	Conversions		Estimated Energy Savings Each (kWh)	Total (MWh)	Source for savings		Maximum Estimated Demand Savings Coincident with RPU MW	
Energy Star or other Efficiency								
Central Air more than	5 yrs	20484 (No. of customers)	346	7,087	calculator		4.7	
Room Air more than	5 yrs	2618 (No. of units)	58	152	calculator		0.1	
Refrigerator more than	5 yrs	13176 (No. of units)	95	1,252	calculator		0.2	
Freezer more than	5 yrs	1231 (No. of units)	80	98	calculator		0.0	
No Compact FL		15214 (No. of customers)	124	1,887	calculator		0.0	
Washing Machine		38705 (No. of customers)	361	13,973	calculator	Includes dryer savings	2.4	
Dishwasher-heated drying		9792 (No. of customers)	103	1,009	calculator		0.0	
HVAC Blower		36419 (No. of units)	570	20,759	Bencost study		6.9	Ben cost assumed .19kW per mot
			Total Usage					
Other Options			Each (kWh)	Total (MWh)				
Electric heat-Main		788 (No. of customers)	43174	34,021	energyguide.com web site		Not on summer peak	
Electric auxiliary heat		3035 (No. of customers)					Not on summer peak	
Dryer		30342 (No. of customers)	995	30,190	Cornhusker Power/Neb web sites		5.2	
Spa/Hot tub		585 (No. of customers)	1680	983	Cornhusker Power/Neb web sites		minimal demand	
Water Heater		4375 (No. of customers)	4811	21,048	Cornhusker Power/Neb web sites		1.5	
Range/Oven		30704 (No. of customers)	256	7,860	Cornhusker Power/Neb web sites		Not applicable to DSM	

Rochester Public Utilities
Financial Model Results
Scenario: No DSM
Scenario Description: Recommended expansion plan from Part IV with the forecast unaffected by demand side management
All dollar values in $1,000s

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 Sales of Electricity - Retail	$ 94,278	$ 98,169	$ 100,761	$ 104,752	$ 108,387	$ 112,362	$ 117,636	$ 123,509	$ 129,063	$ 133,798	$ 140,081	$ 147,007	$ 153,692	$ 162,412	$ 171,790
2 Other Revenues	19,210	20,818	21,317	20,881	21,455	25,334	23,306	24,016	24,726	25,473	26,258	20,612	20,672	21,359	22,034
3 Total Operating Revenues	$ 113,488	$ 118,988	$ 122,078	$ 125,633	$ 129,842	$ 137,696	$ 140,942	$ 147,525	$ 153,789	$ 159,270	$ 166,339	$ 167,619	$ 174,365	$ 183,771	$ 193,823
4															
5 Power Supply Costs	69,738	70,091	71,632	73,036	74,851	79,946	79,455	81,351	82,946	84,886	87,147	84,930	87,655	90,687	94,233
6 Net Other Operating Expenses	27,169	29,430	30,854	32,029	34,667	37,187	38,685	40,606	42,979	45,864	49,193	51,498	53,560	56,807	61,121
7 Total Operating Expenses	$ 96,907	$ 99,521	$ 102,485	$ 105,065	$ 109,518	$ 117,132	$ 118,140	$ 121,958	$ 125,925	$ 130,750	$ 136,340	$ 136,428	$ 141,215	$ 147,494	$ 155,353
8															
9 Operating Income	16,581	19,467	19,593	20,568	20,324	20,563	22,802	25,567	27,864	28,521	29,998	31,191	33,149	36,277	38,470
10 Interest Expense, Incl AFUDC	(2,597)	(2,325)	(2,242)	(2,848)	(4,871)	(4,897)	(4,723)	(4,554)	(4,426)	(8,773)	(7,278)	(7,857)	(7,589)	(15,388)	(12,919)
11 Interest and Other Income	667	677	731	795	808	492	445	442	510	1,024	1,030	637	717	1,515	1,465
12 Income B4 Transfer/Cap Contribution	$ 14,651	$ 17,818	$ 18,082	$ 18,515	$ 16,261	$ 16,158	$ 18,524	$ 21,456	$ 23,948	$ 20,773	$ 23,750	$ 23,970	$ 26,277	$ 22,404	$ 27,016
13															
14 Net Transfers & Contributions In (Out)	(7,983)	(8,404)	(8,630)	(9,109)	(9,567)	(10,069)	(10,597)	(11,186)	(11,749)	(12,365)	(13,013)	(13,730)	(14,429)	(15,178)	(15,982)
15															
16 Change in Net Assets	$ 6,668	$ 9,414	$ 9,453	$ 9,406	$ 6,693	$ 6,089	$ 7,927	$ 10,270	$ 12,199	$ 8,408	$ 10,737	$ 10,241	$ 11,848	$ 7,226	$ 11,034
17															
18															
19															
20 01/01 Cash Balance	$ 14,217	$ 12,940	$ 14,825	$ 16,521	$ 19,030	$ 17,349	$ 14,951	$ 14,276	$ 14,755	$ 18,766	$ 48,504	$ 19,127	$ 22,672	$ 24,382	$ 75,105
21															
22 Change in Net Assets	6,668	9,414	9,453	9,406	6,693	6,089	7,927	10,270	12,199	8,408	10,737	10,241	11,848	7,226	11,034
23 Operating & Capital Activity	(11,265)	(5,769)	(5,922)	(15,686)	(40,651)	(5,621)	(5,585)	(6,606)	(4,830)	(37,300)	(36,297)	(2,661)	(5,873)	(62,765)	(60,028)
24 Bond Principle Payments	(1,681)	(1,760)	(1,835)	(2,211)	(2,724)	(2,866)	(3,017)	(3,185)	(3,358)	(4,270)	(3,817)	(4,035)	(4,265)	(4,738)	(5,028)
25 Bond Sale Proceeds	5,000	-	-	11,000	35,000	-	-	-	-	62,900	-	-	-	111,000	-
26															
27 Net Changes in Cash	$ (1,277)	$ 1,885	$ 1,696	$ 2,509	$ (1,681)	$ (2,398)	$ (675)	$ 479	$ 4,011	$ 29,738	$ (29,377)	$ 3,545	$ 1,711	$ 50,723	$ (54,022)
28															
29 12/31 Cash Balance	12,940	14,825	16,521	19,030	17,349	14,951	14,276	14,755	18,766	48,504	19,127	22,672	24,382	75,105	21,083
30 Reserve Minimum	10,364	10,393	10,744	12,077	13,887	12,675	12,933	13,214	14,212	16,401	17,036	16,012	16,864	20,381	21,283
31 Excess (Deficit) from Minimum	$ 2,576	$ 4,432	$ 5,777	$ 6,954	$ 3,462	$ 2,276	$ 1,343	$ 1,541	$ 4,554	$ 32,103	$ 2,090	$ 6,660	$ 7,519	$ 54,724	$ (200)
32															
33 Rate Change	3.0%	1.0%	0.0%	1.0%	1.0%	1.0%	2.0%	2.0%	2.0%	1.0%	2.0%	2.0%	2.0%	3.0%	3.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 3,937	$ 4,759	$ 4,950	$ 4,014	$ 4,791	$ 5,047	$ 5,793	$ 6,127	$ 4,835	$ 5,955	$ 5,880	$ 5,836	$ 7,314	$ 7,659	$ 6,430
37 Transmission Line Additions	-	-	-	11,000	11,000	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	-	-	-	-	31,450	31,450	-	-	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	55,500	55,500
40 Emission Control Eqpt Major Additions	-	-	-	-	24,000	-	-	-	-	-	-	-	-	-	-
41 Other	12,315	7,063	7,422	7,758	8,920	8,477	9,067	9,560	9,619	11,164	11,610	11,303	12,238	14,268	14,497
42 Total Capital Expenditures	$ 16,252	$ 11,822	$ 12,373	$ 22,772	$ 48,711	$ 13,524	$ 14,860	$ 15,687	$ 14,454	$ 48,568	$ 48,940	$ 17,139	$ 19,552	$ 77,427	$ 76,428
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ 5,000	$ -	$ -	$ 11,000	$ 35,000	$ -	$ -	$ -	$ -	$ 62,900	$ -	$ -	$ -	$ 111,000	$ -
47 Debt Service Payments	$ 4,183	$ 4,187	$ 4,183	$ 5,189	$ 7,868	$ 7,867	$ 7,866	$ 7,872	$ 7,875	$ 12,695	$ 12,001	$ 12,007	$ 12,013	$ 19,461	$ 19,461
48 Debt Outstanding	$ 48,369	$ 46,610	$ 44,775	$ 53,564	$ 85,840	$ 82,975	$ 79,957	$ 76,772	$ 73,415	$ 132,045	$ 128,228	$ 124,193	$ 119,928	$ 226,191	$ 221,162
49 Debt Service Coverage Ratio	5.4	6.5	6.6	5.7	3.9	3.8	4.2	4.6	5.0	3.2	4.0	3.8	4.1	2.7	3.2

Rochester Public Utilities
Financial Model Results
Scenario: No DSM
Scenario Description: Recommended expansion p
All dollar values in $1,000s

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 Sales of Electricity - Retail	$ 176,752	$ 180,997	$ 185,962	$ 194,701	$ 206,240	$ 217,636	$ 230,209	$ 243,394	$ 257,947	$ 272,333	$ 285,002	$ 301,388	$ 318,716	$ 337,042	$ 352,962
2 Other Revenues	40,750	40,874	40,591	40,146	40,120	40,247	40,556	40,798	40,999	40,943	41,218	41,613	42,318	42,507	42,943
3 Total Operating Revenues	$ 217,502	$ 221,871	$ 226,553	$ 234,847	$ 246,360	$ 257,883	$ 270,765	$ 284,192	$ 298,946	$ 313,276	$ 326,221	$ 343,001	$ 361,034	$ 379,549	$ 395,905
4															
5 Power Supply Costs	105,357	108,329	111,895	115,885	120,746	125,823	131,700	137,151	144,166	151,536	159,937	169,473	179,602	190,986	202,818
6 Net Other Operating Expenses	66,660	69,763	72,707	76,094	80,070	84,284	88,566	92,337	96,865	101,300	105,474	111,029	116,064	121,312	127,639
7 Total Operating Expenses	$ 172,017	$ 178,092	$ 184,601	$ 191,979	$ 200,817	$ 210,107	$ 220,265	$ 229,489	$ 241,031	$ 252,836	$ 265,410	$ 280,502	$ 295,665	$ 312,297	$ 330,457
8															
9 Operating Income	45,485	43,779	41,951	42,867	45,544	47,776	50,500	54,703	57,916	60,440	60,810	62,499	65,368	67,251	65,448
10 Interest Expense, Incl AFUDC	(13,957)	(13,628)	(13,243)	(12,864)	(12,512)	(15,892)	(14,290)	(14,457)	(13,954)	(13,384)	(12,775)	(12,209)	(11,758)	(11,117)	(10,560)
11 Interest and Other Income	675	769	835	832	863	1,271	1,215	786	845	957	1,005	1,044	1,157	1,230	1,186
12 Income B4 Transfer/Cap Contribution	$ 32,203	$ 30,920	$ 29,544	$ 30,836	$ 33,894	$ 33,156	$ 37,424	$ 41,032	$ 44,806	$ 48,013	$ 49,040	$ 51,334	$ 54,768	$ 57,365	$ 56,074
13															
14 Net Transfers & Contributions In (Out)	(16,451)	(16,851)	(17,320)	(18,228)	(19,223)	(20,192)	(21,262)	(22,378)	(23,611)	(24,813)	(26,102)	(27,478)	(28,926)	(30,450)	(32,054)
15															
16 Change in Net Assets	$ 15,752	$ 14,069	$ 12,224	$ 12,608	$ 14,672	$ 12,964	$ 16,162	$ 18,654	$ 21,195	$ 23,200	$ 22,938	$ 23,856	$ 25,842	$ 26,915	$ 24,019
17															
18															
19															
20 01/01 Cash Balance	$ 21,083	$ 23,209	$ 27,269	$ 27,559	$ 27,107	$ 29,592	$ 53,880	$ 25,887	$ 25,731	$ 29,730	$ 33,099	$ 32,879	$ 35,682	$ 40,287	$ 40,502
21															
22 Change in Net Assets	15,752	14,069	12,224	12,608	14,672	12,964	16,162	18,654	21,195	23,200	22,938	23,856	25,842	26,915	24,019
23 Operating & Capital Activity	(8,287)	(4,345)	(5,918)	(6,674)	(5,401)	(33,913)	(35,852)	(9,991)	(8,828)	(10,946)	(13,725)	(13,499)	(13,192)	(18,132)	(18,012)
24 Bond Principle Payments	(5,338)	(5,664)	(6,016)	(6,386)	(6,785)	(7,818)	(8,304)	(8,819)	(8,369)	(8,885)	(9,433)	(7,554)	(8,045)	(8,568)	(9,125)
25 Bond Sale Proceeds	-	-	-	-	-	53,056	-	-	-	-	-	-	-	-	-
26															
27 Net Changes in Cash	$ 2,126	$ 4,060	$ 290	$ (452)	$ 2,485	$ 24,288	$ (27,993)	$ (156)	$ 3,999	$ 3,369	$ (221)	$ 2,803	$ 4,605	$ 216	$ (3,118)
28															
29 12/31 Cash Balance	23,209	27,269	27,559	27,107	29,592	53,880	25,887	25,731	29,730	33,099	32,879	35,682	40,287	40,502	37,384
30 Reserve Minimum	19,729	20,761	21,574	22,391	24,109	26,876	27,519	26,631	28,406	30,132	30,725	32,194	34,428	35,869	37,047
31 Excess (Deficit) from Minimum	$ 3,480	$ 6,508	$ 5,985	$ 4,716	$ 5,483	$ 27,005	$ (1,631)	$ (899)	$ 1,324	$ 2,967	$ 2,154	$ 3,489	$ 5,859	$ 4,633	$ 337
32															
33 Rate Change	0.0%	0.0%	0.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.0%	3.0%	3.0%	3.0%	2.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 7,792	$ 7,878	$ 9,108	$ 9,439	$ 8,159	$ 9,803	$ 11,680	$ 11,162	$ 9,840	$ 11,669	$ 13,683	$ 13,248	$ 12,132	$ 16,074	$ 16,228
37 Transmission Line Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	26,528	26,528	-	-	-	-	-	-	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41 Other	14,097	14,760	15,777	16,578	16,961	18,872	20,226	20,286	20,829	22,309	23,891	24,838	25,650	27,945	29,237
42 Total Capital Expenditures	$ 21,889	$ 22,638	$ 24,885	$ 26,017	$ 25,121	$ 55,203	$ 58,434	$ 31,448	$ 30,669	$ 33,977	$ 37,575	$ 38,086	$ 37,782	$ 44,019	$ 45,465
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ -	$ -	$ -	$ -	$ -	$ 53,056	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47 Debt Service Payments	$ 19,461	$ 19,458	$ 19,460	$ 19,459	$ 19,463	$ 23,525	$ 23,525	$ 23,524	$ 22,526	$ 22,525	$ 22,523	$ 20,060	$ 20,060	$ 20,060	$ 20,060
48 Debt Outstanding	$ 215,824	$ 210,160	$ 204,143	$ 197,757	$ 190,971	$ 236,209	$ 227,905	$ 219,086	$ 210,718	$ 201,833	$ 192,400	$ 184,846	$ 176,801	$ 168,233	$ 159,108
49 Debt Service Coverage Ratio	3.3	3.3	3.2	3.3	3.5	3.0	3.4	3.4	3.7	3.9	3.9	4.5	4.7	4.9	4.9

Rochester Public Utilities
Financial Model Results
Scenario: Aggressive DSM, Coal & Gas Mix
Scenario Description: Recommended plan adjusted by using the aggressive demand side management results with SLP operating on coal and adjustments to the new resources
All dollar values in $1,000s

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 Sales of Electricity - Retail	$ 93,770	$ 95,224	$ 97,875	$ 100,695	$ 105,144	$ 107,968	$ 110,973	$ 115,520	$ 118,623	$ 123,366	$ 128,300	$ 135,891	$ 141,730	$ 145,470	$ 149,169
2 Other Revenues	19,117	20,615	21,131	20,668	21,261	25,151	23,169	23,906	24,643	25,417	26,226	20,683	20,927	21,671	22,446
3 Total Operating Revenues	$ 112,887	$ 115,839	$ 119,006	$ 121,363	$ 126,405	$ 133,118	$ 134,141	$ 139,426	$ 143,265	$ 148,784	$ 154,526	$ 156,574	$ 162,657	$ 167,141	$ 171,616
4															
5 Power Supply Costs	69,442	68,037	69,126	69,873	71,030	75,337	74,480	75,818	76,986	78,372	79,895	78,679	80,456	81,165	83,004
6 Net Other Operating Expenses	27,338	29,754	31,486	32,895	35,516	38,069	39,755	41,593	43,567	45,558	47,618	49,178	52,621	55,240	57,597
7 Total Operating Expenses	$ 96,780	$ 97,792	$ 100,612	$ 102,768	$ 106,546	$ 113,406	$ 114,235	$ 117,411	$ 120,553	$ 123,930	$ 127,513	$ 127,857	$ 133,077	$ 136,405	$ 140,601
8															
9 Operating Income	16,107	18,047	18,395	18,594	19,859	19,713	19,907	22,015	22,712	24,854	27,013	28,717	29,581	30,736	31,015
10 Interest Expense, Incl AFUDC	(2,601)	(2,345)	(2,249)	(2,858)	(4,882)	(4,916)	(4,780)	(4,612)	(4,442)	(4,254)	(4,046)	(8,668)	(7,112)	(7,747)	(7,510)
11 Interest and Other Income	664	670	714	750	749	445	410	405	414	446	521	1,054	1,028	553	598
12 Income B4 Transfer/Cap Contribution	$ 14,170	$ 16,373	$ 16,859	$ 16,487	$ 15,727	$ 15,241	$ 15,538	$ 17,808	$ 18,684	$ 21,045	$ 23,488	$ 21,104	$ 23,497	$ 23,541	$ 24,102
13															
14 Net Transfers & Contributions In (Out)	(7,937)	(8,056)	(8,403)	(8,773)	(9,114)	(9,497)	(9,906)	(10,364)	(10,799)	(11,287)	(11,796)	(12,440)	(13,041)	(13,390)	(13,736)
15															
16 Change in Net Assets	$ 6,233	$ 8,317	$ 8,457	$ 7,713	$ 6,612	$ 5,744	$ 5,631	$ 7,444	$ 7,885	$ 9,759	$ 11,691	$ 8,664	$ 10,456	$ 10,151	$ 10,367
17															
18															
19															
20 01/01 Cash Balance	$ 14,217	$ 12,734	$ 14,600	$ 15,613	$ 16,973	$ 15,534	$ 13,696	$ 13,259	$ 13,339	$ 13,839	$ 15,443	$ 18,742	$ 50,487	$ 17,034	$ 19,249
21															
22 Change in Net Assets	6,233	8,317	8,457	7,713	6,612	5,744	5,631	7,444	7,885	9,759	11,691	8,664	10,456	10,151	10,367
23 Operating & Capital Activity	(11,036)	(4,691)	(5,608)	(15,143)	(40,327)	(4,717)	(3,051)	(4,179)	(4,027)	(4,613)	(5,350)	(39,677)	(39,702)	(4,544)	(6,031)
24 Bond Principle Payments	(1,681)	(1,760)	(1,835)	(2,211)	(2,724)	(2,866)	(3,017)	(3,185)	(3,358)	(3,542)	(3,042)	(3,981)	(4,208)	(3,392)	(3,595)
25 Bond Sale Proceeds	5,000	-	-	11,000	35,000	-	-	-	-	-	-	66,740	-	-	-
26															
27 Net Changes in Cash	$ (1,484)	$ 1,867	$ 1,013	$ 1,359	$ (1,438)	$ (1,838)	$ (437)	$ 80	$ 499	$ 1,604	$ 3,299	$ 31,745	$ (33,454)	$ 2,215	$ 740
28															
29 12/31 Cash Balance	12,734	14,600	15,613	16,973	15,534	13,696	13,259	13,339	13,839	15,443	18,742	50,487	17,034	19,249	19,989
30 Reserve Minimum	10,118	10,116	10,406	11,533	13,060	11,518	11,828	12,415	13,196	14,008	15,298	17,398	17,363	16,224	16,964
31 Excess (Deficit) from Minimum	$ 2,615	$ 4,485	$ 5,207	$ 5,440	$ 2,475	$ 2,178	$ 1,431	$ 925	$ 643	$ 1,435	$ 3,444	$ 33,089	$ (329)	$ 3,025	$ 3,025
32															
33 Rate Change	3.0%	2.0%	1.0%	1.0%	3.0%	1.0%	1.0%	2.0%	1.0%	2.0%	2.0%	3.0%	2.0%	0.0%	0.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 3,802	$ 4,089	$ 4,659	$ 3,640	$ 4,391	$ 4,347	$ 3,892	$ 4,147	$ 4,201	$ 4,477	$ 5,000	$ 6,882	$ 6,946	$ 5,829	$ 6,999
37 Transmission Line Additions	-	-	-	11,000	11,000	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	-	-	-	-	-	-	33,370	33,370	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	-	-	-	-	24,000	-	-	-	-	-	-	-	-	-	-
41 Other	12,279	6,886	7,355	7,671	8,829	8,305	8,560	9,035	9,475	10,000	10,617	12,474	13,012	12,411	13,317
42 Total Capital Expenditures	$ 16,080	$ 10,976	$ 12,013	$ 22,311	$ 48,219	$ 12,652	$ 12,452	$ 13,181	$ 13,676	$ 14,477	$ 15,617	$ 52,725	$ 53,328	$ 18,240	$ 20,315
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ 5,000	$ -	$ -	$ 11,000	$ 35,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 66,740	$ -	$ -	$ -
47 Debt Service Payments	$ 4,183	$ 4,187	$ 4,183	$ 5,189	$ 7,868	$ 7,867	$ 7,866	$ 7,872	$ 7,875	$ 7,878	$ 7,184	$ 12,301	$ 12,307	$ 11,255	$ 11,255
48 Debt Outstanding	$ 48,369	$ 46,610	$ 44,775	$ 53,564	$ 85,840	$ 82,975	$ 79,957	$ 76,772	$ 73,415	$ 69,873	$ 66,831	$ 129,590	$ 125,382	$ 121,990	$ 118,394
49 Debt Service Coverage Ratio	5.3	6.1	6.3	5.3	3.8	3.7	3.8	4.1	4.2	4.6	5.4	3.3	4.0	4.1	4.2

Rochester Public Utilities
Financial Model Results
Scenario: Aggressive DSM, Coal & Gas Mix
Scenario Description: Recommended plan adjuste
All dollar values in $1,000s

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 Sales of Electricity - Retail	$ 154,931	$ 160,308	$ 169,477	$ 177,433	$ 188,115	$ 194,648	$ 203,787	$ 215,550	$ 228,425	$ 238,814	$ 250,151	$ 264,376	$ 276,698	$ 292,436	$ 309,069
2 Other Revenues	23,254	24,063	24,902	25,728	26,546	35,261	35,789	36,437	37,150	37,650	38,201	38,886	39,824	40,577	41,486
3 Total Operating Revenues	$ 178,184	$ 184,371	$ 194,380	$ 203,160	$ 214,661	$ 229,909	$ 239,576	$ 251,987	$ 265,575	$ 276,465	$ 288,352	$ 303,262	$ 316,522	$ 333,012	$ 350,555
4															
5 Power Supply Costs	85,190	87,633	90,856	94,450	98,729	105,134	109,618	114,733	120,492	125,399	132,017	139,321	147,249	156,456	166,210
6 Net Other Operating Expenses	60,453	63,535	66,245	70,283	74,893	79,699	83,199	86,161	91,086	97,478	101,393	106,224	110,972	117,289	122,825
7 Total Operating Expenses	$ 145,643	$ 151,168	$ 157,101	$ 164,733	$ 173,622	$ 184,833	$ 192,817	$ 200,894	$ 211,578	$ 222,877	$ 233,410	$ 245,545	$ 258,221	$ 273,746	$ 289,035
8															
9 Operating Income	32,541	33,202	37,279	38,428	41,040	45,076	46,759	51,093	53,997	53,587	54,942	57,717	58,301	59,267	61,520
10 Interest Expense, Incl AFUDC	(7,295)	(7,077)	(6,774)	(11,104)	(9,556)	(9,972)	(9,595)	(13,215)	(11,633)	(11,975)	(11,467)	(10,943)	(10,596)	(10,262)	(9,773)
11 Interest and Other Income	628	673	732	1,207	1,198	775	852	1,307	1,324	983	1,027	1,043	1,069	1,104	1,123
12 Income B4 Transfer/Cap Contribution	$ 25,875	$ 26,799	$ 31,237	$ 28,530	$ 32,682	$ 35,880	$ 38,016	$ 39,185	$ 43,688	$ 42,595	$ 44,503	$ 47,818	$ 48,774	$ 50,109	$ 52,870
13															
14 Net Transfers & Contributions In (Out)	(14,485)	(15,215)	(16,013)	(16,854)	(17,791)	(18,688)	(19,668)	(20,711)	(21,852)	(22,964)	(24,182)	(25,441)	(26,767)	(28,161)	(29,628)
15															
16 Change in Net Assets	$ 11,390	$ 11,584	$ 15,223	$ 11,676	$ 14,891	$ 17,192	$ 18,348	$ 18,474	$ 21,836	$ 19,631	$ 20,322	$ 22,376	$ 22,007	$ 21,948	$ 23,242
17															
18															
19															
20 01/01 Cash Balance	$ 19,989	$ 21,246	$ 22,962	$ 25,124	$ 54,104	$ 24,557	$ 26,360	$ 29,598	$ 56,217	$ 30,713	$ 33,821	$ 33,650	$ 34,871	$ 35,326	$ 37,176
21															
22 Change in Net Assets	11,390	11,584	15,223	11,676	14,891	17,192	18,348	18,474	21,836	19,631	20,322	22,376	22,007	21,948	23,242
23 Operating & Capital Activity	(6,321)	(5,828)	(8,777)	(40,826)	(38,834)	(9,443)	(8,801)	(40,258)	(40,546)	(9,314)	(12,846)	(15,503)	(15,533)	(13,687)	(17,012)
24 Bond Principle Payments	(3,812)	(4,039)	(4,285)	(5,277)	(5,604)	(5,946)	(6,309)	(7,341)	(6,794)	(7,208)	(7,647)	(5,652)	(6,019)	(6,410)	(6,827)
25 Bond Sale Proceeds	-	-	-	63,407	-	-	-	55,744	-	-	-	-	-	-	-
26															
27 Net Changes in Cash	$ 1,257	$ 1,717	$ 2,161	$ 28,980	$ (29,547)	$ 1,803	$ 3,238	$ 26,619	$ (25,504)	$ 3,109	$ (171)	$ 1,222	$ 454	$ 1,850	$ (597)
28															
29 12/31 Cash Balance	21,246	22,962	25,124	54,104	24,557	26,360	29,598	56,217	30,713	33,821	33,650	34,871	35,326	37,176	36,579
30 Reserve Minimum	17,824	19,047	20,110	22,485	23,700	23,393	24,871	27,136	28,016	28,293	29,247	30,269	31,426	33,662	35,699
31 Excess (Deficit) from Minimum	$ 3,421	$ 3,916	$ 5,013	$ 31,619	$ 857	$ 2,967	$ 4,727	$ 29,081	$ 2,697	$ 5,528	$ 4,403	$ 4,603	$ 3,900	$ 3,514	$ 880
32															
33 Rate Change	1.0%	1.0%	3.0%	2.0%	3.0%	1.0%	2.0%	3.0%	3.0%	2.0%	2.0%	3.0%	2.0%	3.0%	3.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 7,061	$ 6,742	$ 8,704	$ 9,073	$ 7,818	$ 9,005	$ 9,517	$ 10,767	$ 11,366	$ 9,554	$ 11,858	$ 13,780	$ 13,265	$ 11,596	$ 14,038
37 Transmission Line Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	-	-	27,872	27,872	-	-	-	-	-	-
39 Baseload Generation Additions	-	-	-	31,704	31,704	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41 Other	13,940	14,490	15,715	17,320	17,712	18,040	19,011	20,930	22,015	21,775	23,440	25,052	26,035	26,754	28,691
42 Total Capital Expenditures	$ 21,001	$ 21,232	$ 24,418	$ 58,097	$ 57,233	$ 27,045	$ 28,528	$ 59,569	$ 61,253	$ 31,329	$ 35,298	$ 38,832	$ 39,300	$ 38,350	$ 42,729
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ -	$ -	$ -	$ 63,407	$ -	$ -	$ -	$ 55,744	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47 Debt Service Payments	$ 11,255	$ 11,252	$ 11,254	$ 16,108	$ 16,112	$ 16,112	$ 16,111	$ 20,380	$ 19,381	$ 19,380	$ 19,378	$ 16,915	$ 16,915	$ 16,915	$ 16,915
48 Debt Outstanding	$ 114,582	$ 110,543	$ 106,258	$ 164,388	$ 158,784	$ 152,838	$ 146,529	$ 194,932	$ 188,138	$ 180,930	$ 173,283	$ 167,632	$ 161,612	$ 155,202	$ 148,375
49 Debt Service Coverage Ratio	4.4	4.5	4.9	3.5	4.1	4.1	4.3	3.6	4.2	4.1	4.2	5.0	5.1	5.2	5.4

Rochester Public Utilities
Financial Model Results
Scenario: Aggressive DSM, All Gas
Scenario Description: Recommended plan adjusted by using the aggressive demand side management results with SLP operating on natural gas and the coal unit replaced with gas-fired capacity
All dollar values in $1,000s

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 Sales of Electricity - Retail	$ 109,247	$ 110,941	$ 112,900	$ 115,002	$ 118,918	$ 122,112	$ 124,268	$ 129,360	$ 131,519	$ 134,097	$ 138,092	$ 144,843	$ 149,585	$ 153,533	$ 159,011
2 Other Revenues	19,619	20,866	21,386	20,929	21,526	25,428	23,330	24,072	24,809	25,582	26,392	20,717	20,959	21,703	22,483
3 Total Operating Revenues	$ 128,866	$ 131,806	$ 134,286	$ 135,932	$ 140,445	$ 147,540	$ 147,598	$ 153,432	$ 156,328	$ 159,679	$ 164,484	$ 165,560	$ 170,545	$ 175,236	$ 181,495
4															
5 Power Supply Costs	86,254	82,792	84,298	84,451	86,019	92,626	88,749	90,565	92,205	94,111	96,432	89,337	91,648	92,947	95,425
6 Net Other Operating Expenses	27,019	29,418	31,155	32,569	34,698	37,245	38,889	40,706	42,634	44,564	46,578	48,029	51,427	54,011	56,348
7 Total Operating Expenses	$ 113,272	$ 112,209	$ 115,453	$ 117,020	$ 120,717	$ 129,872	$ 127,637	$ 131,271	$ 134,839	$ 138,674	$ 143,010	$ 137,366	$ 143,075	$ 146,958	$ 151,772
8															
9 Operating Income	15,594	19,597	18,832	18,911	19,728	17,668	19,961	22,161	21,489	21,004	21,474	28,194	27,470	28,278	29,722
10 Interest Expense, Incl AFUDC	(3,201)	(3,007)	(2,926)	(3,549)	(4,388)	(4,354)	(4,251)	(4,120)	(3,987)	(3,840)	(3,675)	(8,298)	(6,743)	(7,379)	(7,142)
11 Interest and Other Income	627	615	684	736	768	479	460	507	557	583	580	1,071	1,057	566	599
12 Income B4 Transfer/Cap Contribution	$ 13,019	$ 17,204	$ 16,591	$ 16,098	$ 16,109	$ 13,792	$ 16,169	$ 18,548	$ 18,059	$ 17,747	$ 18,379	$ 20,968	$ 21,785	$ 21,465	$ 23,179
13															
14 Net Transfers & Contributions In (Out)	(7,937)	(8,056)	(8,198)	(8,351)	(8,675)	(9,040)	(9,199)	(9,624)	(9,784)	(9,976)	(10,426)	(10,995)	(11,526)	(11,835)	(12,444)
15															
16 Change in Net Assets	$ 5,083	$ 9,149	$ 8,393	$ 7,748	$ 7,433	$ 4,753	$ 6,970	$ 8,925	$ 8,276	$ 7,771	$ 7,952	$ 9,973	$ 10,258	$ 9,630	$ 10,735
17															
18															
19															
20 01/01 Cash Balance	$ 14,217	$ 10,302	$ 13,385	$ 14,872	$ 16,800	$ 16,994	$ 14,458	$ 15,722	$ 17,588	$ 18,989	$ 19,298	$ 18,764	$ 51,582	$ 17,851	$ 19,319
21															
22 Change in Net Assets	5,083	9,149	8,393	7,748	7,433	4,753	6,970	8,925	8,276	7,771	7,952	9,973	10,258	9,630	10,735
23 Operating & Capital Activity	(22,515)	(4,516)	(5,294)	(14,847)	(20,000)	(4,940)	(3,238)	(4,460)	(4,140)	(4,585)	(5,456)	(39,926)	(39,795)	(4,784)	(6,450)
24 Bond Principle Payments	(1,484)	(1,550)	(1,612)	(1,973)	(2,239)	(2,349)	(2,468)	(2,599)	(2,734)	(2,877)	(3,030)	(3,969)	(4,194)	(3,378)	(3,580)
25 Bond Sale Proceeds	15,000	-	-	11,000	15,000	-	-	-	-	-	-	66,740	-	-	-
26															
27 Net Changes in Cash	$ (3,916)	$ 3,083	$ 1,487	$ 1,928	$ 195	$ (2,536)	$ 1,264	$ 1,865	$ 1,401	$ 309	$ (534)	$ 32,818	$ (33,731)	$ 1,468	$ 705
28															
29 12/31 Cash Balance	10,302	13,385	14,872	16,800	16,994	14,458	15,722	17,588	18,989	19,298	18,764	51,582	17,851	19,319	20,024
30 Reserve Minimum	11,180	10,472	10,758	11,745	12,231	11,978	12,115	12,755	13,590	14,610	15,957	17,723	17,690	16,551	17,304
31 Excess (Deficit) from Minimum	$ (878)	$ 2,913	$ 4,114	$ 5,055	$ 4,764	$ 2,480	$ 3,607	$ 4,833	$ 5,399	$ 4,688	$ 2,807	$ 33,859	$ 160	$ 2,768	$ 2,720
32															
33 Rate Change	20.0%	2.0%	0.0%	0.0%	2.0%	1.0%	0.0%	2.0%	0.0%	0.0%	1.0%	2.0%	1.0%	0.0%	1.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 3,802	$ 4,089	$ 4,659	$ 3,640	$ 4,391	$ 4,347	$ 3,892	$ 4,147	$ 4,201	$ 4,477	$ 5,000	$ 6,882	$ 6,946	$ 5,829	$ 6,999
37 Transmission Line Additions	-	-	-	11,000	11,000	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	-	-	-	-	-	-	33,370	33,370	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	10,000	-	-	-	4,000	-	-	-	-	-	-	-	-	-	-
41 Other	12,529	6,886	7,355	7,671	8,329	8,305	8,560	9,035	9,475	10,000	10,617	12,474	13,012	12,411	13,317
42 Total Capital Expenditures	$ 26,330	$ 10,976	$ 12,013	$ 22,311	$ 27,719	$ 12,652	$ 12,452	$ 13,181	$ 13,676	$ 14,477	$ 15,617	$ 52,725	$ 53,328	$ 18,240	$ 20,315
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ 15,000	$ -	$ -	$ 11,000	$ 15,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 66,740	$ -	$ -	$ -
47 Debt Service Payments	$ 4,636	$ 4,640	$ 4,636	$ 5,642	$ 6,789	$ 6,788	$ 6,788	$ 6,794	$ 6,796	$ 6,800	$ 6,801	$ 11,918	$ 11,924	$ 10,872	$ 10,872
48 Debt Outstanding	$ 58,566	$ 57,016	$ 55,404	$ 64,431	$ 77,193	$ 74,843	$ 72,376	$ 69,777	$ 67,043	$ 64,165	$ 61,135	$ 123,907	$ 119,712	$ 116,334	$ 112,754
49 Debt Service Coverage Ratio	4.8	5.9	5.8	4.9	4.3	4.0	4.4	4.8	4.7	4.7	4.9	3.4	3.9	4.0	4.2

Rochester Public Utilities
Financial Model Results
Scenario: Aggressive DSM, All Gas
Scenario Description: Recommended plan adjuste
All dollar values in $1,000s

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 Sales of Electricity - Retail	$ 165,153	$ 172,577	$ 178,905	$ 189,139	$ 200,527	$ 209,544	$ 221,534	$ 234,322	$ 248,318	$ 262,157	$ 277,294	$ 293,062	$ 309,729	$ 324,167	$ 339,279
2 Other Revenues	23,292	24,105	24,939	25,769	26,589	27,411	28,327	29,320	30,382	31,443	32,550	33,701	34,941	36,185	37,512
3 Total Operating Revenues	$ 188,444	$ 196,682	$ 203,844	$ 214,908	$ 227,116	$ 236,956	$ 249,862	$ 263,642	$ 278,700	$ 293,600	$ 309,844	$ 326,763	$ 344,670	$ 360,351	$ 376,791
4															
5 Power Supply Costs	98,375	101,624	105,840	110,732	116,714	121,946	128,405	135,472	143,381	150,938	160,197	169,974	180,136	191,835	204,074
6 Net Other Operating Expenses	59,167	62,229	64,872	68,601	72,887	76,242	79,716	82,626	87,505	93,890	97,811	102,616	107,339	113,589	119,051
7 Total Operating Expenses	$ 157,542	$ 163,853	$ 170,712	$ 179,334	$ 189,601	$ 198,188	$ 208,121	$ 218,099	$ 230,886	$ 244,828	$ 258,008	$ 272,590	$ 287,475	$ 305,424	$ 323,125
8															
9 Operating Income	30,902	32,829	33,132	35,575	37,515	38,767	41,741	45,543	47,814	48,772	51,836	54,173	57,195	54,927	53,666
10 Interest Expense, Incl AFUDC	(6,928)	(6,711)	(6,410)	(7,978)	(7,222)	(7,193)	(6,851)	(10,507)	(8,964)	(9,347)	(8,882)	(8,405)	(8,107)	(7,826)	(7,394)
11 Interest and Other Income	627	685	727	904	927	793	849	1,272	1,247	873	930	984	1,082	1,189	1,193
12 Income B4 Transfer/Cap Contribution	$ 24,601	$ 26,803	$ 27,448	$ 28,501	$ 31,220	$ 32,367	$ 35,739	$ 36,309	$ 40,098	$ 40,299	$ 43,884	$ 46,753	$ 50,170	$ 48,291	$ 47,465
13															
14 Net Transfers & Contributions In (Out)	(13,123)	(13,784)	(14,507)	(15,269)	(16,118)	(16,930)	(17,819)	(18,763)	(19,796)	(20,805)	(21,907)	(23,049)	(24,249)	(25,513)	(26,842)
15															
16 Change in Net Assets	$ 11,478	$ 13,019	$ 12,941	$ 13,233	$ 15,102	$ 15,437	$ 17,920	$ 17,546	$ 20,301	$ 19,494	$ 21,977	$ 23,704	$ 25,921	$ 22,778	$ 20,623
17															
18															
19															
20 01/01 Cash Balance	$ 20,024	$ 21,129	$ 23,852	$ 23,864	$ 35,526	$ 25,352	$ 26,739	$ 29,021	$ 54,506	$ 27,361	$ 29,991	$ 31,099	$ 33,534	$ 37,532	$ 40,539
21															
22 Change in Net Assets	11,478	13,019	12,941	13,233	15,102	15,437	17,920	17,546	20,301	19,494	21,977	23,704	25,921	22,778	20,623
23 Operating & Capital Activity	(6,577)	(6,274)	(8,662)	(22,054)	(20,163)	(8,628)	(9,885)	(41,057)	(41,284)	(10,328)	(13,938)	(16,380)	(16,716)	(14,226)	(17,486)
24 Bond Principle Payments	(3,796)	(4,021)	(4,267)	(4,816)	(5,113)	(5,423)	(5,753)	(6,748)	(6,162)	(6,536)	(6,931)	(4,889)	(5,207)	(5,545)	(5,906)
25 Bond Sale Proceeds	-	-	-	25,300	-	-	-	55,744	-	-	-	-	-	-	-
26															
27 Net Changes in Cash	$ 1,105	$ 2,723	$ 12	$ 11,662	$ (10,174)	$ 1,387	$ 2,282	$ 25,485	$ (27,145)	$ 2,630	$ 1,108	$ 2,435	$ 3,998	$ 3,007	$ (2,769)
28															
29 12/31 Cash Balance	21,129	23,852	23,864	35,526	25,352	26,739	29,021	54,506	27,361	29,991	31,099	33,534	37,532	40,539	37,770
30 Reserve Minimum	18,156	19,381	20,245	21,603	22,945	23,509	25,053	27,357	28,258	28,602	29,654	30,766	32,079	34,460	36,324
31 Excess (Deficit) from Minimum	$ 2,973	$ 4,471	$ 3,620	$ 13,924	$ 2,408	$ 3,230	$ 3,968	$ 27,149	$ (897)	$ 1,389	$ 1,445	$ 2,769	$ 5,453	$ 6,079	$ 1,446
32															
33 Rate Change	1.0%	2.0%	1.0%	3.0%	3.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.0%	2.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 7,061	$ 6,742	$ 8,704	$ 9,073	$ 7,818	$ 9,005	$ 9,517	$ 10,767	$ 11,366	$ 9,554	$ 11,858	$ 13,780	$ 13,265	$ 11,596	$ 14,038
37 Transmission Line Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	12,650	12,650	-	-	27,872	27,872	-	-	-	-	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41 Other	13,940	14,490	15,715	16,844	17,236	18,040	19,011	20,930	22,015	21,775	23,440	25,052	26,035	26,754	28,691
42 Total Capital Expenditures	$ 21,001	$ 21,232	$ 24,418	$ 38,567	$ 37,704	$ 27,045	$ 28,528	$ 59,569	$ 61,253	$ 31,329	$ 35,298	$ 38,832	$ 39,300	$ 38,350	$ 42,729
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ -	$ -	$ -	$ 25,300	$ -	$ -	$ -	$ 55,744	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47 Debt Service Payments	$ 10,872	$ 10,869	$ 10,871	$ 12,807	$ 12,811	$ 12,811	$ 12,810	$ 17,079	$ 16,080	$ 16,079	$ 16,077	$ 13,614	$ 13,614	$ 13,614	$ 13,614
48 Debt Outstanding	$ 108,958	$ 104,937	$ 100,670	$ 121,154	$ 116,041	$ 110,617	$ 104,865	$ 153,861	$ 147,698	$ 141,163	$ 134,232	$ 129,343	$ 124,136	$ 118,591	$ 112,685
49 Debt Service Coverage Ratio	4.3	4.6	4.7	4.2	4.6	4.7	5.0	3.9	4.7	4.5	4.8	6.0	6.2	6.1	6.1

Rochester Public Utilities
Financial Model Results
Scenario: Normal DSM, Coal & Gas Mix
Scenario Description: Recommended plan adjusted by using the normal demand side management forecast with SLP operating on coal and adjustments to the new resources.
All dollar values in $1,000s

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 Sales of Electricity - Retail	$ 93,770	$ 93,491	$ 95,323	$ 99,323	$ 104,010	$ 108,272	$ 111,604	$ 115,257	$ 121,041	$ 127,358	$ 131,403	$ 135,062	$ 138,038	$ 144,448	$ 149,533
2 Other Revenues	19,211	20,865	21,378	20,920	21,510	25,402	23,412	24,141	24,879	25,649	26,447	20,784	20,877	21,630	22,400
3 Total Operating Revenues	$ 112,981	$ 114,357	$ 116,702	$ 120,243	$ 125,520	$ 133,673	$ 135,015	$ 139,398	$ 145,920	$ 153,008	$ 157,850	$ 155,846	$ 158,915	$ 166,078	$ 171,933
4															
5 Power Supply Costs	69,442	68,104	69,292	70,186	71,500	76,034	75,345	76,820	78,201	79,659	81,279	79,160	80,691	82,517	84,445
6 Net Other Operating Expenses	27,177	29,413	30,688	31,815	34,413	36,930	38,605	40,409	42,366	45,300	48,176	50,217	52,835	54,456	57,120
7 Total Operating Expenses	$ 96,619	$ 97,517	$ 99,980	$ 102,001	$ 105,913	$ 112,964	$ 113,950	$ 117,228	$ 120,567	$ 124,959	$ 129,455	$ 129,377	$ 133,527	$ 136,973	$ 141,566
8															
9 Operating Income	16,362	16,840	16,722	18,242	19,608	20,709	21,065	22,170	25,353	28,049	28,395	26,469	25,389	29,104	30,367
10 Interest Expense, Incl AFUDC	(2,601)	(2,345)	(2,248)	(2,856)	(4,879)	(4,913)	(4,777)	(4,610)	(4,439)	(8,802)	(7,258)	(7,820)	(7,643)	(7,364)	(7,163)
11 Interest and Other Income	668	665	676	687	681	390	391	413	468	993	1,012	542	510	486	497
12 Income B4 Transfer/Cap Contribution	$ 14,429	$ 15,160	$ 15,150	$ 16,074	$ 15,409	$ 16,187	$ 16,679	$ 17,972	$ 21,382	$ 20,240	$ 22,150	$ 19,191	$ 18,255	$ 22,226	$ 23,701
13															
14 Net Transfers & Contributions In (Out)	(7,937)	(7,870)	(8,025)	(8,404)	(8,757)	(9,162)	(9,585)	(10,047)	(10,501)	(10,997)	(11,516)	(11,842)	(12,105)	(12,734)	(13,383)
15															
16 Change in Net Assets	$ 6,492	$ 7,289	$ 7,124	$ 7,670	$ 6,652	$ 7,025	$ 7,094	$ 7,925	$ 10,881	$ 9,243	$ 10,634	$ 7,349	$ 6,150	$ 9,492	$ 10,319
17															
18															
19															
20 01/01 Cash Balance	$ 14,217	$ 12,981	$ 14,000	$ 13,701	$ 14,778	$ 13,250	$ 12,387	$ 13,257	$ 13,831	$ 16,892	$ 48,332	$ 18,109	$ 17,474	$ 15,988	$ 15,908
21															
22 Change in Net Assets	6,492	7,289	7,124	7,670	6,652	7,025	7,094	7,925	10,881	9,243	10,634	7,349	6,150	9,492	10,319
23 Operating & Capital Activity	(11,048)	(4,510)	(5,589)	(15,382)	(40,456)	(5,023)	(3,207)	(4,166)	(4,463)	(36,433)	(37,040)	(3,950)	(3,371)	(6,118)	(5,828)
24 Bond Principle Payments	(1,681)	(1,760)	(1,835)	(2,211)	(2,724)	(2,866)	(3,017)	(3,185)	(3,358)	(4,270)	(3,817)	(4,035)	(4,265)	(3,453)	(3,660)
25 Bond Sale Proceeds	5,000	-	-	11,000	35,000	-	-	-	-	62,900	-	-	-	-	-
26															
27 Net Changes in Cash	$ (1,236)	$ 1,019	$ (300)	$ 1,077	$ (1,528)	$ (864)	$ 870	$ 574	$ 3,061	$ 31,440	$ (30,223)	$ (635)	$ (1,486)	$ (79)	$ 831
28															
29 12/31 Cash Balance	12,981	14,000	13,701	14,778	13,250	12,387	13,257	13,831	16,892	48,332	18,109	17,474	15,988	15,908	16,739
30 Reserve Minimum	10,182	10,191	10,453	11,568	13,088	11,576	11,999	12,745	13,915	16,451	16,860	15,077	15,616	16,304	17,140
31 Excess (Deficit) from Minimum	$ 2,799	$ 3,809	$ 3,248	$ 3,210	$ 162	$ 811	$ 1,258	$ 1,086	$ 2,977	$ 31,882	$ 1,249	$ 2,396	$ 371	$ (396)	$ (401)
32															
33 Rate Change	3.0%	0.0%	0.0%	2.0%	3.0%	2.0%	1.0%	1.0%	3.0%	3.0%	1.0%	0.0%	0.0%	2.0%	1.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 3,802	$ 4,091	$ 4,710	$ 3,722	$ 4,480	$ 4,473	$ 4,000	$ 4,235	$ 4,327	$ 4,901	$ 6,424	$ 6,918	$ 5,460	$ 6,782	$ 6,670
37 Transmission Line Additions	-	-	-	11,000	11,000	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	-	-	-	-	31,450	31,450	-	-	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	-	-	-	-	24,000	-	-	-	-	-	-	-	-	-	-
41 Other	12,279	6,886	7,368	7,692	8,851	8,337	8,586	9,054	9,504	10,898	11,796	11,641	11,752	12,671	13,216
42 Total Capital Expenditures	$ 16,080	$ 10,977	$ 12,078	$ 22,414	$ 48,331	$ 12,810	$ 12,587	$ 13,289	$ 13,831	$ 47,249	$ 49,670	$ 18,560	$ 17,212	$ 19,453	$ 19,886
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ 5,000	$ -	$ -	$ 11,000	$ 35,000	$ -	$ -	$ -	$ -	$ 62,900	$ -	$ -	$ -	$ -	$ -
47 Debt Service Payments	$ 4,183	$ 4,187	$ 4,183	$ 5,189	$ 7,868	$ 7,867	$ 7,866	$ 7,872	$ 7,875	$ 12,695	$ 12,001	$ 12,007	$ 12,013	$ 10,961	$ 10,961
48 Debt Outstanding	$ 48,369	$ 46,610	$ 44,775	$ 53,564	$ 85,840	$ 82,975	$ 79,957	$ 76,772	$ 73,415	$ 132,045	$ 128,228	$ 124,193	$ 119,928	$ 116,476	$ 112,816
49 Debt Service Coverage Ratio	5.4	5.8	5.9	5.2	3.8	3.8	3.9	4.1	4.6	3.1	3.8	3.4	3.4	4.0	4.2

Rochester Public Utilities
Financial Model Results
Scenario: Normal DSM, Coal & Gas Mix
Scenario Description: Recommended plan adjuste
All dollar values in $1,000s

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 Sales of Electricity - Retail	$ 158,311	$ 166,813	$ 174,644	$ 179,088	$ 186,186	$ 196,281	$ 207,513	$ 215,130	$ 227,982	$ 240,460	$ 251,876	$ 266,201	$ 281,342	$ 297,345	$ 311,209
2 Other Revenues	23,210	24,015	24,815	34,067	34,226	34,679	35,295	35,940	36,578	37,089	37,673	38,412	39,393	40,137	41,042
3 Total Operating Revenues	$ 181,520	$ 190,828	$ 199,459	$ 213,155	$ 220,412	$ 230,960	$ 242,809	$ 251,070	$ 264,560	$ 277,549	$ 289,549	$ 304,613	$ 320,735	$ 337,482	$ 352,250
4															
5 Power Supply Costs	86,934	89,766	93,185	100,022	103,673	107,611	112,404	117,090	122,764	128,637	135,699	143,429	151,743	161,315	171,407
6 Net Other Operating Expenses	59,981	63,326	67,051	72,220	75,370	79,812	84,048	87,403	91,793	96,072	100,071	105,462	110,402	115,741	121,356
7 Total Operating Expenses	$ 146,915	$ 153,092	$ 160,236	$ 172,242	$ 179,043	$ 187,422	$ 196,452	$ 204,493	$ 214,557	$ 224,709	$ 235,770	$ 248,891	$ 262,145	$ 277,057	$ 292,762
8															
9 Operating Income	34,606	37,736	39,223	40,913	41,369	43,538	46,357	46,577	50,003	52,840	53,779	55,723	58,590	60,425	59,488
10 Interest Expense, Incl AFUDC	(6,946)	(10,997)	(9,495)	(9,978)	(9,599)	(13,095)	(11,581)	(11,795)	(11,375)	(10,893)	(10,373)	(9,910)	(9,579)	(9,099)	(8,598)
11 Interest and Other Income	571	1,088	1,120	746	834	1,269	1,280	864	864	921	929	946	1,059	1,178	1,189
12 Income B4 Transfer/Cap Contribution	$ 28,231	$ 27,828	$ 30,848	$ 31,682	$ 32,604	$ 31,712	$ 36,056	$ 35,646	$ 39,492	$ 42,868	$ 44,335	$ 46,759	$ 50,070	$ 52,505	$ 52,079
13															
14 Net Transfers & Contributions In (Out)	(14,106)	(14,795)	(15,571)	(15,973)	(16,861)	(17,693)	(18,622)	(19,599)	(20,679)	(21,710)	(22,861)	(24,052)	(25,305)	(26,623)	(28,010)
15															
16 Change in Net Assets	$ 14,125	$ 13,033	$ 15,277	$ 15,709	$ 15,743	$ 14,019	$ 17,434	$ 16,047	$ 18,813	$ 21,158	$ 21,474	$ 22,707	$ 24,765	$ 25,882	$ 24,069
17															
18															
19															
20 01/01 Cash Balance	$ 16,739	$ 20,764	$ 50,685	$ 22,880	$ 26,127	$ 28,625	$ 54,679	$ 29,400	$ 27,369	$ 29,350	$ 31,159	$ 29,856	$ 32,250	$ 37,310	$ 40,061
21															
22 Change in Net Assets	14,125	13,033	15,277	15,709	15,743	14,019	17,434	16,047	18,813	21,158	21,474	22,707	24,765	25,882	24,069
23 Operating & Capital Activity	(6,220)	(38,075)	(37,982)	(7,052)	(7,499)	(34,309)	(35,588)	(10,515)	(9,800)	(11,888)	(14,861)	(14,374)	(13,380)	(16,395)	(18,928)
24 Bond Principle Payments	(3,881)	(4,804)	(5,100)	(5,411)	(5,746)	(6,712)	(7,125)	(7,564)	(7,032)	(7,461)	(7,916)	(5,939)	(6,325)	(6,736)	(7,174)
25 Bond Sale Proceeds	-	59,767	-	-	-	53,056	-	-	-	-	-	-	-	-	-
26															
27 Net Changes in Cash	$ 4,025	$ 29,921	$ (27,805)	$ 3,247	$ 2,498	$ 26,054	$ (25,279)	$ (2,031)	$ 1,981	$ 1,809	$ (1,303)	$ 2,394	$ 5,060	$ 2,751	$ (2,033)
28															
29 12/31 Cash Balance	20,764	50,685	22,880	26,127	28,625	54,679	29,400	27,369	29,350	31,159	29,856	32,250	37,310	40,061	38,028
30 Reserve Minimum	18,506	20,937	21,468	21,383	22,706	25,372	26,293	25,408	27,097	28,658	28,976	30,156	32,243	34,178	35,411
31 Excess (Deficit) from Minimum	$ 2,258	$ 29,748	$ 1,413	$ 4,744	$ 5,919	$ 29,307	$ 3,107	$ 1,960	$ 2,253	$ 2,501	$ 880	$ 2,094	$ 5,067	$ 5,883	$ 2,617
32															
33 Rate Change	3.0%	3.0%	2.0%	0.0%	1.0%	3.0%	3.0%	1.0%	3.0%	3.0%	2.0%	3.0%	3.0%	3.0%	2.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 6,652	$ 8,248	$ 8,759	$ 7,321	$ 8,944	$ 9,005	$ 10,351	$ 10,797	$ 9,441	$ 11,215	$ 13,347	$ 12,774	$ 11,137	$ 13,509	$ 15,685
37 Transmission Line Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	26,528	26,528	-	-	-	-	-	-	-	-
39 Baseload Generation Additions	-	29,884	29,884	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41 Other	13,817	15,653	16,469	16,026	17,228	18,695	19,901	20,234	20,769	22,234	23,851	24,761	25,428	27,283	29,145
42 Total Capital Expenditures	$ 20,468	$ 53,785	$ 55,112	$ 23,347	$ 26,172	$ 54,228	$ 56,779	$ 31,031	$ 30,210	$ 33,449	$ 37,198	$ 37,535	$ 36,565	$ 40,792	$ 44,831
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ -	$ 59,767	$ -	$ -	$ -	$ 53,056	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47 Debt Service Payments	$ 10,961	$ 15,534	$ 15,537	$ 15,535	$ 15,539	$ 19,602	$ 19,601	$ 19,601	$ 18,602	$ 18,601	$ 18,599	$ 16,137	$ 16,137	$ 16,137	$ 16,137
48 Debt Outstanding	$ 108,935	$ 163,898	$ 158,798	$ 153,388	$ 147,642	$ 193,986	$ 186,861	$ 179,297	$ 172,266	$ 164,805	$ 156,888	$ 150,949	$ 144,625	$ 137,888	$ 130,715
49 Debt Service Coverage Ratio	4.6	3.5	4.0	3.9	4.0	3.3	3.7	3.6	4.0	4.2	4.3	5.1	5.3	5.5	5.6

Rochester Public Utilities
Financial Model Results
Scenario: Normal DSM, All Gas
Scenario Description: Recommenced plan adjusted by using the normal demand side management forecast with SLP operating on natural gas and the coal unit replaced with gas-fired capacity
All dollar values in $1,000s

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 Sales of Electricity - Retail	$ 110,157	$ 109,830	$ 111,982	$ 114,393	$ 116,302	$ 121,067	$ 124,793	$ 128,878	$ 132,718	$ 135,577	$ 141,267	$ 146,653	$ 152,883	$ 156,845	$ 160,758
2 Other Revenues	19,625	20,861	21,378	20,922	21,510	25,411	23,309	24,043	24,778	25,542	26,348	20,677	20,923	21,663	22,430
3 Total Operating Revenues	$ 129,782	$ 130,690	$ 133,360	$ 135,315	$ 137,812	$ 146,478	$ 148,102	$ 152,920	$ 157,496	$ 161,119	$ 167,615	$ 167,330	$ 173,806	$ 178,508	$ 183,188
4															
5 Power Supply Costs	86,254	82,862	84,475	84,786	86,525	93,377	89,704	91,682	93,567	95,591	98,056	91,065	93,321	94,498	97,127
6 Net Other Operating Expenses	26,837	29,112	30,538	31,640	33,744	36,264	37,926	39,715	41,641	43,458	45,254	48,017	51,748	53,787	56,421
7 Total Operating Expenses	$ 113,091	$ 111,974	$ 115,013	$ 116,425	$ 120,268	$ 129,641	$ 127,630	$ 131,397	$ 135,208	$ 139,048	$ 143,310	$ 139,082	$ 145,069	$ 148,286	$ 153,548
8															
9 Operating Income	16,691	18,716	18,347	18,890	17,544	16,838	20,472	21,523	22,287	22,071	24,305	28,248	28,737	30,222	29,640
10 Interest Expense, Incl AFUDC	(3,201)	(3,007)	(2,924)	(3,546)	(4,385)	(4,351)	(4,248)	(4,117)	(3,984)	(3,828)	(3,632)	(8,297)	(6,790)	(7,350)	(7,154)
11 Interest and Other Income	642	638	695	741	747	418	388	430	473	505	514	1,015	1,042	601	652
12 Income B4 Transfer/Cap Contribution	$ 14,133	$ 16,347	$ 16,118	$ 16,084	$ 13,905	$ 12,904	$ 16,612	$ 17,835	$ 18,776	$ 18,748	$ 21,188	$ 20,966	$ 22,989	$ 23,473	$ 23,139
13															
14 Net Transfers & Contributions In (Out)	(7,937)	(7,870)	(8,025)	(8,199)	(8,335)	(8,720)	(9,123)	(9,563)	(9,995)	(10,212)	(10,694)	(11,272)	(11,810)	(12,121)	(12,427)
15															
16 Change in Net Assets	$ 6,196	$ 8,476	$ 8,093	$ 7,885	$ 5,570	$ 4,184	$ 7,489	$ 8,272	$ 8,781	$ 8,536	$ 10,494	$ 9,695	$ 11,179	$ 11,352	$ 10,712
17															
18															
19															
20 01/01 Cash Balance	$ 14,217	$ 11,306	$ 13,944	$ 15,039	$ 16,965	$ 15,423	$ 11,998	$ 13,485	$ 14,725	$ 16,312	$ 16,847	$ 16,930	$ 49,733	$ 18,708	$ 20,737
21															
22 Change in Net Assets	6,196	8,476	8,093	7,885	5,570	4,184	7,489	8,272	8,781	8,536	10,494	9,695	11,179	11,352	10,712
23 Operating & Capital Activity	(22,624)	(4,288)	(5,385)	(14,987)	(19,873)	(5,261)	(3,534)	(4,433)	(4,460)	(5,124)	(7,381)	(39,664)	(38,009)	(5,946)	(5,777)
24 Bond Principle Payments	(1,484)	(1,550)	(1,612)	(1,973)	(2,239)	(2,349)	(2,468)	(2,599)	(2,734)	(2,877)	(3,030)	(3,969)	(4,194)	(3,378)	(3,580)
25 Bond Sale Proceeds	15,000	-	-	11,000	15,000	-	-	-	-	-	-	66,740	-	-	-
26															
27 Net Changes in Cash	$ (2,911)	$ 2,638	$ 1,095	$ 1,926	$ (1,542)	$ (3,426)	$ 1,487	$ 1,240	$ 1,587	$ 535	$ 84	$ 32,802	$ (31,024)	$ 2,028	$ 1,354
28															
29 12/31 Cash Balance	11,306	13,944	15,039	16,965	15,423	11,998	13,485	14,725	16,312	16,847	16,930	49,733	18,708	20,737	22,091
30 Reserve Minimum	11,221	10,530	10,826	11,823	12,287	12,036	12,245	12,979	13,926	14,935	15,819	17,405	17,890	16,631	17,469
31 Excess (Deficit) from Minimum	$ 85	$ 3,414	$ 4,214	$ 5,142	$ 3,136	$ (38)	$ 1,240	$ 1,746	$ 2,386	$ 1,912	$ 1,112	$ 32,328	$ 818	$ 4,105	$ 4,622
32															
33 Rate Change	21.0%	0.0%	0.0%	0.0%	0.0%	2.0%	1.0%	1.0%	1.0%	0.0%	2.0%	1.0%	2.0%	0.0%	0.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 3,802	$ 4,091	$ 4,710	$ 3,722	$ 4,480	$ 4,473	$ 4,000	$ 4,235	$ 4,327	$ 4,901	$ 6,424	$ 6,918	$ 5,460	$ 6,782	$ 6,670
37 Transmission Line Additions	-	-	-	11,000	11,000	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	-	-	-	-	-	-	33,370	33,370	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	10,000	-	-	-	4,000	-	-	-	-	-	-	-	-	-	-
41 Other	12,529	6,886	7,368	7,692	8,351	8,337	8,586	9,054	9,504	10,112	11,010	12,476	12,586	12,671	13,216
42 Total Capital Expenditures	$ 26,330	$ 10,977	$ 12,078	$ 22,414	$ 27,831	$ 12,810	$ 12,587	$ 13,289	$ 13,831	$ 15,013	$ 17,434	$ 52,764	$ 51,417	$ 19,453	$ 19,886
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ 15,000	$ -	$ -	$ 11,000	$ 15,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 66,740	$ -	$ -	$ -
47 Debt Service Payments	$ 4,636	$ 4,640	$ 4,636	$ 5,642	$ 6,789	$ 6,788	$ 6,788	$ 6,794	$ 6,796	$ 6,800	$ 6,801	$ 11,918	$ 11,924	$ 10,872	$ 10,872
48 Debt Outstanding	$ 58,566	$ 57,016	$ 55,404	$ 64,431	$ 77,193	$ 74,843	$ 72,376	$ 69,777	$ 67,043	$ 64,165	$ 61,135	$ 123,907	$ 119,712	$ 116,334	$ 112,754
49 Debt Service Coverage Ratio	5.0	5.7	5.7	4.9	4.0	3.8	4.4	4.6	4.8	4.9	5.3	3.4	4.0	4.2	4.2

Rochester Public Utilities
Financial Model Results
Scenario: Normal DSM, All Gas
Scenario Description: Recommenced plan adjuste
All dollar values in $1,000s

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 Sales of Electricity - Retail	$ 165,238	$ 172,422	$ 182,286	$ 192,532	$ 204,126	$ 213,105	$ 225,300	$ 238,194	$ 252,424	$ 266,240	$ 281,615	$ 294,741	$ 311,506	$ 329,224	$ 347,953
2 Other Revenues	23,229	24,032	24,836	25,640	26,437	27,295	28,246	29,249	30,306	31,357	32,457	33,611	34,861	36,115	37,447
3 Total Operating Revenues	$ 188,467	$ 196,453	$ 207,122	$ 218,173	$ 230,564	$ 240,400	$ 253,546	$ 267,443	$ 282,730	$ 297,597	$ 314,072	$ 328,353	$ 346,366	$ 365,340	$ 385,400
4															
5 Power Supply Costs	100,412	104,120	108,750	113,962	120,188	125,403	132,073	139,339	147,589	155,313	164,880	174,956	185,426	197,510	210,162
6 Net Other Operating Expenses	59,227	61,860	64,903	69,001	72,594	76,219	79,526	82,631	87,924	93,456	97,475	102,836	107,753	113,085	118,712
7 Total Operating Expenses	$ 159,639	$ 165,980	$ 173,653	$ 182,962	$ 192,783	$ 201,622	$ 211,599	$ 221,970	$ 235,513	$ 248,769	$ 262,355	$ 277,792	$ 293,179	$ 310,596	$ 328,874
8															
9 Operating Income	28,828	30,474	33,468	35,210	37,781	38,779	41,947	45,473	47,217	48,828	51,717	50,561	53,187	54,744	56,526
10 Interest Expense, Incl AFUDC	(6,942)	(6,665)	(6,409)	(8,033)	(7,187)	(7,194)	(6,826)	(10,507)	(9,025)	(9,296)	(8,836)	(8,437)	(8,175)	(7,767)	(7,343)
11 Interest and Other Income	675	663	651	868	915	781	843	1,272	1,294	939	960	979	1,050	1,115	1,107
12 Income B4 Transfer/Cap Contribution	$ 22,562	$ 24,471	$ 27,711	$ 28,045	$ 31,509	$ 32,366	$ 35,965	$ 36,238	$ 39,486	$ 40,472	$ 43,841	$ 43,102	$ 46,062	$ 48,093	$ 50,289
13															
14 Net Transfers & Contributions In (Out)	(12,779)	(13,403)	(14,107)	(14,832)	(15,657)	(16,430)	(17,292)	(18,200)	(19,202)	(20,160)	(21,229)	(22,335)	(23,498)	(24,722)	(26,010)
15															
16 Change in Net Assets	$ 9,783	$ 11,068	$ 13,604	$ 13,213	$ 15,852	$ 15,936	$ 18,673	$ 18,039	$ 20,284	$ 20,312	$ 22,612	$ 20,768	$ 22,564	$ 23,370	$ 24,279
17															
18															
19															
20 01/01 Cash Balance	$ 22,091	$ 22,266	$ 21,239	$ 21,543	$ 35,473	$ 24,643	$ 26,648	$ 28,738	$ 54,802	$ 30,139	$ 31,536	$ 31,515	$ 32,761	$ 36,184	$ 37,059
21															
22 Change in Net Assets	9,783	11,068	13,604	13,213	15,852	15,936	18,673	18,039	20,284	20,312	22,612	20,768	22,564	23,370	24,279
23 Operating & Capital Activity	(5,811)	(8,074)	(9,033)	(19,767)	(21,568)	(8,507)	(10,830)	(40,971)	(38,784)	(12,379)	(15,703)	(14,633)	(13,934)	(16,950)	(19,815)
24 Bond Principle Payments	(3,796)	(4,021)	(4,267)	(4,816)	(5,113)	(5,423)	(5,753)	(6,748)	(6,162)	(6,536)	(6,931)	(4,889)	(5,207)	(5,545)	(5,906)
25 Bond Sale Proceeds	-	-	-	25,300	-	-	-	55,744	-	-	-	-	-	-	-
26															
27 Net Changes in Cash	$ 175	$ (1,028)	$ 304	$ 13,930	$ (10,829)	$ 2,005	$ 2,090	$ 26,064	$ (24,663)	$ 1,397	$ (21)	$ 1,246	$ 3,423	$ 875	$ (1,442)
28															
29 12/31 Cash Balance	22,266	21,239	21,543	35,473	24,643	26,648	28,738	54,802	30,139	31,536	31,515	32,761	36,184	37,059	35,617
30 Reserve Minimum	18,556	19,299	20,003	22,026	23,209	23,741	25,051	27,286	28,938	29,002	29,447	30,679	32,802	34,781	35,825
31 Excess (Deficit) from Minimum	$ 3,711	$ 1,939	$ 1,539	$ 13,447	$ 1,434	$ 2,907	$ 3,687	$ 27,516	$ 1,201	$ 2,534	$ 2,068	$ 2,082	$ 3,382	$ 2,278	$ (209)
32															
33 Rate Change	0.0%	2.0%	3.0%	3.0%	3.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.0%	3.0%	3.0%	3.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 6,652	$ 8,248	$ 8,759	$ 7,321	$ 8,944	$ 9,005	$ 10,351	$ 10,797	$ 9,441	$ 11,215	$ 13,347	$ 12,774	$ 11,137	$ 13,509	$ 15,685
37 Transmission Line Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	12,650	12,650	-	-	27,872	27,872	-	-	-	-	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41 Other	13,817	14,906	15,722	16,343	17,544	18,032	19,237	20,931	21,465	22,234	23,851	24,761	25,428	27,283	29,145
42 Total Capital Expenditures	$ 20,468	$ 23,154	$ 24,482	$ 36,314	$ 39,138	$ 27,037	$ 29,588	$ 59,600	$ 58,779	$ 33,449	$ 37,198	$ 37,535	$ 36,565	$ 40,792	$ 44,831
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ -	$ -	$ -	$ 25,300	$ -	$ -	$ -	$ 55,744	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47 Debt Service Payments	$ 10,872	$ 10,869	$ 10,871	$ 12,807	$ 12,811	$ 12,811	$ 12,810	$ 17,079	$ 16,080	$ 16,079	$ 16,077	$ 13,614	$ 13,614	$ 13,614	$ 13,614
48 Debt Outstanding	$ 108,958	$ 104,937	$ 100,670	$ 121,154	$ 116,041	$ 110,617	$ 104,865	$ 153,861	$ 147,698	$ 141,163	$ 134,232	$ 129,343	$ 124,136	$ 118,591	$ 112,685
49 Debt Service Coverage Ratio	4.2	4.4	4.7	4.2	4.7	4.7	5.0	3.9	4.6	4.6	4.8	5.7	5.9	6.1	6.4

Rochester Public Utilities
Emission Rates and Externality Cost Rates
All Scenarios

	CT #1	CT #2	SLP	NewCoal	Proposed CT #3	Proposed CT #4	Proposed CT #6	SMMPA	Market
Emsn Rt-SO2-lbs/MWH-Coal/Gas Mix	n/a	n/a	4.84966	0.96000	n/a	n/a	n/a	0.48000	0.48000
Emsn Rt-PM10-lbs/MWH-Coal/Gas Mix	n/a	n/a	0.21384	0.17000	n/a	n/a	n/a	0.15500	0.15500
Emsn Rt-CO-lbs/MWH-Coal/Gas Mix	n/a	n/a	0.28432	1.44000	n/a	n/a	n/a	3.64500	3.64500
Emsn Rt-Nox-lbs/MWH-Coal/Gas Mix	n/a	n/a	1.59879	0.67000	n/a	n/a	n/a	0.77000	0.77000
Emsn Rt-Pb-lbs/MWH-Coal/Gas Mix	n/a	n/a	0.00061	0.00024	n/a	n/a	n/a	0.00012	0.00012
Emsn Rt-CO2-lbs/MWH-Coal/Gas Mix	n/a	n/a	2,460.96981	2,761.51000	n/a	n/a	n/a	1,943.49500	1,943.49500
Emsn Rt-SO2-lbs/MWH-All Gas	-	-	0.01000	0.96000	-	-	-	n/a	n/a
Emsn Rt-PM10-lbs/MWH-All Gas	0.01660	0.01660	0.07766	0.17000	0.01660	0.01660	0.14000	n/a	n/a
Emsn Rt-CO-lbs/MWH-All Gas	2.96000	2.96000	0.92400	1.44000	2.96000	2.96000	5.85000	n/a	n/a
Emsn Rt-Nox-lbs/MWH-All Gas	1.52000	1.52000	3.08000	0.67000	1.52000	1.52000	0.87000	n/a	n/a
Emsn Rt-Pb-lbs/MWH-All Gas	-	-	0.00001	0.00024	-	-	-	n/a	n/a
Emsn Rt-CO2-lbs/MWH-All Gas	1,051.20000	1,051.20000	1,126.00000	2,761.51000	1,051.20000	1,051.20000	1,125.48000	n/a	n/a
Extrnlty Rt-SO2-$/ton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extrnlty Rt-PM10-$/ton	$ 848.770	$ 848.770	$ 848.770	$ 848.770	$ 848.770	$ 848.770	$ 848.770	$ 848.770	$ 848.770
Extrnlty Rt-CO-$/ton	$ 0.371	$ 0.371	$ 0.371	$ 0.371	$ 0.371	$ 0.371	$ 0.371	$ 0.371	$ 0.371
Extrnlty Rt-Nox-$/ton	$ 72.036	$ 72.036	$ 72.036	$ 72.036	$ 72.036	$ 72.036	$ 72.036	$ 72.036	$ 72.036
Extrnlty Rt-Pb-$/ton	$ 508.950	$ 508.950	$ 508.950	$ 508.950	$ 508.950	$ 508.950	$ 508.950	$ 508.950	$ 508.950
Extrnlty Rt-CO2-$/ton	$ 2.036	$ 2.036	$ 2.036	$ 2.036	$ 2.036	$ 2.036	$ 2.036	$ 2.036	$ 2.036

Resource List

Unit	Unit Description	Scenario*	Peak Period MW Capacity	Years available From:	To:
CT #1	Combined Cycle Combustion Turbine, installed 1975	All scenarios	26	2005	2015
CT #2	Combined Cycle Combustion Turbine, installed 2002	All scenarios	47	2005	throughout
SLP	Silver Lake Plant	All scenarios	106	2005	2015
SLP		All scenarios	60	2016	throughout
NewCoal	Represents an ownership share in a baseload generating faciliy	1	50	2020	throughout
NewCoal		2	25	2025	throughout
NewCoal		4	25	2023	throughout
Proposed CT #3	FT8 TwinPac Combustion Turbine	1 and 4	50	2027	throughout
Proposed CT #3		2, 3, and 6	50	2029	throughout
Proposed CT #4	New Combined Cycle Combustion Turbine	6	25	2025	throughout
Proposed CT #6	LMS 100 High-Efficiency Combustion Turbine	1 and 4	100	2016	throughout
Proposed CT #6		2, 3, and 6	100	2018	throughout
SMMPA		All scenarios	216	2005	throughout

*See scenario descriptions below

Rochester Public Utilities
Emissions Cost and Tonnage for Retail Sales, 30 Yr Totals
Scenario #1: No DSM
Scenario Description: Recommended expansion plan from Part IV with the forecast unaffected by demand side management

	Resource	CT #1	CT #2	SLP	NewCoal	Proposed CT #3	Proposed CT #4	Proposed CT #6	SMMPA	Market	Grand Total
Retail MWH's		7,421	198,720	2,316,569	3,899,082	321,433	-	1,185,446	51,607,107	1,331,414	60,867,193
											-
Extrnlty Cost-SO2		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extrnlty Cost-PM10		$ 52	$ 1,400	$ 210,228	$ 281,301	$ 2,264	$ -	$ 70,432	$ 3,394,699	$ 87,580	$ 4,047,956
Extrnlty Cost-CO		$ 4	$ 109	$ 122	$ 1,040	$ 176	$ -	$ 1,285	$ 34,858	$ 899	$ 38,495
Extrnlty Cost-Nox		$ 406	$ 10,879	$ 133,400	$ 94,093	$ 17,598	$ -	$ 37,147	$ 1,431,264	$ 36,925	$ 1,761,713
Extrnlty Cost-Pb		$ -	$ -	$ 357	$ 239	$ -	$ -	$ -	$ 1,580	$ 41	$ 2,216
Extrnlty Cost-CO2		$ 7,941	$ 212,634	$ 5,803,055	$ 10,960,090	$ 343,938	$ -	$ 1,358,078	$ 102,093,492	$ 2,633,914	$ 123,413,142
Extrnlty Cost-Total		$ 8,403	$ 225,022	$ 6,147,162	$ 11,336,763	$ 363,977	$ -	$ 1,466,942	$ 106,955,893	$ 2,759,360	$ 129,263,522
Tons of Emissions-SO2		-	-	5,617.3	1,871.6	-	-	-	12,385.7	319.5	20,194.1
Tons of Emissions-PM10		0.1	1.6	247.7	331.4	2.7	-	83.0	3,999.6	103.2	4,769.2
Tons of Emissions-CO		11.0	294.1	329.3	2,807.3	475.7	-	3,467.4	94,054.0	2,426.5	103,865.4
Tons of Emissions-Nox		5.6	151.0	1,851.9	1,306.2	244.3	-	515.7	19,868.7	512.6	24,456.0
Tons of Emissions-Pb		-	-	0.7	0.5	-	-	-	3.1	0.1	4.4
Tons of Emissions-CO2		-	-	-	-	-	-	-	-	-	-

Rochester Public Utilities
Emissions Cost and Tonnage for Retail Sales, 30 Yr Totals
Scenario #2: Aggressive DSM, Coal & Gas Mix
Scenario Description: Recommended plan adjusted by using the aggressive demand side management results with SLP operating on coal and adjustments to the new resources

	Resource	CT #1	CT #2	SLP	NewCoal	Proposed CT #3	Proposed CT #4	Proposed CT #6	SMMPA	Market	Grand Total
Retail MWH's		175	140,248	1,651,836	1,422,649	218,631	-	981,553	49,263,686	1,011,076	54,689,854
											-
Extrnlty Cost-SO2		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extrnlty Cost-PM10		$ 1	$ 988	$ 149,904	$ 102,638	$ 1,540	$ -	$ 58,318	$ 3,240,549	$ 66,508	$ 3,620,446
Extrnlty Cost-CO		$ 0	$ 77	$ 87	$ 380	$ 120	$ -	$ 1,064	$ 33,275	$ 683	$ 35,686
Extrnlty Cost-Nox		$ 10	$ 7,678	$ 95,121	$ 34,331	$ 11,969	$ -	$ 30,758	$ 1,366,272	$ 28,041	$ 1,574,181
Extrnlty Cost-Pb		$ -	$ -	$ 255	$ 87	$ -	$ -	$ -	$ 1,508	$ 31	$ 1,881
Extrnlty Cost-CO2		$ 187	$ 150,068	$ 4,137,884	$ 3,998,981	$ 233,939	$ -	$ 1,124,493	$ 97,457,540	$ 2,000,196	$ 109,103,288
Extrnlty Cost-Total		$ 198	$ 158,811	$ 4,383,251	$ 4,136,417	$ 247,568	$ -	$ 1,214,632	$ 102,099,145	$ 2,095,459	$ 114,335,481
Tons of Emissions-SO2		-	-	4,005.4	682.9	-	-	-	11,823.3	242.7	16,754.2
Tons of Emissions-PM10		0.0	1.2	176.6	120.9	1.8	-	68.7	3,817.9	78.4	4,265.5
Tons of Emissions-CO		0.3	207.6	234.8	1,024.3	323.6	-	2,871.0	89,783.1	1,842.7	96,287.3
Tons of Emissions-Nox		0.1	106.6	1,320.5	476.6	166.2	-	427.0	18,966.5	389.3	21,852.7
Tons of Emissions-Pb		-	-	0.5	0.2	-	-	-	3.0	0.1	3.7
Tons of Emissions-CO2		-	-	-	-	-	-	-	-	-	-

Rochester Public Utilities
Emissions Cost and Tonnage for Retail Sales, 30 Yr Totals
Scenario #3: Aggressive DSM, All Gas
Scenario Description: Recommended plan adjusted by using the aggressive demand side management results with SLP operating on natural gas and the coal unit replaced with gas-fired capacity

Resource	CT #1	CT #2	SLP	NewCoal	Proposed CT #3	Proposed CT #4	Proposed CT #6	SMMPA	Market	Grand Total
Retail MWH's	175	140,248	2,101,143	-	265,579	200,745	1,110,130	49,263,686	1,387,061	54,468,767
										-
Extrnlty Cost-SO2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extrnlty Cost-PM10	$ 1	$ 988	$ 69,249	$ -	$ 1,871	$ 1,414	$ 65,957	$ 3,240,549	$ 91,240	$ 3,471,270
Extrnlty Cost-CO	$ 0	$ 77	$ 360	$ -	$ 146	$ 110	$ 1,203	$ 33,275	$ 937	$ 36,108
Extrnlty Cost-Nox	$ 10	$ 7,678	$ 233,091	$ -	$ 14,540	$ 10,990	$ 34,787	$ 1,366,272	$ 38,469	$ 1,705,836
Extrnlty Cost-Pb	$ -	$ -	$ 3	$ -	$ -	$ -	$ -	$ 1,508	$ 42	$ 1,553
Extrnlty Cost-CO2	$ 187	$ 150,068	$ 2,408,236	$ -	$ 284,174	$ 214,800	$ 1,271,794	$ 97,457,540	$ 2,744,000	$ 104,530,799
Extrnlty Cost-Total	$ 198	$ 158,811	$ 2,710,939	$ -	$ 300,731	$ 227,315	$ 1,373,741	$ 102,099,145	$ 2,874,688	$ 109,745,567
Tons of Emissions-SO2	-	-	10.5	-	-	-	-	11,823.3	332.9	12,166.7
Tons of Emissions-PM10	0.0	1.2	81.6	-	2.2	1.7	77.7	3,817.9	107.5	4,089.8
Tons of Emissions-CO	0.3	207.6	970.7	-	393.1	297.1	3,247.1	89,783.1	2,527.9	97,426.8
Tons of Emissions-Nox	0.1	106.6	3,235.8	-	201.8	152.6	482.9	18,966.5	534.0	23,680.3
Tons of Emissions-Pb	-	-	0.0	-	-	-	-	3.0	0.1	3.1
Tons of Emissions-CO2	-	-	-	-	-	-	-	-	-	-

Rochester Public Utilities
Emissions Cost and Tonnage for Retail Sales, 30 Yr Totals
Scenario #4: Normal DSM, Coal & Gas Mix
Scenario Description: Recommended plan adjusted by using the normal demand side management forecast with SLP operating on coal and adjustments to the new resources.

Resource	CT #1	CT #2	SLP	NewCoal	Proposed CT #3	Proposed CT #4	Proposed CT #6	SMMPA	Market	Grand Total
Retail MWH's	531	112,756	1,718,855	1,663,208	285,682	-	1,035,546	49,706,665	1,090,275	55,613,517
										-
Extrnlty Cost-SO2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extrnlty Cost-PM10	$ 4	$ 794	$ 155,985	$ 119,993	$ 2,013	$ -	$ 61,526	$ 3,269,688	$ 71,718	$ 3,681,721
Extrnlty Cost-CO	$ 0	$ 62	$ 91	$ 444	$ 157	$ -	$ 1,123	$ 33,575	$ 736	$ 36,187
Extrnlty Cost-Nox	$ 29	$ 6,173	$ 98,981	$ 40,137	$ 15,640	$ -	$ 32,450	$ 1,378,558	$ 30,238	$ 1,602,204
Extrnlty Cost-Pb	$ -	$ -	$ 265	$ 102	$ -	$ -	$ -	$ 1,521	$ 33	$ 1,922
Extrnlty Cost-CO2	$ 568	$ 120,650	$ 4,305,767	$ 4,675,180	$ 305,684	$ -	$ 1,186,349	$ 98,333,879	$ 2,156,872	$ 111,084,950
Extrnlty Cost-Total	$ 601	$ 127,680	$ 4,561,089	$ 4,835,856	$ 323,494	$ -	$ 1,281,446	$ 103,017,221	$ 2,259,598	$ 116,406,984
Tons of Emissions-SO2	-	-	4,167.9	798.3	-	-	-	11,929.6	261.7	17,157.5
Tons of Emissions-PM10	0.0	0.9	183.8	141.4	2.4	-	72.5	3,852.3	84.5	4,337.7
Tons of Emissions-CO	0.8	166.9	244.4	1,197.5	422.8	-	3,029.0	90,590.4	1,987.0	97,638.7
Tons of Emissions-Nox	0.4	85.7	1,374.0	557.2	217.1	-	450.5	19,137.1	419.8	22,241.7
Tons of Emissions-Pb	-	-	0.5	0.2	-	-	-	3.0	0.1	3.8
Tons of Emissions-CO2	-	-	-	-	-	-	-	-	-	-

Rochester Public Utilities
Emissions Cost and Tonnage for Retail Sales, 30 Yr Totals
Scenario #5: Normal DSM, All Gas
Scenario Description: Recommenced plan adjusted by using the normal demand side management forecast with SLP operating on natural gas and the coal unit replaced with gas-fired capacity

Resource	CT #1	CT #2	SLP	NewCoal	Proposed CT #3	Proposed CT #4	Proposed CT #6	SMMPA	Market	Grand Total
Retail MWH's	531	167,555	2,250,599	-	283,254	215,265	1,203,823	49,706,665	1,532,831	55,360,523
										-
Extrnlty Cost-SO2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extrnlty Cost-PM10	$ 4	$ 1,180	$ 74,175	$ -	$ 1,995	$ 1,516	$ 71,524	$ 3,269,688	$ 100,829	$ 3,520,912
Extrnlty Cost-CO	$ 0	$ 92	$ 385	$ -	$ 155	$ 118	$ 1,305	$ 33,575	$ 1,035	$ 36,666
Extrnlty Cost-Nox	$ 29	$ 9,173	$ 249,671	$ -	$ 15,507	$ 11,785	$ 37,723	$ 1,378,558	$ 42,511	$ 1,744,958
Extrnlty Cost-Pb	$ -	$ -	$ 3	$ -	$ -	$ -	$ -	$ 1,521	$ 47	$ 1,571
Extrnlty Cost-CO2	$ 568	$ 179,286	$ 2,579,536	$ -	$ 303,086	$ 230,338	$ 1,379,131	$ 98,333,879	$ 3,032,374	$ 106,038,198
Extrnlty Cost-Total	$ 601	$ 189,732	$ 2,903,770	$ -	$ 320,744	$ 243,757	$ 1,489,683	$ 103,017,221	$ 3,176,797	$ 111,342,305
Tons of Emissions-SO2	-	-	11.3	-	-	-	-	11,929.6	367.9	12,308.7
Tons of Emissions-PM10	0.0	1.4	87.4	-	2.4	1.8	84.3	3,852.3	118.8	4,148.3
Tons of Emissions-CO	0.8	248.0	1,039.8	-	419.2	318.6	3,521.2	90,590.4	2,793.6	98,931.5
Tons of Emissions-Nox	0.4	127.3	3,465.9	-	215.3	163.6	523.7	19,137.1	590.1	24,223.4
Tons of Emissions-Pb	-	-	0.0	-	-	-	-	3.0	0.1	3.1
Tons of Emissions-CO2	-	-	-	-	-	-	-	-	-	-

Attachment B

Recommendation – CapX 2020 Certificate of Need

PUC Docket E002/CN-06-1115
OAH Docket 15-2500-193500-2

PUC Docket No. E002/CN-06-1115
OAH 15-2500-19350-2

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Great River Energy, Northern States Power Company (d/b/a Xcel Energy) and others for Certificates of Need for Three 345 kV Transmission Lines

TABLE OF CONTENTS

Page

OAH 15-2500-19350-2
PUC ET-2,E-002, et al./CN-06-1115

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Great River Energy, Northern States Power Company (d/b/a Xcel Energy) and others for Certificates of Need for Three 345 kV Transmission Lines

FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATIONS

A public hearing was held before Beverly Jones Heydinger, Administrative Law Judge (ALJ), commencing on June 17, 2008, at Moorhead, Minnesota, and continuing at dates and places more specifically set forth below. The evidentiary portion of the hearing was held from July 14, 2008, to August 1, 2008; from August 11, 2008, to August 14, 2008; and from September 11, 2008, to September 18, 2008, in Saint Paul, Minnesota.

The hearing record closed upon receipt of the Post-Hearing Reply Memoranda on January 23, 2009.

Appearances:

Michael C. Krikava and Lisa M. Agrimonti, Briggs and Morgan, P.A., and Priti Patel, Assistant General Counsel, Northern States Power Company (Xcel Energy), on behalf of Xcel Energy and co-Applicant Great River Energy (GRE), (Applicants), and other CapX2020 utilities.

Joyce Osborn and Roger Tupy, on behalf of United Citizens Action Network (UCAN).

Paula Maccabee, Attorney at Law, on behalf of Citizens Energy Task Force (CETF).

Carol Overland, Overland Law Office, on behalf of NoCapX2020 (NoCapX).[1]

[1] At the time Ms. Overland filed a Notice of Appearance, she was suspended from the practice of law and NoCapX was not registered as an organization with the Secretary of State. Thus, Ms. Overland appeared

George Crocker, Executive Director, North American Water Office, on behalf of the North American Water Office and the Institute for Local Self Reliance (NAWO/ILSR).

Mary Winston Marrow and Elizabeth Goodpaster, Staff Attorneys, Minnesota Center for Environmental Advocacy (MCEA), on behalf of MCEA, Wind on the Wires, Izaak Walton League of America - Midwest Office, and Fresh Energy (collectively, MCEA or Joint Intervenors).

Christopher K. Sandberg, Lockridge Grindal Nauen, on behalf of Midwest Independent Transmission System Operator, Inc. (MISO).

Julia Anderson, Assistant Attorney General, on behalf of the Department of Commerce, Office of Energy Security (OES).

Bob Cupit and Bret Eknes, planning directors, Minnesota Public Utilities Commission (Commission), appeared on behalf of the Commission.[2]

STATEMENT OF THE ISSUES

Have Applicants satisfied the criteria set forth in Minnesota Statutes § 216B.243, Minnesota Rules Chapter 7849[3] and other applicable statutes, for Certificates of Need for three 345 kV transmission line projects, collectively referred to as CapX2020 (CapX):

a. Twin Cities to La Crosse 345 kV project (La Crosse Project);

b. Twin Cities to Fargo 345 kV project (Fargo Project);

c. Twin Cities to Brookings 345 kV project (Brookings Project).

SUMMARY OF RECOMMENDATIONS

1. That the Commission approve the La Crosse Project as proposed, subject to the following:

a. The final decision concerning the location of the Mississippi River crossing and the termination point near La Crosse shall be made in the routing proceeding;

b. Approve the third quarter of 2011 as the in-service date for the Northern Hills-North Rochester 161 kV line, subject to modification in the course of proceedings addressing the certificates of need for the RIGO projects.

---

on her own behalf until August 11, 2008, when the organization registered, and as Executive Director from that date until she was reinstated on September 3, 2008.

[2] Commission staff Tricia DeBleeckere and Andrew Mensing assisted at the public hearings; Mr. Mensing also assisted at the evidentiary hearing.

[3] Unless otherwise noted, statutes are cited to the 2008 edition and rules are cited to the 2007 edition.

c. Approve the North Rochester-Chester 161 kV line, or in the alternative, a direct connection of the 345 kV line at the Chester Substation, if dictated by selection of the Southern Crossing in the routing proceeding.

2. That the Commission approve the Fargo Upsized Alternative, subject to the following: The decision whether the northwestern termination should be at the Maple River Substation or at a new substation near Fargo, North Dakota, shall be determined in the routing proceeding, with due regard for the authority of the North Dakota Public Service Commission.

3. That the Commission approve the Brookings Upsized Alternative, subject to the following: The decision whether the eastern termination should be at the Lake Marion Substation or the Hampton Corners Substation cannot be made on this record. The Commission may request that the Applicants explain why the new substation was included in the supporting studies, and its benefits to regional reliability, community load serving, and generation outlet.

Based on the evidence in the hearing record, the Administrative Law Judge makes the following:

FINDINGS OF FACT

Applicants

1. Xcel Energy is a public utility. Xcel Energy owns and operates high voltage transmission lines in Minnesota and delivers electricity to its customers in Minnesota, North Dakota, and South Dakota.

2. GRE is a generation and transmission cooperative that operates high voltage transmission lines in Minnesota and provides wholesale electric service to 28 distribution cooperatives. GRE is not a public utility.

3. Xcel Energy and GRE, the Applicants, have jointly applied as the Applicants for Certificates of Need to construct three 345 kV transmission line projects from the Twin Cities metropolitan area to La Crosse, Fargo, and Brookings. Each project includes a 345kV transmission line and associated system upgrades. GRE is participating in the planning and development of the Brookings Project and Fargo Project; Xcel Energy is participating in the planning and development of all three proposed projects.

4. Each of the three projects meets the definition of “large energy facility” and requires a certificate of need.[4]

[4] Minn. Stat. §§ 216B.243 and 216B.2421; Transcript volume (T.) 15 at 123 (Alders).

5. The Applicants are acting on their own behalf and also on behalf of other utilities participating in the proposed CapX expansion. Other utilities participating in the development of the three projects are:

- Central Minnesota Municipal Power Agency (Brookings Project)
- Dairyland Power Cooperative (La Crosse Project)
- Minnesota Power (Fargo Project)
- Missouri River Energy Services (Fargo Project and Brookings Project)
- Otter Tail Power Company (Fargo Project and Brookings Project)
- Rochester Public Utilities (La Crosse Project)
- Southern Minnesota Municipal Power Agency (La Crosse Project)
- Wisconsin Public Power, Inc. (La Crosse Project)

6. The utilities have signed a Participation Agreement to jointly plan, coordinate and identify transmission upgrades and additions for the region. A copy of the Participation Agreement is attached to the Application.[5] In addition, participating utilities have signed Project Development Agreements (PDAs) setting out their participation with the three CapX projects.[6] Each of the three projects has a "Development Manager" responsible for obtaining major permits and overseeing the project if it is authorized. GRE is the Development Manager for the Brookings Project; Xcel Energy is the Development Manager for the Fargo and La Crosse Projects.[7]

7. The PDAs do not require the participating utilities to own the completed transmission lines, but each signatory will have the right to invest in the ownership. Figure 1-11 of the Application sets forth the potential/non-binding ownership percentages.[8]

8. Since the Participation Agreement and the PDAs were signed, no additional participants have joined or withdrawn from CapX, and there have been no other amendments to either the Participation Agreement or the PDAs.[9]

9. Although the participating utilities are engaged in the development of one or more of the three transmission line projects, Xcel Energy and GRE are the Applicants

[5] Ex. 2, Appendix (Apx.) B-1.
[6] Ex. 1 at 1.24-1.25 (Application); Ex. 64 at 12-13 (McCarten Direct); Ex. 2, Apx. B-2, B-3 and B-4.
[7] Ex. 64 at 13-14 (McCarten Direct).
[8] Reproduced at Ex. 64 at 16 (McCarten Direct).
[9] T. 6 at 70-73 (McCarten).

and have assumed the responsibility to implement the Commission's orders in this proceeding.[10]

10. The Applicants have presented an alternative for each of the three proposed projects. In each instance, their alternative, the "Upsized Alternative," would increase the future capacity of the proposed project.

Other Parties

11. UCAN is a group of Minnesota landowners whose private property interests may be directly affected by the outcome of the certificate of need application. It advocates for the rights of landowners and citizens in state regulatory proceedings concerning construction of large energy facilities.[11] UCAN asserts that the Applicants have failed to show that the proposed projects are needed to serve local load, to assure regional reliability, or to assure compliance with the State's renewable energy standards.

12. CETF is a public interest group of Dakota County residents, many of whom are concerned that the proposed CapX projects would directly impact their property.[12] CETF asserts that the certificate of need for the La Crosse Project should not be granted; that the certificate of need for the Fargo Project should not be granted, except for the segment from Monticello to St. Cloud; and that the certificate of need for the Brookings Project as proposed should be granted, subject to conditions that support renewable wind energy, enhance community-based energy development, and minimize the adverse effect on residents and farm workers.

13. NoCapX is an organization of landowners and residents in the vicinity of one of the transmission corridors.[13] NoCapX asserts that the Applicants have not met their burden of proving that the CapX projects meet the criteria for a certificate of need and that the size of the proposed projects far exceeds the demonstrated need to serve projected load growth.

14. NAWO/ILSR represents the interests of community-based renewable energy projects that may be affected by the development of the electrical transmission grid.[14] NAWO/ILSR asserts that the certificate of need for the La Crosse Project should be denied, and that the certificate of need for the Fargo Project should be denied, except for the segment from Monticello to St. Cloud. It also opposes the certificate of need for the Brookings Project, but if the certificate of need is granted, NAWO/ILSR requests that it be conditioned upon the Applicants entering into power purchase

---

[10] T. 15 at 124-125 (Alders); Ex. 64 at 13-14 (McCarten Direct).
[11] Petition to Intervene of United Citizens Action Network.
[12] Petition to Intervene of Citizens Energy Task Force.
[13] NoCapX2020 Petition to Intervene.
[14] Petition to Intervene of the North American Water Office (NAWO) and the Institute for Local Self Reliance (ILSR).

agreements for 600 megawatts (MW) of renewable energy from 10 MW to 40 MW community-based energy development (C-BED) projects.[15]

15. MCEA (or Joint Intervenors) represents four organizations that actively support wind energy development. Wind on the Wires is a policy organization focused on overcoming the barriers to delivering wind energy to market in the Upper Midwest. Wind on the Wires has many member organizations, including environmental organizations, wind developers, tribal interests, and businesses that supply goods and services to the wind industry. The Izaak Walton League of America – Midwest Office is a nonprofit conservation organization committed to protecting fish and wildlife, critical habitat, and air and water resources. Fresh Energy is a nonprofit organization that works in the public interest to stimulate technological advancements for sustainable energy. MCEA is a nonprofit environmental organization with five programs, including an energy program, which advances the pursuit of environmentally sustainable sources of energy.[16] MCEA supports granting the certificates of need for the projects as proposed or the Upsized Alternatives if conditions are placed on the certificates requiring that any additional firm generation outlet capacity created by the CapX projects be used to fulfill the Applicants' requirements under the State's renewable energy standards. MCEA prefers the Upsized Alternative.

16. MISO is the independent regional transmission operator for 15 states and the province of Manitoba.[17] It administers a common tariff that applies to transmission services in the region and operates a wholesale energy market that prices transmission services and balances generation supply and transmission. MISO conducts long-term studies to assure sufficient transmission to serve load, meet renewable energy mandates, and serve existing and new generation.[18] It periodically issues Midwest ISO Transmission Expansion Plans (MTEP).[19] MISO oversees a process for new interconnection requests to be studied and added to the transmission system, the "MISO queue" process. MISO asserts that the Applicants have met their burden of proving that all three CapX projects meet the criteria for certificates of need as proposed by the Applicants.

17. OES was created by Executive Order to address the statutory duties of the commissioner of commerce for energy, climate change, and greenhouse emissions. By statute, it has the right to intervene in certificate of need proceedings.[20] Its Energy Issues Intervention Office represents the interests of Minnesota in energy matters outside the state as well.[21] OES recommends that the certificates of need be granted

[15] NAWO/ILSR asserts that the need to serve local load in Saint Cloud could be addressed by a short extension of a 345 kV line from Monticello or unspecified "competitive generation."
[16] Petition to Intervene of Wind on the Wires, Izaak Walton League of America – Midwest Office, Fresh Energy and Minnesota Center for Environmental Advocacy.
[17] Ex. 61 is a list of the MISO members.
[18] Petition to Intervene of the Midwest ISO.
[19] *See, e.g.,* Ex. 59, MTEP 07.
[20] Executive Order, January 17, 2008; Minn. Stat. § 216C.10 (a)(9).
[21] Minn. Stat. § 216A.085.

for the Upsized Alternative, with some modifications to the Applicants' proposed endpoints for the La Crosse Project and the Fargo Project.

18. The Prairie Island Indian Community was granted party status on January 3, 2008.[22] It asked to withdraw as a party on August 15, 2008, and was dismissed without objection on August 21, 2008.

Brief Description of the Proposed Projects

19. The Applicants have applied for certificates of need to construct three 345 kV transmission line projects to improve regional transmission system reliability, enhance community service, and increase generation outlet capacity, particularly for renewable energy. Each of the three projects is functionally independent and does not depend on another project to go forward.[23]

20. The La Crosse Project includes an approximately 150-mile long 345kV transmission line from a proposed new Hampton Corner substation in the southeast quadrant of the Twin Cities area to a new substation that would be built in the La Crosse, Wisconsin area. This project also includes two 161 kV transmission lines.[24]

21. The Applicants initially proposed four alternative points for the La Crosse Project to cross the Mississippi River from Minnesota to Wisconsin. The Trempealeau crossing was withdrawn from consideration,[25] but the others, at Alma (Alma Crossing), or at Winona/La Crescent (Southern Crossing), are still proposed alternatives.

22. The Fargo Project includes an approximately 250-mile 345 kV line from Fargo, North Dakota, to Alexandria, St. Cloud, and Monticello.[26]

23. The Brookings Project includes an approximately 200-mile 345 kV line from Brookings, South Dakota, to the southeastern quadrant of the Twin Cities area, with a related 345 kV transmission line between Marshall and the east side of Granite Falls.[27]

24. The estimated cost of the three projects as proposed, including upgrades to the underlying system, is $1.42 to $1.7 billion.[28]

25. In prefiled testimony, OES witness Dr. Rakow recommended that the Fargo Project be "upsized" to single circuit 500 kV rather than single circuit 345 kV

[22] First Prehearing Order, Jan. 3, 2008.
[23] T. 15 at 123-124 (Alders).
[24] Ex. 1 at 2.1 (Application); Ex. 83 at 3 (Stevenson Direct).
[25] Ex. 128 at 9-10 (Rasmussen Direct).
[26] Ex. 1 at 2.1 (Application); Ex. 83 at 11 (Stevenson Direct).
[27] Ex. 1 at 2.1 (Application); Ex. 116 at 2 (Lennon Direct).
[28] The costs are summarized on Attachment F to this Report.

proposed by the Applicants.[29] MCEA witness Mr. Schedin recommended that the project be built as double-circuit 345 kV rather than single circuit 345 kV.[30]

26. In response to this testimony, the Applicants re-examined all three of the projects and concluded that their initial proposals were sufficient to meet the regional reliability, load-serving, and immediate generation outlet needs, but that there could be benefits to building larger facilities to provide greater future capacity. The Applicants proposed an alternative in their Rebuttal Testimony, referred to as the "Double-Circuit Compatible Alternative" or "Upsized Alternative."[31]

27. In general, the Upsized Alternative increases the size of the structures that carry the transmission lines so that the structures are large enough to accommodate a second 345 kV circuit line at a later date. One side of the poles would be strung upon construction, and the davit arms for the second side and the second circuit would be added at a later date as needed.[32] Applicants' acknowledge that the second circuit could not be strung without obtaining a certificate of need or other regulatory approvals in a subsequent proceeding.[33]

28. The estimated cost of the Upsized Alternative, including upgrades to the underlying system, is approximately $1.6 billion to $1.9 billion, an increase of about $200 million above the CapX projects as proposed.[34]

29. The configurations included in the Application and in the Upsized Alternative are depicted in Exhibit 22 (Fargo Project), Exhibit 23 (Brookings Project), Exhibit 24 (La Crosse Project, Southern Crossing), and Exhibit 25 (La Crosse Project, Alma Crossing), which are Attachments A-D to this Report. The estimated costs for each project are summarized on Attachment F to this Report.

Procedural Summary

30. Initially, GRE and Xcel Energy filed separate applications for certificates of need for the three projects, but in an order dated November 3, 2006, the Commission authorized the Applicants to address all three projects in a single application for certificates of need to be filed in Docket No. ET-2/CN-06-1115.

31. On February 5, 2007, Applicants submitted a Request for Exemption from Certain Certificate of Need Application Content Requirements. Applicants also requested leave to proceed on behalf of themselves and the other CapX2020 utilities, although the ultimate ownership of the proposed transmission facilities would be deferred to a later date.

---

[29] Ex. 282 at 20-21, 72-78 (Rakow Direct).
[30] Ex. 177 at 23 (Schedin Direct).
[31] Ex. 121 at 9 (Grivna Rebuttal).
[32] Ex. 121 at 10 (Grivna Rebuttal).
[33] Ex. 121 at 32, 36-37 (Grivna Rebuttal).
[34] *See* Attachment F to this Report.

32. On June 4, 2007, the Commission issued its *Order Designating Applicants and Setting Filing Requirements* that modified Applicants' filing requirements, waived certain rules, and specified information to be included in the complete application.

33. On August 16, 2007, Applicants filed an Application for Certificate of Need for Three 345 kV Transmission Line Projects with Associated System Connections (Application) on behalf of themselves and the other CapX utilities.

34. On November 21, 2007, the Commission accepted the Application as substantially complete pending a supplemental filing, and assigned the Administrative Law Judge to conduct the contested case hearing.[35]

35. A prehearing conference was held on December 18, 2007, and on January 3, 2008, the First Prehearing Order was issued, setting the schedule and parameters for the contested case, including a number of prehearing deadlines. At the prehearing conference, the parties concurred with the proposed schedule and Applicants agreed, in light of the size of the proposed projects, that there was good cause to extend the timeline for the Commission's action on the Application beyond November 27, 2008, as permitted pursuant to Minn. Stat. § 216B.243, subd. 5. Amended scheduling orders were issued on April 22, 2008, May 5, 2008, and May 22, 2008.

36. Applicants filed Direct Testimony on May 15, 2008.

37. OES, MISO, MCEA, NAWO/ILSR and CETF filed Direct Testimony on May 23, 2008. On June 16, 2008, Applicants, OES, MCEA and NAWO/ILSR filed Rebuttal Testimony. On July 3, 2008, Applicants, OES, MCEA and NAWO/ILSR filed Surrebuttal Testimony. Neither UCAN nor NoCapX prefiled any testimony.

38. From June 17, 2008, to July 2, 2008, 19 public hearings were held in 13 different Minnesota communities in the corridors where the three projects are proposed to be located. Public hearings were held in: Moorhead, Fergus Falls, Alexandria, Melrose, Clearwater, Marshall, Redwood Falls, Arlington, New Prague, Lakeville, Cannon Falls, Winona, and Rochester.[36]

39. The evidentiary hearing commenced in Saint Paul on July 14, 2008, at the Commission's hearing rooms. There were 25 days of hearing, concluding on September 18, 2008. There were more than 300 exhibits received into evidence and 25 witnesses called for cross-examination. Also, on September 18, 2008, Final Rebuttal

[35] *Order Accepting Application as Substantially Complete Pending Supplemental Filing,* November 21, 2007.

[36] A petition to add a hearing in La Crescent or La Crosse dated Aug. 8, 2008, was filed as a public comment, after the start of the evidentiary hearing. Chipps, filed 8/08/08, Department of Commerce e-docket document number (#) 5464471. *See* Minn. R. 7829.1100, stating a preference that public hearings be held prior to the start of the evidentiary hearing.

Testimony, making minor cost corrections, was filed by the Applicants without objection,[37] and the post-hearing briefing schedule was set.

40. Notice of the public hearings and the evidentiary hearing was published in newspapers throughout the state, as set forth in the Affidavit of Publication, Minnesota Newspaper Association.[38] Supplemental notice of the hearings and additional information was sent to approximately 80,000 customers.[39]

41. Transcripts were prepared for each of the public hearings and the evidentiary hearing and were placed in 37 public libraries for access by the public. [40]

42. On September 26, 2008, the period for public comments closed. Comments were received at the public hearings, by U.S. mail, and by electronic mail. All of the comments have been included in the record and are summarized below.

43. On October 21, 2008, the Applicants concurred in the briefing schedule and agreed that the deadline for action by the Commission on the certificate of need, November 27, 2008, could be extended to allow sufficient time for the briefing, report of the ALJ and the deliberations of the Commission.[41]

Environmental Report

44. Minnesota Rule 7849.7030 requires the Department of Commerce to prepare an environmental report (ER) on a proposed high voltage transmission line as part of the certificate of need process:

> The environmental report must contain information on the human and environmental impacts of the proposed project associated with the size, type, and timing of the project, system configurations, and voltage. The environmental report must also contain information on alternatives to the proposed project and shall address mitigating measures for anticipated adverse impacts. The commissioner [of commerce] shall be responsible for the completeness and accuracy of all information in the environmental report.

45. Minnesota Rule 7849.7060, subps. 1 and 3, sets forth the topics the ER must address for proposed high voltage transmission lines.

46. On February 18, 2008, the Commissioner of Commerce issued the "Environmental Report Scoping Decision," clarifying that the ER "provides a high level environmental analysis of the proposal and system alternatives, and reviews environmental impacts associated with named and alternative project corridors," that the

[37] Ex. 312.
[38] Ex. 314.
[39] Ex. 31 (Carlsgaard Direct); Ex. 43 (Carlsgaard Rebuttal); Exs. 33-42, 44-47.
[40] Exs. 315; 316; *Final Notice of Availability of Evidentiary Hearing Transcripts*, Filed 10/3/08, #5547758.
[41] Letter from Michael C. Krikava, Counsel for Applicants, October 21, 2008; Minn. Stat. § 216B.243, subd. 5.

ER was only one part of the Department's investigation of the certificate of need application, and that the ER was not intended to evaluate specific route alternatives. It also spelled out the matters to be addressed in the ER.[42]

47. OES completed the ER on March 31, 2008. It addressed each topic required by Minn. R. 7849.7060, subps. 1, 3 and 7.[43] Because the ER is prepared at an early point in the certificate of need process, prior to the filing of testimony, it is necessarily a preliminary review.[44]

Criteria for Certificate of Need

48. Minnesota Statute § 216B.243 requires a certificate of need prior to construction of a "large energy facility." A large energy facility includes "any high-voltage transmission line with a capacity of 100 kilovolts or more with more than ten miles of its length in Minnesota or that crosses a state line."[45]

49. Each of the three transmission lines and associated facilities, the La Crosse, Fargo and Brookings Projects, constitutes a large energy facility and requires a certificate of need from the Commission before construction can take place.

50. In assessing the need for a proposed transmission line, the criteria set forth in Minn. Stat. § 216B.243, subd. 3, and Minn. R. 7849.0120 must be evaluated. The Applicants bear the burden of proving the need for the proposed transmission line and that the "demand for electricity cannot be met more cost effectively through energy conservation and load-management."[46]

51. Section 216B.243, subd. 3a, must also be evaluated. It states:

> The commission may not issue a Certificate of Need under this section for a large energy facility that … transmits electric power generated by means of a nonrenewable energy source, unless the applicant for the certificate has demonstrated to the commission's satisfaction that it has explored the possibility of generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source. For purposes of this subdivision, "renewable energy source" includes hydro, wind, solar, and geothermal energy and the use of trees or other vegetation as fuel.

52. Pursuant to Minn. Stat. § 216B.2422, subd. 4, the Commission shall not grant a certificate of need pursuant to section 216B.243 nor allow rate recovery for a

---

[42] Ex. 162, *Environmental Report Scoping Decision,* Minnesota Department of Commerce, PUC Docket No. ET02, E002/CN-06-1115, Feb. 18, 2008.
[43] Ex. 5.
[44] T. 17A at 55-56 (Birkholz).
[45] Minn. Stat. § 216B.2421, subd. 2 (3).
[46] Minn. Stat. § 216B.243, subd. 3.

nonrenewable energy facility "unless the utility has demonstrated that a renewable energy facility is not in the public interest."

53. Under section 216B.243, subd. 3(10), as a condition of granting the certificate of need, the Applicants must comply with the renewable energy goals (referred to as the Renewable Energy Standards or RES) enacted in 2007:

> [E]ach electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota are generated by eligible energy technologies by the end of the year indicated: 1) 2012 – 12 percent; 2) 2016 – 17 percent; 3) 2020 – 20 percent; and 4) 2025 – 25 percent.[47]

54. Xcel Energy, one of the Applicants, and the largest projected owner of the CapX projects, has higher RES requirements: 1) 2010 – 15 percent; 2) 2012 – 18 percent; 3) 2016 – 25 percent; and 4) 2020 – 30 percent.[48]

55. In evaluating compliance with the RES, the Commission must also consider whether the proposed project will provide opportunities to interconnect "distributed generation," high-efficiency, low-emissions generation of no more than 10 MW of interconnected capacity,[49] as well as the utility's efforts to purchase C-BED projects.[50]

56. If the Applicants demonstrate the need for the proposed facilities, the Commission must determine whether there is evidence in the record demonstrating a more reasonable and prudent alternative to meet the demonstrated need.[51]

CapX Planning

57. During the twentieth century, Minnesota had two substantial upgrades to its bulk transmission system. In the early 1900's, planners designed a ring of 115 kV lines around the Twin Cities to deliver electrical power to the growing city population. In the 1950's and 1960's, a similar overall system expansion was undertaken with a 345 kV ring around the Twin Cities, and 230, 345 and 500 kV interconnections to neighboring utilities to enhance reliability and facilitate access to additional generation resources.[52]

---

[47] Minn. Stat. § 216B.1691, subd. 2a (a).
[48] Minn. Stat. § 216B.1691, subd. 2a (b).
[49] Minn. Stat. §§ 216B.169, subd. 1 (c), 216B.2426.
[50] Minn. Stat. §§ 216B.1612, subd. 1 and 5 (c), 216B.1691.
[51] *See,* Minn. R. 7849.0120.
[52] Ex. 1 at 3.25-3.26 (Application).

58. In 2004, a group of utilities jointly conducted engineering studies to develop a comprehensive plan to meet the anticipated increased demand for electricity in Minnesota and the surrounding area through the year 2020.

59. "CapX2020" was the name given to the initiative to study, develop, permit and construct transmission infrastructure to meet transmission needs through the year 2020. Initially, it included the Applicants, Minnesota Power, Missouri River Energy Services, and Otter Tail Power Company. "CapX2020" is short for "Transmission Capacity Expansion Initiative by the year 2020."[53]

60. In 2005, the CapX participants conducted a broad overview of the required transmission infrastructure investments needed to serve Minnesota and the surrounding states through 2020, referred to as the "Vision Plan" or "Vision Study."[54]

CapX Vision Study

61. In developing the Vision Study, the engineers examined the overall system of utilities serving Minnesota customers and the growth in demand for electricity anticipated by the year 2020. In 2005, the demand on the electrical system within the study region was 19,300 MW. The planning engineers gathered 2009 summer peak forecast data from the 2004 Mid-Continent Area Power Pool (MAPP) model to calculate a 2009 load level of about 20,200 MW. Using the MAPP Load and Capability Reports and comparable data for companies not included in the MAPP data, the planners calculated the forecasted demand to be about 26,500 MW by 2020, the "estimated growth" level.[55] The planners also calculated load growth approximately 30 percent lower, to reflect a "slow-growth" scenario. The slow-growth demand was estimated to be about 24,700 MW by 2020. The planning engineers used the estimated growth and slow growth levels to model the performance of the electrical system.[56]

62. Based on the system-wide estimates, the planners projected individual distribution substation annual peak power demand levels.[57]

63. To model the performance of the transmission network, both the magnitude and location of the demand for power by consumers and the generation to meet that demand are added to the computer simulation models. Planning engineers do not know where generation will be added to the system and must rely on forecasts of generation. The planners tested performance of the transmission system using several generation scenarios, and relied in part on the list of projects in the MISO queue at the time as an indication of potential generation development patterns.[58]

---

[53] Ex. 1 at 1.22 (Application).
[54] Ex. 1, Apx. A-1 (CapX 2020 Technical Update: Identifying Minnesota's Electric Transmission Infrastructure Needs ((October 2005)).
[55] Ex. 1 at 6.4-6.7 (Application); Ex. 48 at 3-5 (Lacey Direct).
[56] Ex. 1 at 6.7 (Application).
[57] Ex. 1 at 6.5 (Application); Ex. 21 (Response to NAWO/ILSR IR No.12).
[58] Ex. 1 at 6.15 (Application).

64. The planners also tested the sensitivity of the generation development patterns. They developed three generation scenarios to reflect how the location of potential generation development might influence electric power flows on the regional grid and the size and location of the transmission infrastructure needed to deliver the generation to customers.

65. Three generation scenarios were developed, "North/West Bias," "Minnesota Bias," and "Eastern Bias," each modeling about 6,325 MW of new generation, including 2275 MW of renewable energy generation.[59] In each scenario, 975 MW of renewable generation was allocated to Minnesota and 1,300 MW of renewable generation was allocated to surrounding states.

a. North/West Bias: In this model, much of the new generation was imported from Manitoba, North Dakota, South Dakota and Iowa. Of the 4,050 MW of non-renewable generation, 1,950 MW was allocated to Minnesota and 2,100 MW was allocated outside Minnesota.[60]

b. Minnesota Bias: In this model, the generation from outside of Minnesota was imported from North Dakota, South Dakota and Iowa. The entire 4,050 MW of non-renewable generation was allocated to Minnesota generation.[61]

c. Eastern Bias: In this model, the imported generation was largely from Wisconsin and Iowa. Of the 4,050 MW of non-renewable generation, 1700 MW was allocated to Minnesota and 2,350 MW to other states.[62]

66. Based on its analysis of where system overloads would occur when the estimated load growth or slow growth was added to the transmission system, the planners modeled several possible transmission additions. They determined that for each of the generation distribution scenarios, there were many necessary transmission additions in common. The "Common Recommended Facilities" are summarized in the Application, Figure 6-32.[63] The three CapX projects included in the Application were common to all scenarios.[64]

67. CETF contended that the Applicants have failed to model the type of generation that is likely to be transmitted by the CapX lines. In each of the three generation scenarios, 2275 MW of renewable energy was inserted into the model. The number was selected to meet the Renewable Energy Objectives in effect at that time, but is lower than the currently applicable, higher RES. At least two of the three

[59] Ex. 1 at 6.18-6.24 (Application).
[60] Ex. 1 at 6.19 (Application).
[61] Ex. 1 at 6.21 (Application).
[62] Ex. 1 at 6.23 (Application).
[63] Ex. 1 at 6.39 (Application).
[64] Ex. 1 at 7.1 (Application); Ex. 6 at 17 (Rogelstad Direct).

generation scenarios evaluated in the Vision Study included energy from coal generation. CETF contended that the scenarios are prohibited by the Minnesota Greenhouse Gas Emissions Control law,[65] and the Applicants have failed to show that the proposed projects can comply with the new law.[66]

68. The Vision Study included a mix of renewable and non-renewable generation in three areas to evaluate where new transmission facilities would be needed. The selection did not presume that the type of generation would occur as it was modeled. Rather, Applicants modeled a variety of scenarios to assure flexibility in meeting demand for any new generation.[67] There is no evidence that the projects' design could not serve a significant increase in the proportion of renewable generation to the RES level or above.

69. The Vision Study provided a long-range analysis and an analytical framework to guide project planning. Three additional engineering studies assessed and developed projects to address specific needs.[68]

<u>Southern Minnesota, Southwestern Wisconsin Reliability Enhancement Study (Rochester/La Crosse Study)[69]</u>

70. Local load studies were performed for Rochester and La Crosse/Winona to forecast future load growth and the ability of the current system to meet it. A number of alternatives were evaluated in each of the local load-serving studies. The study results demonstrated that a 345 kV option would provide the best long-term solutions and would be least-cost or require fewer additional lower voltage lines. Based on the results of the local studies, the Rochester/La Crosse Study was designed to evaluate 345 kV alternatives. As part of the study, the planning engineers evaluated possible sources for the 345 kV connection and concluded that the Twin Cites offered the strongest, closest connection.[70] Five options were considered and refined, leading to development of the proposed La Crosse Project, including the recommendation to construct a new substation at Hampton Corner to better separate the proposed line from existing 345 kV lines and decrease the risk of outage.[71]

71. The engineers concluded from the study that a new 345 kV line would provide reliable service to Rochester by increasing the peak load serving capability of the transmission system in the Rochester area to 821 MW, a level expected to meet need until 2041 to 2053.[72] Continuing the new 345 kV connection to the La Crosse area would serve that area's needs until approximately 2025.[73] The engineers also predicted

---

[65] Minn. Stat. § 216H.03.
[66] CETF Posthearing Brief at 19-23.
[67] Ex. 2B at 21-22 (Rogelstad).
[68] Ex. 6 at 11-12 (Rogelstad Direct).
[69] Ex. 1, Apx. A-2 (Mar. 13, 2006) (Application).
[70] *See* Ex. 1 at 5.1-5.11 (Application); Ex. 94 at 13-16 (King Direct).
[71] Ex. 94 at 16 (King Direct).
[72] Ex. 94 at 18 (King Direct).
[73] Ex. 94 at 22 (King Direct).

that a new 345 kV line would improve the overall system stability and reliability in southeastern Minnesota and into Wisconsin.[74]

72. Another study, the Regional Incremental Generator Outlet (RIGO) Study, evaluated generator outlet capacity in Southeastern Minnesota. As a result of the RIGO Study, three new lines are under consideration outside of this proceeding: 1) Pleasant Valley–Byron 161 kV line; 2) Pleasant Valley–Willow Creek 161 kV line; 3) Byron–Westside Energy Park 161 kV line. In addition to adding generation outlet capacity, these lines will also provide additional load-serving benefits to Rochester. Approval of these projects may affect Applicants' requested timing for the North Rochester–Northern Hills 161 kV line included in the La Crosse Project.[75]

<u>Red River Valley/West Central Minnesota Transmission Improvement Planning Study (TIPS Report) and the Red River Valley/Northwest Minnesota Load-Serving Transmission Study (TIPS Update</u>[76]

73. The TIPS Report and TIPS Update evaluated the transmission system needs in the Red River Valley area because that area experiences low system voltages during peak load conditions. For the northern zone of the Red River Valley, the best performing option was the 230 kV Bemidji to Grand Rapids line. Its certificate of need is addressed in a separate docket. For the southern zone of the Red River Valley, the best performing option was the proposed Fargo Project.[77]

74. In conducting the study, the planners evaluated the system by increasing load and observing when and where system deficiencies occurred. In order to balance the system, it modeled corresponding increases in generation. NAWO/ILSR correctly pointed out that the increased generation was modeled from existing large generation facilities (coal, hydro and nuclear power), and not from renewable energy.[78] However, the sites were selected solely to test the system under different generation scenarios, as a proxy for any additional generation that might be added. There were no assumptions about what generation would be added to the Fargo Project.[79]

75. In developing the Fargo Project, the planners considered three possible terminations that would increase service to the St. Cloud area and concluded that the Monticello Substation was the optimal endpoint, providing additional reliability improvements and avoiding a Mississippi River crossing.[80]

76. As part of the TIPS Update, the planners evaluated lower voltage lines, but concluded that none of them were adequate to address all of the needs identified in the study. Approximately nine 115 kV lines were required to achieve the capacity that

[74] Ex. 94 at 23 (King Direct); *See* Ex. 1 at Figure 5-4 – "Benefit Area of Twin Cities – La Crosse 345 kV Project" (Application).
[75] Ex. 83 at 10 (Stevenson Direct).
[76] Ex. 1, Apx. A-3 (Feb. 13, 2006) (Application).
[77] Ex. 1 at 5.11-5.12 (Application); Ex. 67 at 12-14 (Kline Direct).
[78] Ex. 1, Apx. A-3 at 16 (Application).
[79] T. 7 at 81 (Kline).
[80] Ex. 67 at 14 (Kline Direct); Ex. 70 at 4 (Kline Rebuttal).

one 345 kV line could achieve. Moreover, the 345 kV option provided additional support to the southern Red River Valley that lower voltage lines could not, with more direct ties between northwestern Minnesota and the Twin Cities.[81]

77. Engineers considered whether additional generation could provide load serving support but determined that it would be costly and inefficient compared to transmission from abundant generation resources to the west and east.[82]

Southwestern Minnesota – Twin Cities EHV Development Electric Transmission Study (Southwestern Minnesota Study or EHV Study)[83]

78. In 2003, the Commission granted certificates of need for transmission infrastructure in the Buffalo Ridge region for approximately 825 MW of generation outlet for proposed wind generation.[84] In 2007, the Commission granted certificates of need for three 115 kV transmission lines (BRIGO Projects) to increase the generation outlet for proposed wind generation by an additional 275 MW, a total of approximately 1,200 MW of generation outlet capacity from Buffalo Ridge.[85] The Southwestern Minnesota Study was undertaken to examine what additional improvements were needed to increase generation outlet capacity in southwestern Minnesota beyond 1200 MW.[86]

79. The Vision Study identified the need to construct a 345 kV transmission line in southwestern Minnesota. The Southwestern Minnesota Study was conducted to determine the details of integrating the 345 kV line into the existing transmission system and to identify the benefits of the line. It looked at termination points, intermediate connection points and transformer ratings, line design and other factors to evaluate performance and cost.[87]

80. After examining several options, including four primary options, the planning engineers concluded that the proposed Brookings Project was the best performing option because it provided the most additional outlet capability and would improve the electric system reliability in communities within the project area.[88]

[81] Ex. 67 at 17 (Kline Direct).
[82] Ex. 70 at 2-3 (Kline Rebuttal).
[83] Ex. 1, Apx. A-4 (Nov. 9, 2005) (Application).
[84] Docket No. E002/CN-01-1958, “825 MW Proceeding”.
[85] Docket No. E002/CN-06-154.
[86] Ex. 104 at 3-4 (Alholinna Direct).
[87] Ex. 1, Apx. A- 4, at 2 (Application).
[88] Ex. 104 at 2-5, 10-13 (Alholinna Direct).

Renewable Energy Standards

81. As part of its Renewable Energy Standards Report filed with the Commission, Minnesota Transmission Owners,[89] including the Applicants, provided a "Gap Analysis." It estimated the amount of additional renewable energy beyond what is currently produced or planned that will be required to meet the RES.[90] The Applicants prepared a similar analysis in support of the Application, estimating that utilities will need to generate or procure approximately 5,000 to 6,000 MW of wind generation by 2025. Applicants acknowledged that some utilities may use other forms of renewable energy to meet the RES.[91]

Additional Studies

82. Several additional studies to address transmission needs in Minnesota and the surrounding area have been conducted or were in progress at the time of the hearing in this proceeding.

83. On November 7, 2007, Minnesota transmission owners submitted their 2007 Minnesota Biennial Transmission Projects Report.[92]

84. Vision 2025: This study will examine the projected transmission facilities necessary to serve 2025 load levels in and around Minnesota, focusing on delivering the renewable energy required by the RES. It will look at scenarios with dispersed renewable generation, highly concentrated renewable project, and a scenario that assumes additional wind resources from the east.[93]

85. RES 2016: This study will identify the transmission alternatives needed to meet the RES milestones for the year 2016 and other generation projects needed to maintain system reliability. It will attempt to refine generation scenarios based on information from the MISO queue and three studies further described below: the DRG studies, the 230 kV Upgrade study, and the G&T Optimization Study.[94]

86. DRG Studies, Phase I and II: The purpose of Phase I was to determine whether up to 600 MW of dispersed renewable generation (DRG) could be sited without major transmission expansions. The Phase I Report was issued on June 16, 2008.[95] Phase II will consider whether an additional 600 MW of DRG can be added without major transmission expansions. Dispersed generation, as the term is generally used, refers to generation of 10 MW or less.[96] DRG is sometimes characterized as "C-BED,"

[89] Docket No. E999/ET-07-1028.
[90] Ex. 48 at 10-14 (Lacey Direct).
[91] Ex. 2, Apx. D-7 (Application).
[92] Ex. 54.
[93] Ex. 6 at 22-23 (Rogelstad Direct).
[94] Ex. 6 at 23 (Rogelstad Direct).
[95] Ex. 110, "Dispersed Renewable Generation Transmission Study," Volumes 1-3, prepared by Minnesota Transmission Owners, June 16, 2008, Docket No. E999/DI-08-649.
[96] Ex. 1 at 7.17 (Application); Minn. Stat. § 216B.169, subd. 1 (c).

a "community-based energy development" project. A C-BED project must have specified types of ownership.[97] DRG ownership is not restricted.

87. 230 kV System Upgrade Study: The Minnesota Valley – Blue Lake 230 kV transmission line limits transfer capability from the western portion of Minnesota to the east. The 230 kV System Upgrade Study will examine the transmission alternatives that eliminate this constraint on the system and allow additional development of renewable generation along the Buffalo Ridge.[98]

88. G & T Optimization: This study will examine the trade-offs of siting wind projects in high quality wind regions and siting the projects in lower quality wind regions with lower associated transmission costs. It will attempt to identify wind development models with both dispersed and concentrated wind generation.[99]

89. The Applicants contended that the studies in progress reinforce the results of the prior studies and the need for major transmission line construction.[100]

Overall Project Description

90. The CapX utilities identified four projects to be included in the first group of transmission improvements, collectively referred to as the Group 1 Projects. The Group 1 Projects include the La Crosse, Fargo and Brookings Projects included in this Application (the CapX projects), and a 230 kV transmission project proposed between Grand Rapids and Bemidji that is the subject of a separate proceeding.[101]

91. The results of the Vision Study demonstrated that the three proposed projects were common to all reasonable scenarios that were studied. In the analysis leading to the Application, several alternatives were considered, including different system configurations with different substations and voltages, upgrading or double-circuiting, no-build alternatives, and using generation as an alternative to transmission facilities. None of the alternatives were able to address the identified needs.[102]

92. The CapX projects are designed to address three types of need: to maintain the reliability of the transmission system while accommodating system wide growth, provide reliable community service in specified areas, and to accommodate new generation in the region and facilitate expanding renewable energy generation.[103]

---

[97] Minn. Stat. § 216B.1612, subd. 2.
[98] Ex. 6 at 23-24 (Rogelstad Direct).
[99] Ex. 6 at 24 (Rogelstad Direct).
[100] Ex. 6 at 20-25 (Rogelstad Direct).
[101] Certificate of need docket number: E017,E015, ET-6/CN-07-1222; Route permit docket number: E017, E015, ET-6/TL-07-1327.
[102] Ex. 1 at ch. 7 (Application).
[103] Ex. 1 at 3.31-3.32 (Application).

La Crosse Project Description

93. The La Crosse Project refers to the project as proposed in the Application and addressed in the Direct Testimony. The La Crosse Upsized Alternative refers to the alternative proposed by the Applicants in their Rebuttal Testimony. The Applicants are asking the Commission to grant a certificate of need for the La Crosse Project of the Upsized Alternative, but Applicants prefer the Upsized Alternative. Both the La Crosse Project and the Upsized Alternative are illustrated on Exhibits 24 and 25, Attachments C and D hereto. The Minnesota portion of the 345 kV line would be approximately 85 to 140 miles long, depending on the route selected.[104]

94. The Applicants propose a 345 kV line that runs from a proposed substation at Hampton Corner,[105] east of Farmington, to a proposed North Rochester substation that would connect the new line to the existing Prairie Island–Byron 345 kV line. The segment from Hampton Corner to North Rochester would be approximately 40 to 50 miles long. In the Upsized Alternative, the segment would be built with 345 kV/345 kV structures, with only one side strung and operated at 345 kV. [106]

95. Both the initial proposal and the Upsized Alternative include a 161 kV segment, approximately 10 to 15 miles long, from the proposed North Rochester Substation to the Northern Hills Substation, also in the Rochester area.[107]

96. The specifications for the remaining line segments depend upon the location selected to cross the Mississippi River. In the Application, four possible Mississippi River crossings were proposed at existing transmission line crossings or narrow areas with relatively few floodplain wetlands: 1) near Alma, Wisconsin; 2) near Winona; 3) near Trempealeau, Wisconsin; and 4) near La Crosse, Wisconsin.[108]

97. The Applicants withdrew the Trempealeau crossing from consideration because no existing transmission line crosses the area, field review showed more residences than expected, and the other three crossings have transmission lines in place.[109]

98. The Alma Crossing and the Winona/La Crosse Crossing are still under consideration. The latter two are referred to as the "Southern Crossing."

---

[104] Ex. 1 at 2.2 and Figure (Fig.) 2-1: "Map of Twin Cities – La Crosse 345 kV Project Area," (Application); Ex. 88 at 2 (Stevenson Rebuttal).
[105] The new Hampton Corner Substation would connect the proposed line to the existing Prairie Island – Blue Lake 345 kV transmission line in the vicinity of Hampton, Minnesota. Ex. 1 at 2.2 (Application).
[106] Ex. 1 at 2.2-2.3 (Application); Ex. 83 at 3 (Stevenson Direct); Ex. 88 at 2 (Stevenson Rebuttal); Attachments C and D to this Report.
[107] Ex. 1 at 2.2 (Application); Ex. 121 at 11-12 (Grivna Rebuttal).
[108] Ex. 1 at 2.2-2.3 and Figure 2-1(Application).
[109] Ex. 128 at 9-10 (Rasmussen Direct).

Alma Crossing

99. If the Alma Crossing is selected, the Project will include a 345 kV circuit from North Rochester to Alma on double-circuit structures. The estimated length of the Minnesota segment would be about 40 miles long. The Applicants would replace a portion of the Rochester–Alma 161 kV line with a new 345 kV/161 kV double circuit line, routed through Olmsted and Wabasha Counties. As proposed, the second circuit would operate at 161 kV from North Rochester to Chester, and an existing 161 kV circuit would continue to operate from Chester to Alma. From Alma, the Project will terminate at a La Crosse area substation with a line segment proposed as a single-circuit 345 kV line, operated on a double circuit structure with the Alma to La Crosse 161 kV line.[110]

100. The Project also includes a new 161 kV line from North Rochester to Chester, approximately 20 to 30 miles long.[111]

101. In the Upsized Alternative, the single 345 kV circuit from Hampton Corner to North Rochester would be placed on 345 kV/345 kV double-circuit structures. Also, the 345 kV line/161 kV double-circuit from North Rochester to Alma as proposed would be constructed as a 345 kV/345 kV double-circuit line, but the second circuit would be operated at 161 kV voltage and carry the existing parallel Chester–Alma 161 kV circuits until circumstances warrant an increase in the voltage. At that point the second circuit would operate at 345 kV, and the 161 kV line would be moved.[112]

102. The Applicants are not requesting the authority to operate a double-circuit 345 kV line at this time.

103. The Upsized Alternative does not change the proposed single-circuit 345 kV line from Alma to North La Crosse, placed with an existing Alma to North La Crosse 161 kV line on a double-circuit structure.[113]

Southern Crossing

104. As proposed, if the Project crossed the Mississippi River at Winona, the new 345 kV circuit from North Rochester would intersect with the Alma–North La Crosse 161 kV line in Wisconsin and the two lines would be double-circuited into the North La Crosse Substation. If the line from North Rochester crossed through La Crescent, it would not intersect with the Alma-North La Crosse line and would likely terminate at the La Crosse Substation. [114]

105. With the Southern Crossing, the 345 kV line from North Rochester to the east may be routed close to the Chester Substation. If it is, it may be more effective to

[110] Ex. 1 at 2.3 (Application); Ex. 83 at 3-5 (Stevenson Direct).
[111] Ex. 1 at 2.2 (Application); Ex. 88 at 2 (Stevenson Rebuttal).
[112] Ex. 121 at 11 (Grivna Rebuttal); Ex. 25.
[113] Ex. 1 at 2.3 (Application); Ex. 121 at 12 (Grivna Rebuttal).
[114] Ex. 1 at 2.3 (Application).

connect the 345 kV line at the Chester Substation, which would eliminate the need for the North Rochester to Chester 161 kV segment.[115]

106. In the Upsized Alternative, the segment from North Rochester to La Crosse would be constructed using the 345 kV/345 kV double-circuit configuration to match up with the Hampton Corner–North Rochester segment.[116]

107. The Applicants request that the Commission grant a certificate of need for the proposed project that authorizes a 161 kV line from North Rochester to Chester or the alternative direct connection of the 345 kV line at the Chester Substation, depending on the outcome of the routing across the Mississippi River in the route permit proceeding.[117]

108. As proposed, the Southern Crossing is the least cost option. OES recommended that the Commission select the Alma Crossing and the North La Crosse Substation termination in this proceeding rather than in the routing proceeding, because it was the least cost choice for the Upsized Alternative.[118] In addition, OES reviewed the Applicants' environmental information and concluded that the Alma Crossing would have less environmental impact and would be more acceptable to the U.S. Fish and Wildlife Service.[119]

109. The Alma Crossing has the least environmental impact, but the specific environmental impact of a selected route or its alternative is not known. Either endpoint is reasonable and may be selected during the routing proceeding.

110. Costs of the La Crosse Project: Applicants estimated that the La Crosse Project would cost between $364 and $374 million for the Alma Crossing and $355 to $363 for the Southern Crossing. For the Upsized Alternative, the estimate is $389 to $415 for the Alma Crossing (an increase of approximately $25 to $41 million) and $407 to $432 for the Southern Crossing (an increase of approximately $52 to $69 million).[120] The estimate will vary with the timing of construction, availability of construction crews and components, and the route selected by the Commission.[121]

111. Timing of the La Crosse Project: Applicants anticipate that each portion of the project will be completed in 2015, with the exception of the Northern Hills–North Rochester 161 kV line. Applicants request the flexibility to install that line by the third

---

[115] Ex. 83 at 7 (Stevenson Direct); Ex. 94 at 19 (King Direct).
[116] Ex. 121 at 12 (Grivna Rebuttal); Ex. 24.
[117] Ex. 83 at 8 (Stevenson Direct).
[118] Ex. 282 at 63 (Rakow Direct); Ex. 307 at 21, 23 (Rakow Surrebuttal). Dr. Rakow estimated that the cost differential between the two endpoints was about $12 million to $16 million, present value, for the proposed project and $25 million to $40 million, present value, for the Upsized Alternative; T. 25 at 58-59 (Rakow).
[119] Ex. 307 at 24-25 (Rakow Surrebuttal), citing Ex. 130 at 3 (Rasmussen Rebuttal), and Ex. 131.
[120] *See* Attachment F to this Report; Ex. 89 at 4 (Stevenson Surrebuttal).
[121] Ex. 83 at 11 (Stevenson Direct); *See* Attachment F to this Report.

quarter of 2011 if the RIGO projects are not approved, and to install it by the fourth quarter of 2012 if the RIGO projects are approved.[122]

112. No party opposed the proposed flexible in-service date for the Northern Hills–North Rochester 161 kV line. OES offered an alternative: that the Commission approve a 2011 service date, subject to modification in the event that the Commission approves the RIGO lines. This would allow modification of the service date to be more fully explored in the RIGO proceeding.[123]

113. Alternatives Considered by the Applicants: The Southeastern Minnesota/Southwestern Study explored several options for enhancing reliability in the area to be served by the La Crosse Project. These included options other than transmission construction, including generation, conservation, alternative energy and compliance with RES.[124] Higher and lower voltage lines were considered, as well as a double-circuit option from the Twin Cities to La Crosse.[125] OES concurred that a lower voltage alternative to the La Crosse Project would have higher capital costs and higher losses than the 161 kV alternative.[126]

114. In developing its proposal, the Applicants considered possible system upgrades. Applicants concluded that reconductoring could improve reliability for Rochester for five to six years but it was not a reasonable longer-term alternative.[127]

115. "No-Build" Alternative: The Applicants considered the "no-build alternative." Without the project, by 2011 Rochester may exceed the 362 MW maximum capacity level that is now supported by transmission and generation. La Crosse will be subject to the contingencies discussed in the load forecasts below, and the regional reliability will not be enhanced. Without some new transmission, there will be no improvement in reliability to either community.[128]

Fargo Project Description

116. Applicants seek a certificate of need to construct a series of 345 kV transmission line segments between Monticello, St. Cloud, Alexandria, and Fargo, North Dakota. The Fargo Upsized Alternative refers to the alternative proposed by the Applicants in their Rebuttal Testimony. The Applicants are asking the Commission to grant a certificate of need for either alternative, but Applicants prefer the Upsized Alternative. Both the Fargo Project and the Upsized Alternative are illustrated on Exhibit 22, Attachment A hereto. The overall length of the project would be approximately 210 to 270 miles, depending on the route selected.

[122] Ex. 83 at 9 (Stevenson Direct).
[123] Ex. 303 at 14-16 (Rakow Rebuttal).
[124] Ex. 1 at Apx. A-2 (Application) *See also,* Ex. 1 at 7.24 (Application).
[125] Ex. 94 at 23-25 (King Direct).
[126] Ex. 282 at 70, 82-83 (Rakow Direct).
[127] Ex. 1 at 7.24 (Application).
[128] Ex. 1 at 7.36-7.37 (Application); Ex. 94 at 25-26 (King Direct).

117. The first segment would run from the Monticello Substation at the Monticello Power Plant site to a new substation, Quarry Substation, on the western side of St. Cloud, approximately 30 to 40 miles. The new 345 kV line would connect with the existing 115 kV transmission system that serves the St. Cloud area.

118. The second segment would run from the Quarry Substation to a substation near Alexandria, connecting with the existing 115 kV transmission system serving west central Minnesota, including the City of Alexandria, either at an existing substation or a new substation near Alexandria. This segment would be approximately 60 to 80 miles long.

119. The third segment would run from Alexandria to a substation near Fargo, North Dakota. This segment would be approximately 120 to 150 miles long. Initially, the Applicants proposed that the new 345 kV line would terminate at the Maple River Substation, northwest of Fargo.[129]

120. During the proceeding, the Applicants requested the flexibility to terminate the northwestern end of the line at a new substation. The Maple River Substation is located within a growing residential area and it is congested with multiple transmission lines. A new substation farther from the City of Fargo may also simplify the routing of the new line. The Maple River Substation is the least cost option; the estimated incremental cost of building a new substation is $20 million.[130] Applicants request that the certificate of need allow for termination in the vicinity of Fargo without specifying the end point so that the Applicants can explore the most appropriate endpoint in conjunction with the North Dakota Public Service Commission and the route the line will take in North Dakota.[131]

121. No party objected to deferring identification of the northwestern termination of the Fargo Project to allow the benefits of a new substation to be weighed against the incremental cost.

122. The Applicants' Upsized Alternative for the Fargo Project is to construct the entire length of the route using 345 kV/345 kV structures, with only one side strung and operated at 345 kV.[132] This option was developed in response to the direct testimony of OES witness, Dr. Steve Rakow, and CETF witness, Larry Schedin. Both witnesses expressed their opinion that the Fargo Project should be larger than the original proposed project in order to provide the potential for additional transfer capability and long-term benefits. In his direct testimony, Mr. Schedin recommended that the Fargo Project be constructed as a double-circuit 345 kV configuration. In his direct testimony, Dr. Rakow recommended that the Fargo Project be constructed with a

---

[129] Ex. 1 at 2.5 and Figure 2-2: "Map of Twin Cities – Fargo 345 kV Project Area" (Application); Ex. 83 at 11-16 (Stevenson Direct).
[130] Ex. 312 at 3 (Kline Final Rebuttal).
[131] Ex. 312 at 1-4 (Kline Final Rebuttal).
[132] Ex. 121 at 10 (Grivna Rebuttal); Ex. 22.

single-circuit 500 kV configuration. Based on these recommendations, the Applicants reviewed their initial analysis and offered the Upsized Alternative.[133]

123. The Applicants are not requesting the authority to operate a double-circuit 345 KV line at this time. There are other facilities that limit double-circuit operation, particularly the Minnesota Valley–Blue Lake 230 kV line.[134] The Upsized Alternative includes double-circuit compatible structures so that the second circuit may be added when circumstances warrant. A single-circuit 345 kV line will provide reliable service to the southern Red River Valley, Alexandria and Saint Cloud. Operating a second circuit immediately would not significantly increase regional reliability.[135]

124. Timing of the Fargo Project: The projected service date for segments of the Fargo Project is 2011-2015. No party objected to the timing.

125. Cost of the Fargo Project: The estimated cost for the project is between $390 and $560 million, affected by the timing of construction, availability of construction crews and components, and the route selected by the Commission. The low end assumes a 210-mile route built as a single circuit. The high end of the range represents a 270-mile route with approximately 180 miles of double circuiting with existing transmission lines. The cost of the Upsized Alternative, with only one side strung and operated at 345 kV, is estimated to be $500 million to $640 million (an increase of $80 to $110 million).[136]

126. Alternatives Considered by the Applicants: The Applicants considered system configuration alternatives including higher voltage and lower voltage lines, upgrading or double-circuiting, and using generation as an alternative to transmission. Nine 115 kV lines would be needed to provide capacity comparable to the 345 kV line. Lower voltage lines were evaluated in the TIPS Update as well and were not adequate to meet the all of the identified needs: the 345 kV option will provide a new 345 kV source on the western side of the St. Cloud region and additional support to the southern Red River Valley, as well as strengthen the backbone transmission system in the region.[137]

127. No-Build Alternative: The Applicants also considered a "no-build" alternative and determined that the current level of transmission support in the southern Red River Valley, Alexandria, and St. Cloud was not capable of providing reliable service.[138]

---

[133] Ex. 121 at 10-12 (Grivna Rebuttal).
[134] Ex. 70 at 10 (Kline Rebuttal).
[135] Ex. 70 at 7-9 (Kline Rebuttal).
[136] Ex. 83 at 16 (Stevenson Direct); Ex. 88 at 4 (Stevenson Rebuttal) (The Applicants did not clarify whether a portion of the Upsized Alternative would be double-circuited with existing transmission lines). *See* Attachment F to this Report.
[137] Ex. 67 at 16-17 (Kline Direct); Ex. 70 at 2 (Kline Rebuttal); Ex. 1 at 7.24-7.25 (Application).
[138] Ex. 67 at 18-19 (Kline Direct).

Brookings Project Description

128. The Brookings Project includes a series of 345 kV segments between the Brookings County Substation in South Dakota, to a proposed new substation at Hampton Corner in the southeast corner of the Twin Cities, with a series of connections along the proposed transmission line with the existing transmission system. The Brookings Upsized Alternative refers to the alternative proposed by the Applicants in their Rebuttal Testimony. The Applicants are asking the commission to grant a certificate of need for either alternative but Applicants prefer the Upsized Alternative. Both the Brookings Project and the Upsized Alternative are illustrated on Exhibit 23, Attachment B hereto. The overall length of the project between Brookings County and the Twin Cities would be approximately 165 to 200 miles, depending on the route selected.[139]

129. The Applicants' primary purpose for the Brookings Project is to provide additional generation outlet from wind-rich southwestern Minnesota. It estimates that the project will increase generation outlet capability in Buffalo Ridge by 700 MW.[140]

130. The western-most segment of the project would be a 345 kV circuit between two existing substations, Brookings County Substation and Lyon County Substation near Marshall. This segment would be approximately 50 to 55 miles long.

131. The project would also include an approximately 25-mile, 345 kV circuit from the Lyon County Substation to the Hazel Creek Substation southwest of Granite Falls. This segment would replace an existing 115 kV circuit and would connect with existing transmission lines at the Hazel Creek Substation. If this Project is approved and the Big Stone II line is constructed, the Big Stone II line would also connect at the Hazel Creek Substation and could operate at 345 kV standards. The Hazel Creek Substation would also provide voltage support in the western part of the state as more wind farms are developed.[141]

132. The project includes an eight to ten mile segment between the Hazel Creek and Minnesota Valley Substations. This would replace a segment of the existing Lyon County–Minnesota Valley 115 kV circuit. In their Application, the Applicants proposed constructing this segment as a 230 kV line. However, during the proceeding, they revised their proposal to construct the line to 345 kV line standards and operate it initially at 230 kV until other upgrades in the area occur that require conversion to 345 kV. The Applicants anticipate that the Minnesota Valley to Blue Lake 230 kV line will need to be replaced or upgraded in the near future to accommodate the increased demand for renewable generation. Constructing the Hazel Creek to Minnesota Valley

---

[139] Ex. 1 at 2.6-2.8 (Application); Ex. 116 at 2-4 (Lennon Direct).

[140] Ex. 1 at 6.39, 6.50 (Application); Ex. 104 at 5 (Alholinna Direct).

[141] The 115 kV portion of the Hazel Creek Substation is being constructed as part of the Buffalo Ridge Incremental Generation Outlet (BRIGO) project. The 230 kV and 345 kV portions would be part of this project. Ex. 116 at 3 (Lennon Direct).

segment of this project at 345 kV standards will increase the capability of a Minnesota Valley-Blue Lake upgrade.[142]

133. The Project includes a 45-mile double-circuit 345 kV line between the Lyon County Substation and the Franklin Substation or a new substation in that area, and a 45-mile double-circuit segment between the Franklin area and a new Helena Substation in the vicinity of New Prague. The Helena Substation would connect the proposed double-circuit line and the existing Blue Lake–Wilmarth 345 kV line.[143]

134. There are two additional 345 kV single-circuit segments. One segment, approximately 20 to 30 miles long, would extend from the Helena Substation to the Lake Marion Substation in Lakeville, along the I-35 freeway corridor. The second segment, approximately 25 miles long, would extend from the Lake Marion Substation to the proposed new Hampton Corner Substation that is also included in the La Crosse Project.[144]

135. The Upsized Alternative would retain the proposed double-circuit segments of the project, from Lyon county to Franklin and Franklin to Helena, and upgrade all of the other segments to be double-circuit compatible: from Brookings to Lyon County, from Lyon County to Hazel Creek, from Hazel Creek to Minnesota Valley, and from Helena to Lake Marion and Lake Marion to Hampton Corner.[145]

136. At this time, the Applicants are requesting authority to operate double-circuit 345 kV lines only on the segments identified in the Application and not on the additional upsized segments.

137. Eastern Termination of the Brookings Project. CETF has challenged the proposed eastern termination of the Brookings Project at the new Hampton Corners Substation.[146] The Applicants have fully explained the proposed connection at Lake Marion but have not explained the benefit of the extension farther east to Hampton Corners.[147] However, the Lake Marion-Hampton Corners segment was included in the Southwestern Minnesota Study base plan and the related power flow analysis.[148] Based on this record, it is not clear whether the segment is necessary for regional reliability or to achieve 700 MW of generation outlet capacity.

---

[142] Ex. 104 at 13-14 (Alholinna Direct); T. 10 at 154-155 (Alholinna); Ex. 307 at 27 (Rakow Surrebuttal); Ex. 175 at 12 (Schedin Rebuttal).
[143] Ex. 116 at 3-4 (Lennon Direct).
[144] Ex. 1 at 2.6-2.8 and Figure 2-3: "Map of the Twin Cities – Brookings County 345 kV Project" (Application).
[145] Ex. 120 at 4-5 (Lennon Rebuttal). Ex. 116 at 4 (Lennon Direct); Ex. 23.
[146] CETF Reply Brief at 11.
[147] Ex. 104 at 8-10, 16 (Alholinna Direct).
[148] Ex. 1 at Apx. A-4 at 8-9, 25, 39. OES evaluated the Brookings Project configuration but there is no specific mention of the Lake Marion to Hampton Corners Segment. Ex. 282 at 65-68 (Rakow Direct).

138. Timing of the Brookings Project. The Project is expected to be completed and in service in 2012 for the Lyon County to Franklin and Franklin to Helena segments, and 2013 for all other segments.[149] No party objected to the timing.

139. Cost of the Brookings Project. As proposed, including the 345 kV line from Hazel Creek to Minnesota Valley, the estimated cost is $603.7 to $669.6 million.[150] The cost of the Upsized Alternative is estimated to be $654 to $725 million (an increase of $51 to $55 million).[151]

140. Alternatives to the Brookings Project. As part of the Southwestern Minnesota Study, a number of alternatives were evaluated, including lower voltage options. Also, after the study, planning engineers examined a single-circuit alternative, referred to as the "West Waconia Alternative," bypassing the proposed Franklin Substation connection. In addition, since the Southwestern Minnesota Study and the addition of new facilities, there has been further analysis to identify improvements that could provide significantly more outlet capability in Southwestern Minnesota. These studies confirmed both that the Brookings Project was the best-performing option, and identified the need to improve the Minnesota Valley to Blue Lake 230 kV line.[152]

141. No Build Alternative. The primary purpose of the Brookings Project, to increase generation outlet, cannot be met without new transmission capacity.

Common Characteristics of the Proposed Projects

142. A high voltage transmission line circuit consists of three phases, each at the end of a separate insulator string, all physically supported by structures. Each phase consists of one or more conductors. When more than one conductor is used to make up a phase, the term "bundled" conductors is used. Conductors are metal cables consisting of multiple strands of steel and aluminum wire wound together. There are also two shield wires strung above the electrical phases to prevent damage from lightning strikes. The shield wire may also include fiber optic cable for communication along the transmission line. A double-circuit transmission line carries two circuits or six phases and normally two shield wires.[153]

143. For all the 345 kV single-circuit and double-circuit transmission lines included in the three projects, Applicants propose to use two 954 Aluminum Conductor Steel Supported (ACSS) cables per phase or conductors of comparable capacity. For the 161 kV portions of the La Crosse Project, a single conductor using 795 ACSS cable or a conductor of comparable capacity will be used.[154]

---

[149] Ex. 311.
[150] The cost to upgrade from a 230 kV line to a single-circuit 345 kV line included in the Applicants' Direct Testimony is $3.7 to $4.6 million. Ex. 116 at 9 (Lennon Direct).
[151] *See,* Attachment F to this Report; Ex. 120 at 4-5 (Lennon Rebuttal).
[152] Ex. 104 at 11-18 (Alholinna Direct); Ex. 1 at 7.7, 7.25, and Apx. 4 at 8-9 (Application).
[153] Ex. 1 at 2.9-2.11 (Application).
[154] Ex. 1 at 2.10 (Application).

144. Applicants propose to use primarily single steel-pole structures for the 345 kV lines. Single-circuit steel-pole 345 kV structures vary in height from 105 to 150 feet depending on the span between structures. Double-circuit structures for either two 345 kV lines or a 345 kV and 161 kV line vary from 130 to 175 feet tall. Spans between structures can vary from 750 to 1,100 feet. Structures for a single-circuit 161 kV line are typically 70 to 105 feet tall with a 600 to 900 foot span.[155]

145. Both a single-circuit 345 kV line and a double-circuit 345 kV line require a 150-foot right-of-way. A 161 kV line requires 70 to 80 feet of right-of-way. The right-of-way may be narrower where it follows a pre-existing transmission line, road, or pipeline corridor.[156]

146. Applicants anticipate that the transmission towers will typically be single pole steel design, set on a concrete foundation approximately six to 12 feet in diameter and 15 feet deep.[157]

147. The Applicants estimate that the per-mile construction cost is $1,109,000 for a single-circuit bundled 345 kV line with a 954 ACSS conductor, and $1,880,000 for the double-circuit bundled 345 kV line with a 954 ACSS conductor.[158] Although the Applicants included cost estimates of the Upsized Alternative for each CapX project, the per-mile construction cost for the Upsized Alternative with single-circuit bundled 345 kV line strung was not included.

148. The estimated service life of the transmission lines may vary. Although assigned a limited life for accounting purposes, transmission lines are seldom completely retired. With the exception of severe weather such as tornados and ice storms, transmission lines rarely fail. The average annual availability of transmission infrastructure is in excess of 99 percent.[159]

149. Transmission lines have rare maintenance outages. The principal operating and maintenance cost for transmission facilities is the cost of inspections, usually done monthly by air and on the ground once a year. If wood structures are used, more detailed inspection is required about once every ten years. Annual operation and maintenance expenses average about $300 to $500 per mile. Substations require equipment and site maintenance.[160]

Lower Voltage Upgrades

150. When substantial high voltage additions are planned for the transmission system, the engineers analyze the performance of the lower voltage network to identify lower voltage circuits that may be overloaded by the addition of new facilities. The

---

[155] Ex. 1 at 2.10-2.11(Application).
[156] Ex. 1 at 2.9 (Application).
[157] Ex. 1 at 9.7 (Application).
[158] Ex. 186.
[159] Ex. 1 at 9.16 (Application).
[160] Ex. 1 at 9.16-9.17 (Application).

planning engineers develop a list of the underlying system improvements needed to support the high voltage additions. For CapX, the planning engineers used computer simulations with year 2012 system parameters and identified numerous lower voltage circuits that could be overloaded. The Applicants included a list of the lower voltage system upgrades required by the three projects and estimate that the upgrades will add $70 million to $100 million to the projects' cost. The upgrades were not broken out among the three projects.[161] The Upsized Alternative did not change the necessary lower voltage upgrades because no new circuits will be added immediately.[162]

Evaluation of Criteria for Certificate of Need

151. The criteria for evaluating an application for a certificate of need are set forth at Minn. Stat. § 216B.243, and elaborated at Minn. R. 7849.0120. Each of the rule criteria is addressed below. The Applicants have asserted that each CapX project is necessary to address three separate needs: to improve overall system reliability, to assure reliable service to local communities, and to increase generation outlet capacity.[163] The burden is on the Applicants to show that there is the asserted level of need.

A. The Probable Result of Denial Would Be an Adverse Effect Upon the Future Adequacy, Reliability, or Efficiency of Energy Supply to the Applicant, to the Applicant's Customers, or to the People of Minnesota and Neighboring States, Considering:

A (1). Accuracy of the Applicants' Forecast of Demand for the Type of Energy that Would be Supplied by the Proposed Facility.

<u>Regional Reliability</u>

152. Reliability standards are determined by the North American Electric Reliability Council (NERC). The reliability standard has two components: the system must be adequate to provide customers with a continuous supply of electricity at the proper voltage and frequency virtually all of the time, and the system must be "secure," which means that the bulk power system must have the ability to withstand sudden, unexpected disturbances from natural or man-made causes.[164]

153. NERC reliability standards require that a system be adjusted in order to withstand the "next" contingency. Thus, in its planning, when one component of the system is down, transmission planners examine the steps that must be taken to shift or reduce load if the loss of another component would result in overloading, even if the probability of the second loss is low.[165]

---

[161] Ex. 1 at 2.17-2.19 and Figure 2-14 (Application); T. 11 at 130 (Lennon).
[162] Ex. 121 at 16 (Grivna Rebuttal).
[163] Ex. 1 at 3.25-3.26 (Application).
[164] Ex. 257 at 6-7 (Ham Direct) (citations omitted).
[165] Ex. 56 at 21 (Webb Direct); T. 5A at 31-35 (Webb).

154. Minnesota's need for additional transmission facilities is determined in part by the role that its interconnected facilities play in supporting regional reliability of the transmission system. Each of the three projects terminates in communities just across the Minnesota border and the three projects will support those communities as well as Minnesota communities. While the emphasis in the application is service to Minnesota customers, the nature of the transmission system requires an analysis that is regional. Minnesota has consistently imported electricity for many years (in 2006, about 16 percent). Appropriate interstate transmission can provide Minnesota with reliable and reasonably priced energy.[166]

155. The Federal Energy Regulatory Commission (FERC) has authority over the transmission of electric energy in interstate commerce and wholesale sales of electricity, including regulating transmission rates and practices and authorizing and overseeing the operation of regional transmission organizations. Under the Energy Policy Act of 2005, it is also responsible for oversight of NERC reliability standards. MISO oversees and coordinates regional transmission planning and services and manages access to the transmission grid in the Midwest region. It is actively involved in studying transmission needs and expansion requests in order to serve existing and forecasted load and to meet demand for renewable energy mandates.[167]

156. Minnesota utilities file Integrated Resource Plans (IRPs) with the Commission approximately every two years, predicting demand and energy consumption over a 15-year forecast period.[168]

157. The Mid-Continent Area Power Pool (MAPP) is a voluntary association of Upper Midwest electric utilities and other electric industry participants. Its functions include responsibility for facilitating open access of the transmission system. Each year Minnesota utilities submit to MAPP a Load and Capability Report, which is a 10-year forecast estimating a utility's seasonal customer demand and what generation facilities the utilities will use to meet that demand.[169]

158. Each forecast estimate discussed below is summarized on Revised Figure 6-6, Attachment E to this Report.

[166] Ex. at 1.4 (Application); Ex. 257 at 4-5 (Ham Direct); T. 22 at 169 (Ham).
[167] Ex. 56 at 4 (Webb Direct); T. 5A at 80 (Webb).
[168] *See* Minn. Stat. § 216B.2422.
[169] Ex. 1 at 6.5 (Application); Ex. 48 at 6 (Lacey Direct).

Applicants' Forecasted Load Growth

159. Forecasting uses historical information to make reasonable assumptions about the future. Changes in the economy, including a recession, may slow the anticipated growth, pushing out the year in which upgrades to the transmission system may be required, but there is no evidence that load growth will substantially slow or stop.[170]

160. The Applicants' estimate of demand derives from the Vision Study. The study area selected for the Vision Study was primarily based on the geographic boundaries of the service territories of utilities that serve customers in Minnesota. Those systems include all of Minnesota and portions of North Dakota, South Dakota, Iowa, Wisconsin and Upper Michigan.[171]

161. To develop the forecast for the year 2020, planning engineers gathered 2009 summer peak forecast data from the 2004 MAPP model. They estimated the load level for 2009 to be 20,201 MW.[172] Then they applied growth rates taken from MAPP Load and Capability Reports or, for three companies, Alliant Energy (West), GRE and Minnesota Power, from either their IRPs or the company. Based on the projected growth rates, the planning engineers estimated the demand to rise to about 26,500 MW by 2020, an increase of about 6,300 MW. The planners characterized this as the "expected growth" scenario.[173]

162. Expected growth was estimated at 2.49 percent annually from 2009 through 2020, which is a decrease from the actual growth rate in the early 2000's of 2.64 percent.[174]

163. In addition, the planning engineers ran an analysis assuming about 4,500 MW of growth, an approximately 29 percent reduction, described as the "slow growth" scenario. Under the slow growth scenario, peak system wide demand would reach approximately 24,700 MW in 2020.[175]

164. In 2007, in preparation for the Application, the Applicants looked at the 15-year forecasts included in the IRPs filed by the utilities with the Commission. As part of this Application, the Commission required the Applicants to provide a summary description of the IRP filings and Commission Orders for each participating utility. The summary is included in Appendix C-6 of the Application.[176] Since some utilities do not file IRPs, the Applicants also reviewed 2006 MAPP Load and Capability data. Applicants compared the Vision Study forecasts with the IRPs and MAPP Load and Capability Reports approved by the Commission in 2005 and 2006. These confirmed

[170] T. 15 at 119-121 (Alders).
[171] Ex. 1 at 6.3 and Fig. 6-1 (Application); Ex. 6 at 13 (Rogelstad Direct).
[172] Ex. 48 at 4-5 (Lacey Direct).
[173] Ex. 48 at 4-6 (Lacey Direct).
[174] Ex. 1, Apx. A-1, at 1, 5. (Application).
[175] Ex. 48 at 4-6 (Lacey Direct).
[176] Ex. 2, Apx. C-6 (Application).

that the Minnesota utilities anticipated significant load growth between 2009 and 2020.[177] Using the combination of data from the two types of reports, Applicants projected a range of growth from 4,095 to 4,904 MW.[178]

165. In response to Information Request No. 7 from NAWO/ILSR, Applicants prepared additional estimates to provide a demand forecast that incorporated the 1.5 percent conservation goals enacted in 2007.[179] Each utility has an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales. The conservation goals were not in effect when the Vision Study was conducted. The revised estimated load forecast was approximately 25,708 MW (medium) to 27,708 MW (high) by 2020, about 100 MW higher than the calculations used in the Vision Study.[180]

166. The Applicants assert that the CapX projects are part of the plan to strengthen the transmission network to meet the forecasted demand under both the revised high and medium scenario.[181]

<u>OES Forecast Analysis</u>

167. OES reviews load forecasts as a part of many Commission proceedings. OES concluded that the Applicants' peak demand forecasts were reasonable.[182]

168. OES witness Ham also conducted an independent analysis to verify the forecast. He obtained information from the Midwest Reliability Organization (MRO) 2007 Series summer peak model to update the 2004 MAPP data used by the Applicants. The updated figure was 22,228 MW peak demand in 2009, higher than the 20,201 forecast in the Vision Study.[183] Then Mr. Ham applied a growth rate from the most recently approved or accepted IRP from Minnesota utilities to obtain year 2020 summer peak demand.[184]

169. Based on this information, Mr. Ham estimated 2020 peak demand to be 27,060 MW, about 572 more than the Applicants' expected growth forecast in its Vision Study (26,488 MW), and in between the high and medium revised forecasts (27,708 and 25,708). The results of this analysis were consistent with Mr. Ham's review of recent IRPs filed by Xcel Energy, Minnesota Power, Otter Tail Power and Interstate Power and Light, and with GRE's 2005 IRP. Mr. Ham concluded that these five companies serve the majority of Minnesota customers and all need additional capacity

---

[177] Ex. 1 at 6.7-6.8 (Application); Ex. 48 at 7-8 (Lacey Direct); Revised Figure 6-6, Attachment E to this Report.
[178] Ex. 1 at 6.9 (Application).
[179] Minn. Stat. § 216B.2401.
[180] Ex. 53 at 8 (Lacey Rebuttal); Revised Figure 6-6, Attachment E to this Report. The 2009-2020 increase was smaller than the base study because the base forecast for 2009 was higher.
[181] Ex. 48 at 10 (Lacey Direct); Ex. 6 at 17 (Rogelstad Direct).
[182] Ex. 257 at 14, 19 (Ham Direct); Ex. 274 at 1-2 (Ham Surrebuttal).
[183] Ex. 264; Revised Figure 6.6, Attachment E to this Report.
[184] Ex. 265.

and energy in the 2010-2015 timeframe. This was further corroborated by Mr. Ham's review of the MAPP Load and Capability Report issued on May 1, 2007.[185]

170. In the course of this proceeding, Mr. Ham revised his calculations to take into account calculations by OES witness Davis of load reductions necessary to meet the 2007 conservation goals.[186] Since the historical conservation rates have been significantly lower than 1.5 percent, this was a reasonable proxy for the amount of additional energy the utilities could be expected to conserve through 2020.[187] Assuming that all the utilities met the 1.5 percent conservation goal, the cumulative incremental demand savings would be 1,370 MW. With 1.0 percent energy savings, the cumulative incremental demand savings would be 703 MW.[188]

171. In addition to the projected conservations savings, Mr. Ham also took into account OES witness Peirce's calculation of the renewable energy generation needed to meet the 2007 RES Statute.[189]

172. The RES Statute requires utilities to make a good faith effort to generate or procure "eligible energy technologies" in specified amounts by specified dates. OES calculated the amount of RES needed to meet those goals, using four scenarios:

a. energy savings of 1.0 percent and a wind capacity factor or 30 percent;

b. energy savings of 1.0 percent and a wind capacity factor of 40 percent;

c. energy savings of 1.5 percent and a wind capacity factor of 30 percent;

d. energy savings of 1.5 percent and a wind capacity factor of 40 percent. [190]

173. The calculation took into account the utility's forecast, multiplied by the RES for each year in the forecast period, and then subtracted out the estimated amount of renewable energy each utility would have obtained by 2010.[191]

174. The wind capacity factor is the percentage of time that the facility's generation can be counted toward load serving, and the 30 to 40 percent rates for wind generation are consistent with the experience of the CapX utilities.[192] Because wind is the largest renewable resource in Minnesota, OES used the wind capacity factor in the calculation.[193]

---

[185] Ex. 257 at 9 (Ham Direct).
[186] Minn. Stat. § 216B.242, subd. 1.
[187] Ex. 215 at 2 (Davis Direct). OES regards the goal as aggressive but achievable. *Id.* at 2-3.
[188] Ex. 215 at 12-13 (Davis Direct). Calculations for local communities are discussed below.
[189] Minn. Stat. § 216B.1691.
[190] Exs. 253-255.
[191] Ex. 261 at 6-17 (Peirce Direct); Ex. 247 at 4 (Peirce Surrebuttal).
[192] Ex. 244; Ex. 2 at Apx. D-6 (Application); Ex. 261 at 17 (Peirce Direct).
[193] Ex. 231 at 19 (Peirce Direct). Ms. Peirce explained why she anticipated that most of the energy to meet the RES will come from wind energy. Ex. 247 at 1-3 (Peirce Surrebuttal).

175. The nameplate capacity of generation is the total amount of energy produced when the generator is operating at capacity. The "accredited" capacity is the amount of the nameplate capacity that can be relied upon to produce generation at full capacity within a given hour. The rates range from 10 percent to 36 percent, but most CapX utilities cite rates between 10 and 15 percent. OES used a rate of 13.5 percent, which fell in that range and was the rate used by Xcel Energy, the company with the largest wind capacity.[194]

176. Based on these calculations, OES projected that Minnesota utilities will need an additional 3,160 to 4,927 MW of wind generation beyond their current commitments to meet the RES goals.[195] Increased conservation would not decrease the need for transmission to support renewable energy.[196]

177. Taking into account both conservation and the renewable energy calculations in his analysis, Mr. Ham concluded that the Minnesota utilities will need 1,269 MW to 2,094 MW of non-renewable generation to serve Minnesota customers reliably through 2020, a total of 4,621 to 6,817 MW of additional generation.[197]

178. The Applicants' projected load figures may actually understate the forecast demand that should be used for planning purposes because significantly more peak demand is likely to be needed under extreme weather conditions. Thus, some projects for local areas may be needed sooner than projected.[198]

179. No other parties offered a load forecast. Each forecast in the record is at or above the 24,701 MW slow-growth forecast in the Vision Plan upon which the engineering analysis was conducted. Both the Applicants' revised medium growth forecast of 25,708 MW and the OES estimate of 25,690 to 26,357 MW exceed the level used in the Applicants' analysis.[199]

180. Although the Applicants have not completed an analysis of facilities needed at a level of forecasted growth lower than 24,701 MW in the slow-growth model, neither do they anticipate that the three projects included in the Application are sufficient to meet that need. Instead, the Applicants assert that these projects are a necessary first step to meet the forecasted load growth.[200]

MISO Analysis of Forecast

181. MISO conducted an independent evaluation of the CapX project. It relied upon the load forecasts provided by the load-serving utilities because its experience is that those forecasts are the most accurate and have been reviewed by state regulators. It also reviewed the reasonableness of the forecasts against trends, other models, and

[194] Ex. 231 at 20 (Peirce Direct).
[195] Ex. 247 at 4 (Peirce Surrebuttal). .
[196] Ex. 231 at 26 (Peirce Direct); Ex. 215 at 1 2-16 (Davis Direct); Ex. 195 at 8 (Schedin Rebuttal).
[197] Ex. 274 at 2 (Ham Surrebuttal); T. 22 at 152 (Ham); Revised Figure 6.6, Attachment E.
[198] T. 22 at 151-153 (Ham).
[199] Revised Figure 6-6, Attachment E.
[200] T. 1B at 70-71 (Rogelstad).

NERC studies to assure that the forecasts were sufficiently accurate for MISO to handle its planning responsibilities.[201] MISO also considered the CapX projects as part of its overall transmission expansion planning processes. MISO concurs that each of the CapX projects will be needed within the next five to seven years for overall system reliability and security.

182. In determining whether a specific project should be included in its expansion plan, MISO staff typically meets with a broad group of stakeholders including transmission owners, transmission customers, end-use customers, generation developers, and state regulators. Since the cost of transmission projects that provide regional reliability is spread broadly across MISO, the customers have a significant interest in assuring that the proposed transmission projects are needed and the best cost alternative. The CapX projects have been reviewed by the MISO stakeholders and included in MISO's base plans upon which longer term plans are being developed and analyzed.[202]

183. When the hearing record closed, the CapX projects were still under review by MISO, with expected board approval as part of its 2008 expansion plan.[203]

184. Each of the three CapX projects will strengthen the reliability of the transmission system, ensure adequate energy supplies to the Twin Cities and surrounding areas, enhance efficient transfer of power throughout MISO and support competitive pricing of electricity.[204]

Objections to the Load Growth Projections

185. NAWO/ILSR and CETF claimed that the Applicants' long-range forecast was no longer accurate, in part because Applicants failed to take into account recently enacted conservation goals and unanticipated declining consumption.[205]

186. Applicants provided updated forecasts that were verified by OES, taking into account both enhanced conservation and the RES. MCEA witness Schedin predicted that lower load growth may actually increase the need for the CapX projects to supply the necessary generation outlet to meet the RES because it is difficult to site large amounts of renewable generation near load.[206]

187. Reductions in load forecast could affect the MISO models, but because of the identified size of the overloads, and areas of voltage collapse, substantial reductions in the forecast ("a very wide, very, very significant change in forecast level") or

[201] T. 5A at 82-83 (Webb).
[202] Ex. 56 at 10 (Webb Direct); T. 5B at 29-30 (Webb).
[203] Ex. 56 at 11-12 (Webb Direct). In its Reply Brief, MISO stated that the CapX Projects were included in MTEP 08, approved by its Board on December 4, 2008.
[204] Ex. 56 at 37 (Webb Direct).
[205] NAWO/ILSR Post-hearing Brief at 15, 21, citing T. 21 at 138 (Davis); CETF Posthearing Brief at 31.
[206] Ex. 195 at 8-9 (Schedin Rebuttal).

significant addition of new generation would be required to significantly affect the need for the CapX projects.[207]

188. NAWO/ILSR contended that no engineering studies support the Applicants' lower forecasted demand. That is inaccurate. The loads included in the Vision Study modeling, 24,701 MW (slow growth) and 26,488 MW (expected growth), were within the range of Applicants' revised forecasts of 25,708 MW (medium) and 27,708 MW (high). Although the 2009 load forecast rose (reducing the size of the load growth), the modeling loads were consistent with the revised 2020 forecasts. Also, the studies showed that the system was not reliable at a level below the forecasted levels. Mr. Rogelstad's judgment was that the proposed projects would be necessary to address system-wide growth as well as local community needs even if demand growth through 2020 were as low as 2,000 MW, far below any of the estimates.[208]

189. CETF asserted that the 1.5 percent energy conservation estimates from Exhibit 217 could be applied to the lower demand forecasts in Exhibit 265, the approved integrated resource plan forecasts, reducing projected growth in 2020 to 3,163 MW.[209] OES, the party that prepared those exhibits, did not agree with CETF's calculations. The 1.5 percent conservation calculation in Exhibit 217 was based on forecasted load. If the forecasted load were reduced, the resulting 1.5 percent calculation would also be lower. To take the higher conservation calculation and subtract it from a lower forecasted load would create an artificially low forecast. The OES analysis yielded significantly higher forecasts than the number posited by CETF.[210]

190. Some parties and members of the public contended that the CapX projects were not necessary to serve Minnesota load and were a pretext to ship bulk power across Minnesota from the resource-rich states west of Minnesota to large urban centers to the east of Minnesota.[211]

191. The engineers credibly testified that the engineering studies evaluated Minnesota load-serving and not bulk transfer. MISO's witness, Mr. Webb, stated that its studies did not model injection of power from western source points to load east of Minnesota to determine whether the CapX project would accomplish that goal, but instead, it evaluated the reliability of constraints to serving Minnesota load over the next five to seven years. In his opinion, as designed and tested, CapX has minimal capacity for bulk transfer of power. [212]

192. OES witness Rakow concurred that bulk transfer was not economical and that the vast majority of new capacity would serve Minnesota load.[213]

---

[207] T. 5A at 92-93 (Webb).
[208] T. 2B at 84, 87; T. 3 at 83-85 (Rogelstad).
[209] CETF Posthearing Brief at 17-18.
[210] OES Reply Brief at 29-30.
[211] NoCapX Posthearing Brief; UCAN Posthearing Brief.
[212] T. 5B at 58-64 (Webb).
[213] T. 25 at 73, 80 (Rakow).

193. NAWO/ILSR asserted that the Applicants failed to consider the potential energy savings from implementation of "Smart Grid" technology. Smart Grid technology has several components, including technology that provides more direct communication from fuel source to end use, providing immediate price information to encourage greater conservation and better performance of the distribution and transmission systems. NAWO/ILSR contends that Smart Grids can be expected to produce a 30 percent reduction in residential peak demand and ten percent reduction in residential energy consumption. NAWO/ILSR cites Xcel Energy projections of an additional 25 percent reduction in residential peak demand when Smart Grid is combined with "supply side" distributed generation.[214] However, its source is "Xcel Energy Smart Grid: A White Paper."[215] At this time, the Smart Grid innovations are still in development. The purpose of the pilot project is to assess the benefits and the corresponding costs.

194. No specific Smart Grid alternative has been developed that would address each of the needs set forth in this Application, nor are there identified costs for any specific alternative.[216] Neither the Applicants nor OES considered that the results from Smart Grid demonstration projects were sufficiently quantifiable to include a corresponding reduction in demand in this proceeding. OES witness Davis included the possible use of Smart Grid as one of the tools for utilities to meet Demand Side Management (DSM) goals, but concluded that it was not sufficiently tested to include a specific forecast adjustment.[217]

195. The La Crosse Project will improve regional reliability by creating a second 345 kV source to the Rochester area. In the event that the Prairie Island – Byron 345 kV line is out of service, the Hampton–North Rochester 345 kV transmission line could be relied upon to provide service.[218]

196. The Fargo Project will increase the generation outlet across the North Dakota Export (NDEX), which may facilitate development of increased renewable generation in North Dakota and Minnesota, and it will provide back-up for the Dorsey-Forbes 500 kV line and Center-Jamestown 345 kV line.[219] It will provide a 345 kV source on the western side of the St. Cloud region and additional support to the southern Red River Valley, and strengthen the backbone transmission system in the region.

197. The Brookings Project will facilitate lower cost or renewable generation, ensure compliance with the NERC reliability standards, and relieve congestion on the transmission grid. The 825 MW provided by the Southwestern Minnesota project approved in 2003 and completed in 2008, and additional capacity associated with the BRIGO lines approved in 2007, provide a total of 1200 MW. That capacity is insufficient to accommodate all of the wind generation projects proposed in the Buffalo Ridge area.

---

[214] Ex. 148 at 46 (Michaud Rebuttal).
[215] Ex. 145.
[216] Ex. 133 at 2-3 (Alders Surrebuttal).
[217] T. 21 at 73, 127, 129 (Davis).
[218] Ex. 98 at 4 (King Rebuttal).
[219] Ex. 67 at 16-17 (Kline Direct); Ex. 70 at 2 (Kline Rebuttal); Ex. 199 at 12-13 (Schedin Surrebuttal).

The Brookings Project will provide an additional 700 MW of generation outlet, a total of approximately 1,900 MW, with a high capacity line from wind collection points to the Twin Cities. The Brookings Project will create an additional path from the Buffalo Ridge area to the east and avoid two current limiters on the system.[220]

198. In conducting its review of the CapX projects, MISO analyzed alternatives but did not identify any that would better serve either regional reliability or increased generation outlet for renewable energy.[221]

199. NAWO/ILSR pointed out that the level of review necessary to fully analyze the Applicants' power flow and stability studies requires money and expertise that the intervenors cannot duplicate.[222] MCEA witness Schedin expressed similar concerns but noted that the project had been extensively reviewed by MISO and by personnel from the utilities. Mr. Schedin's limited review of selected output, his acquaintance with the professionals running the models and their qualifications, and the growing need for renewable generation outlets, reinforced his confidence in the accuracy of the modeling that supports the application. He recommended that the utilities and other model operators set up a consistent audit trail procedure in the future to allow careful review of their inputs and analysis.[223]

200. In summary, the Applicants have demonstrated that the CapX projects will improve the regional reliability of the transmission system to meet projected load growth.

Community Reliability

201. The need for improved community reliability led to development of the La Crosse Project and the Fargo Project. Although not part of the impetus for the project, the Brookings Project is also able to improve community service.[224]

Projected Load Growth for Rochester

202. The Applicants evaluated the load growth for the Rochester area. In 2006, the peak load at the Rochester area substations reached 330 MW. The reliable maximum transmission capacity available to serve the Rochester area is 181 MW. The available local generation is also about 181 MW. With the existing transmission support and local generation, the system can reliably serve 362 MW. Based on the forecasts, this load level will be exceeded in approximately 2011. With the failure of either generation or transmission, the level will be exceeded much sooner. There are also deficiencies on the system during off-peak, high transfer conditions. This has resulted in operating guidelines that limit the power that can flow south on the Prairie Island –

[220] Ex. 104 at 3-5 (Alholinna Direct).
[221] T. 5B at 72-73 (Webb).
[222] Ex. 148 at 21-22 (Michaud Rebuttal).
[223] Ex. 199 at 11-12 (Schedin Surrebuttal); *see also,* Exs. 182, 183.
[224] Ex. 1 at 4.1-4.2 (Application).

Byron 345 kV line, to protect against overloading the system in the event of an outage along the Byron–Adams 345 kV line. [225]

203. Other projects are under consideration to serve Rochester. Based on the RIGO Study, Xcel Energy has developed a package of three new 161 kV lines (RIGO lines) that would alleviate certain limitations on the transmission system The primary purpose of the RIGO lines is to increase generation outlet in southeastern Minnesota. The RIGO lines will also increase the capacity of the transmission system to 246 MW. With the addition of these facilities, the transmission system could adequately serve the area load until 2015.[226]

204. In addition, Dairyland Power intends to reconductor the Rochester–Adams 161 kV line to facilitate wind outlet. With the reconductoring and the installation of the RIGO lines, the system could reliably serve load to 468 MW, a level expected to be reached in approximately 2018.[227]

205. The Applicant's projected 2020 load may be overstated. OES Witness Davis calculated the effect of the 2007 conservation goals which reduced the forecasted local need in Rochester by approximately 30 MW in 2020. Even with this reduction, the load exceeds the projected capacity of the transmission system. [228]

206. A new Hampton Corner 345 kV source enhances regional reliability by creating a second 345 kV source to the Rochester area. The Hampton Corner–North Rochester segment could reliably provide service if the Prairie Island–Byron 345 kV line is out of service. With the addition of the Hampton Corner–North Rochester segment of the La Crosse Project, the system would reliably serve load until approximately mid-century.[229]

207. The Applicants' projections assumed that current Rochester generation would be going down as facilities are scheduled to retire. In conducting its analysis, the Applicants assumed that there would be no local generation to serve load in 2020.[230]

208. OES examined information concerning the estimated supply capacity in 2009, expected additions and retirement of supply side resources, and each utility's purchases and sales of generation capacity.[231] RPU has plans to retire its current generation in the Rochester area by 2015 (a reduction of approximately 67 MW) and to seek permits for a new West Side Substation, connecting to new 161 kV lines. RPU is

[225] Ex. 94 at 5-8 (King Direct); Ex. 219 at 1.
[226] Ex. 94 at 21 (King Direct). Applicants' projected need: 426 MW. OES calculation with 1.5% energy savings: 411 MW (Ex. 219 at 1); T. 8 at 164 (King).
[227] Ex. 94 at 21 (King Direct). Applicants' projected need: 492 MW. OES calculation with 1.5% energy savings: 461 MW (Ex. 219 at 1).
[228] Ex. 219.
[229] Ex. 98 at 4 (King Rebuttal).
[230] Ex. 94 at 8-9 (King Direct).
[231] Ex. 220 at 2-3 (Shaw Direct); Ex. 222.

also considering adding gas generation, although no specific proposal was included.[232] None of the potential projects have received permits or have a date certain for coming into service.

209. NAWO/ILSR, CETF, and NoCapX correctly pointed out that if the level of generation in Rochester is maintained, the RIGO lines will provide reliable service to Rochester until 2026. OES concurred.[233] At the time that the record in this proceeding closed, the application for a certificate of need for the RIGO lines had not been filed and there were no specific plans for new generation. Although installation of RIGO would postpone the need for the La Crosse Project to serve Rochester load, the La Crosse Project will also provide alternative 345 kV support to Rochester that will meet its needs for many years.[234]

210. For Rochester and other communities, NAWO/ILSR asserted that the Applicants had failed to assess whether the implementation of Smart Grid technologies would adequately address community reliability. As discussed above, Smart Grid approaches have not been sufficiently tested to include them in load forecasts, nor have the costs of implementing Smart Grid technologies in the local communities been estimated. Although Smart Grid holds promise for reducing load growth, the benefits are not yet quantifiable.

211. OES calculations of load growth with 1.5 percent conservation confirmed that Rochester's projected load would exceed critical load in 2011 and thereafter without additional generation or transmission capacity.[235]

212. Some members of the public expressed support for improving the reliability of service to Rochester. It has been several years since the city's infrastructure has been updated, and added capacity will encourage future economic development.[236]

Projected Load Growth for La Crosse

213. At the present time, power to the Winona/La Crosse area is provided by four 161 kV lines and the capacity of the system is dependent in part on the generation plants in the area.[237] The forecast data show that the demand for power will exceed the capacity of the transmission system in 2009 under certain contingencies and will exceed its capacity by 68 MW in 2015. The reliability is significantly dependent on the operation of coal plants in Alma and Genoa. The French Island units in La Crosse also provide part of the generation serving this area. Two of the French Island units, 13 MW each,

---

[232] Ex. 222 at 11 of 23; T. 22 at 19-22 (Shaw). Ex. 157, "Report on the Electric Utility Baseline Strategy for 2005-2030 Electric Infrastructure," Summary, Parts II and IV, June 2005, prepared for RPU. Does not include specific planning commitments.
[233] OES Reply Brief at 43, citing T. 9 at 111 (King).
[234] Ex. 99 at 2 (King Surrebuttal).
[235] Ex. 219 at 1.
[236] Public Hearing Transcript (Pub. T.),Tab 19, Koshire, Reichert (Rochester); Tab 18, Eckerman (Rochester); Pub. Exs. 33, 34.
[237] Ex. 1 at 4.7-4.16 (Application); Ex. 94 at 9-12 (King Direct).

burn refuse and operate on weekdays when trash is picked up. The other two units, 70 MW each, run on fuel oil which is expensive and possibly limited by environmental permitting. Thus, the transmission planners did not consider the 70 MW units to be routinely on line in their planning. The outage of any of the coal plants also significantly affects the amount of power than can be delivered to the area. [238]

214. The studies that preceded the application concluded that a 345 kV line would provide the best support to meet forecasted load of 640 MW in the Winona/La Crosse area through 2023.[239]

215. OES revised the load estimate, taking into account the impact of the 2007 conservation statute. It estimated load at 539 MW with 1.5 percent conservation savings. OES calculations confirmed that La Crosse's projected load would exceed critical load in 2010 and thereafter without additional generation or transmission capacity.[240]

216. The Applicants updated their modeling to include 2011 summer peak load from the 2066 MAPP Series. That MAPP series also included anticipated transmission infrastructure improvements.[241]

217. The transmission system is sufficient to withstand the loss of the Genoa to Coulee transmission line if the French Island Units 3 and 4 are operating, but the system is not sufficient to prepare for the contingent loss under NERC standards of any additional facility. The planning engineers reasonably concluded that the French Island Units 3 and 4 could not be counted upon to be operating at all times.[242]

218. NAWO/ILSR asserted that the lower voltage system could be upgraded to improve reliability and load serving, and could be substantially reinforced with additional cost-effective generation at French Island. However, it did not provide any evidence of the cost to repower the French Island units or whether the 161 kV upgrades would be sufficient to meet the projected need under NERC contingencies. [243]

<u>MISO Review of the La Crosse Project</u>

219. MISO reviewed the projected loadings and voltage conditions in the Rochester and La Crosse areas for the 2011 summer peak period and also at somewhat higher levels. Like the Applicants, MISO anticipated that some of the available local generation in Rochester may be retired, but even with all generation available, there would be numerous line overload conditions. The potential overloading of the Byron to Maple Leaf 161 kV line was of particular concern.

---

[238] Ex. 1 at 4.9-4.16 (Application).
[239] Ex. 94 at 14 (King Direct); Ex. 98 at 7 (King Rebuttal).
[240] Ex. 219 at 2.
[241] Ex. 11 at 3-4 (Response to NAWO/ILSR IR 16, Mar. 26, 2008).
[242] T. 9 at 123-123 (King); Ex. 103.
[243] Ex. at 23 (Michaud Direct) ("(t)he alternative of adding just the 161 system upgrades, which appear to be those shown on p. 144 of Appendix A-2 for a cost of $32 million, may be a cost effective solution to the 2020 time frame load serving issues.")

220. Several scenarios that led to overloading involved either two line outages or one line outage and significant generation off line. Planning for the second contingency is consistent with NERC standards. MISO concluded that a new North Rochester substation with a step down transformer between the 345 kV Prairie Island to Byron 345 kV line and the proposed 161 kV line from North Rochester to Northern Hills would parallel the Byron transformer and the Byron to Maple Leaf 161 kV line. [244]

221. Although the Applicants have proposed to run the 345 kV line from a new Hampton Corner substation rather than from Prairie Island, each provides the same load-serving benefits.[245]

222. MISO considered the alternative of installing a second Byron transformer and new Byron to Northern Hills 161 kV line. This would provide similar benefits to Rochester at similar cost but would not address reliability in the La Crosse area.

223. MISO also reviewed the projected reliability in the La Crosse area and identified several reliability issues at the load projected for the 2011 summer peak, 492 MW. Each of these potential problems is summarized by MISO witness Webb. The addition of a strong 345 kV source into the area will relieve the worst loading conditions for many years.[246] MISO considered the system operation with the 70 MW peaking plants on line and rebuilding the 161 kV lines in the area, but these options did not provide the same level of support to meet NERC standards or did not provide comparable ability to accommodate future load growth.

224. MISO concluded that the La Crosse Project would address future reliability in the Twin Cities and surrounding area and improve local reliability in Rochester and La Crosse for many years.[247]

225. NAWO/ILSR and CETF correctly pointed out that the contingencies identified by Mr. Webb assume that the two French Island 70 MW peaking plants are off line, and most of the scenarios also project loss of both a transmission line and one of the large coal generating plants, either Alma or Genoa.[248]

226. Although CETF and NAWO/ILSR opposed granting the certificate of need for the La Crosse Project, they apparently accept that a number of the proposed upgrades to the 161 kV system, including some that are already completed and may be included in the Project cost, are necessary to assure the system's reliability.[249]

227. At the public hearing in Winona, Brian Krambeer, President, Tri-County Electric Cooperative, spoke in favor of the La Crosse Project to ensure reliable service to its customers and support development of renewable energy projects in southeastern

---

[244] Ex. 56 at 27-28 (Webb Direct).
[245] Ex. 11 at 3 (Response to NAWO/ILSR IR 16 (Rev. & Supp.), Mar. 26, 2008).
[246] Ex. 56 at 30-31 (Webb Direct).
[247] Ex. 56 at 32 (Webb Direct).
[248] Ex. 56 at 31 (Webb Direct).
[249] *See* CETF Proposed Findings of Fact 288 and 292, citations omitted, and footnote 274, citing Ex. 11 and Ex. 1, Apx. A-2 at 144 (Application).

Minnesota.[250] Tim Noeldner, a professional engineer employed by Wisconsin Public Power, Inc., also lent support to the La Crosse Project.[251]

228. Jai Johnson, La Crosse City Council Member, opposed CapX and asserted that it will impede the development of local projects, including renewable energy.[252] Dr. Carrie Jennings, Eureka Township Supervisor, supported small, local generation to improve the electrical system and enhance the local economy.[253]

229. MCEA witness Schedin concluded that the certificate of need for the La Crosse Project was justified to serve the local area needs of Rochester and La Crosse.[254]

Load Growth in the Red River Valley

230. The TIPS Update identified reliability issues in the northern and southern Red River Valley. The application for a certificate of need for the Bemidji to Grand Rapids 230 kV transmission line addresses reliability issues for the northern Red River Valley through 2020.[255]

231. In the TIPS Update, planning engineers evaluated the southern Red River Valley actual system peak in the 2003/2004 winter period, and determined that the system could reliably serve an additional 330 MW beyond the peak, a total of 1,360 MW. The engineers determined that the loss of the Center–Jamestown portion of the Center–Jamestown–Maple River 345 kV line would severely limit the capacity of the system and cause unacceptably low voltages in some areas. They determined that local generation was relatively small and scarce and not a viable option. In 2005, 2006, and 2007, the Center–Jamestown segment experienced unplanned outages. Substation data also showed that the system's capabilities could be exceed in 2016 to 2019.[256]

232. During the summer of 2007, additional forecasting was done for the CapX application, including an evaluation of load forecasts for individual utilities in the Fargo study area.[257]

233. CETF claimed that the forecasted winter peak demand through 2020 was overstated.[258] However, OES witness Davis took into account 1.5 percent conservation savings and projected that the forecasted load would exceed the critical load level by 2011 or earlier.[259] No witness offered calculations that refuted Mr. Davis. As noted

---

250 Pub. T., Tab 16, Krambeer (Winona); Pub. Ex. 30B.
251 Pub. T., Tab 17, Noeldner (Winona); Pub. Ex. 31.
252 Public Comment (Pub. Comm.), Johnson, filed 7/31/08, #5405084.
253 Pub. Comm. Jennings, filed 9/22/08, #5518689. *See also,* Ninneman, Cure, filed 10/07/08, #5554862.
254 Ex. 177 at 35 (Schedin Direct).
255 T. 6 at 161 (Kline).
256 Ex. 1 at 4.16-4.26 (Application); Ex. 67 at 3-7 (Kline Direct).
257 T. 6 at 146 (Kline).
258 CETF Post-hearing Brief at 42.
259 Ex. 215 at 15 (Davis Direct); T. 21 at 61 (Davis).

above, the load forecasts used by Applicants and calculated by OES may actually understate the need because the forecasts did not take into account extreme weather.[260]

Load Growth in Alexandria

234. The Alexandria area was also analyzed in the TIPS Update. The conclusion was that the 115 kV system needed improvement between 2011 and 2014 to meet growing demand, the latter date dependent upon the availability of a 7.8 MW generator at the Poleyard Substation. Loss of any one of the three 115 kV lines serving the area could result in low voltages when demand exceeds 171 MW, the level expected by about 2011.[261]

235. Al Crowser, general manager, Alexandria Light & Power, testified at the public hearing in support of the CapX projects. He stated that the Alexandria area is at a "seam" between the control areas of Otter Tail Power and Xcel Energy and has experienced occasional voltage dips and voltage swings from ice storms in the eastern Dakotas and the Red River Valley. He was pleased to see the utilities cooperating with each other to better serve the area. Mr. Crowser also noted that there is significant interest in conservation and load management, but that it is not estimated to exceed projected load growth.[262] Brian Zavesky, Senior Transmission Engineer, Missouri River Energy Services (MRES), Sioux Falls, South Dakota, also supported the CapX projects. His company is a supplemental supplier of power to Alexandria Light and Power, and believes efforts to upgrade the current system are a "band-aid" until the CapX projects can be constructed. He also commented on the difficulty that wind developers have gaining interconnection to the transmission system.[263]

236. NAWO/ILSR argued that the Alexandria area need can be met through 2020 with a combination of demand side management, using Smart Grid and other incentives, and the benefits of the proposed Bemidji–Grand Rapids 230 kV line.[264] However, the Smart Grid technologies are not fully tested nor did NAWO/ILSR propose a specific alternative for Alexandria, with estimated costs and timeframe.[265]

237. OES calculations of load growth with 1.5 percent conservation confirmed that Alexandria's projected load could exceed critical load by 2015 and thereafter without additional generation or transmission capacity.[266]

[260] T. 22 at 153 (Ham).
[261] Ex. 1 at 4.26-4.30 (Application); Ex. 67 at 8-9 (Kline Direct).
[262] Pub. T., Tab 3, Crowser (Alexandria), and Pub. Hrg. Ex. 2.
[263] Pub. T., Tab 3, Zavesky (Alexandria), and Pub. Hrg. Ex. 3. *See also,* Tab 4, Banke, Melrose, and Pub. Hrg. Ex. 4.
[264] Ex. 148 at 49-50 (Michaud Rebuttal).
[265] *See e.g.,* T. 21 at 127, 129 (Davis).
[266] Ex. 219 at 4.

Load Growth in St. Cloud

238. The projected need for new transmission to St. Cloud was not opposed by any of the parties except NoCapX and UCAN, although neither of the two offered any evidence into the record that would counter the Applicants' evidence of need. There has been significant growth in population in the St. Cloud area. The Verso Paper Mill, with its associated load of 89 MW, is served through the St. Regis Substation. In the event of loss of the double-circuit line between Benton County and Granite City during summer peak loading, the Granite City–St. Regis 115 kV radial line is automatically tripped off, and the loss of the double circuit line also limits the capacity of the system to serve remaining load. Although capacity can be increased with the operation of the Granite City gas-fired generators, the generators are less reliable than transmission and less economical. Other contingencies will also limit the system's ability to serve customers.[267]

239. OES calculations of load growth with 1.5 percent conservation confirmed that St. Cloud's projected load will significantly exceed critical load by 2010 and thereafter without additional generation or transmission capacity.[268]

240. NAWO/ILSR and CETF agreed that the Applicants have demonstrated the need for the Monticello–St. Cloud segment of the Fargo Project because the projected load growth exceeds any reasonable estimate of current capacity and costs justify the expansion.[269]

241. Limiting the Fargo Project to this segment would not provide the necessary regional support to the southern Red River Valley or Alexandria and would not increase the NDEX or increase the potential for generation outlet.[270]

242. MCEA concluded that the Fargo Project would supply local areas and provide support for the Red River Valley.[271]

MISO Review of the Fargo Project

243. MISO studied three general load serving areas along the path of the proposed Fargo Project: the Red River Valley Area, Alexandria Area, and the St. Cloud Area.[272]

244. In the Red River Valley, the winter peaking load was estimated to be 2,200 MW in 2011 and 2,367 MW in 2016. There is about 565 MW of generation within this area and the Jamestown-Maple River 345 kV line and 230 kV lines provide the balance of the power. If the 345 kV line and one of the 230 kV lines are out of service,

---

[267] Ex. 1 at 4.30-4.35 (Application); Ex. 67 at 9-12 (Kline Direct); *See also,* Pub. T., Tab 4, William F. Banke, General Manager, Stearns Electric Assn., (Melrose) and Pub. Exh. 4.
[268] Ex. 219 at 5.
[269] Ex. 148 at 49 (Michaud Rebuttal); CETF Post-hearing Brief at 44-45.
[270] *See* Ex. 74 at 1-2 (Kline Surrebuttal).
[271] Ex. 177 at 23 (Schedin Direct).
[272] Ex. 56 at 17 (Webb Direct).

the generation would not be sufficient to provide reliable service. By 2016, 545 MW (23 percent reduction in load) would be needed after a single transmission line outage. By providing a second 345 kV supply, the Fargo Project would assure that the system would remain secure for the loss of the single existing 345 kV supply, and would also address other reliability issues projected by 2016.[273]

245. Other alternatives were considered, including adding voltage support and a second 230 kV line from Boswell to Winger. This would address potential voltage collapse but with less margin and would not address projected need in Alexandria and St. Cloud. Adding a 345 kV extension or a new line from Dorsey to Maple River was also considered but would require the same or more miles of construction and would not serve Alexandria or St. Cloud.[274]

246. The Alexandria area is served by three 115 kV lines. By 2011, loss of any two of the lines would result in critically low voltage, and by winter peak of 2016, even a single contingency loss would reduce voltage to the point where it could not sustain any load. Although the probability of losing two lines is low, there is insufficient generation available to provide support. By 2016, 27 to 33 percent of the total load would have to be shed after the first line loss to withstand the loss of the next contingency and maintain adequate voltage.[275] Alternatives, including an extension of 230 kV line, were considered. Although new 230 kV support would improve reliability through 2011, the Fargo Project would accommodate an additional 23 years of estimated load growth.[276]

247. In St. Cloud, MISO identified several possible contingency conditions by 2011.[277]

248. MISO concluded that the Fargo Project would provide long-term local reliability to the Red River Valley, Alexandria, and St. Cloud, and address future reliability needs in the Twin Cities and surrounding areas for many years.[278]

249. At the public hearings, the Sauk Center Public Utilties Commission,[279] the City of Melrose,[280] and Moorhead Public Service[281] also supported the CapX projects.

Projected Local Load Growth for the Brookings Project

250. Although the primary purpose of the Brookings Project is to increase outlet generation capacity, it will also improve local reliability. The Southwestern Minnesota

[273] Ex. 56 at 18-19 (Webb Direct).
[274] Ex. 56 at 20 (Webb Direct).
[275] Ex. 56 at 21-22 (Webb).
[276] Ex. 56 at 24 (Webb Direct).
[277] Ex. 56 at 24 (Webb Direct).
[278] Ex. 56 at 32 (Webb Direct).
[279] Pub. T., Tab 4, Sunderman (Melrose), and Pub. Ex. 6.
[280] Pub. T., Tab 4, Harren (Melrose), and Pub. Ex. 7. *See also,* Pub. Ex. 11, photos submitted in support, by Jim Nichols.
[281] Pub. Ex. 9.

Study was conducted after the Vision Study to determine the details of integrating the Brookings Project into the existing transmission system and to identify the initial benefits of the line, independent of the overall plan. The Southwestern Minnesota Study did not include a detailed examination of local load-serving, critical load levels or load projections, but local benefits were identified.[282]

251. Specifically, the proposed 345 kV/115 kV transformer at the Franklin Substation would strengthen the power supply for the New Ulm and Redwood Falls area and the Olivia and Bird Island area. The Lyon County to Hazel Creek 345 kV segment will strengthen service to Granite Falls and its surrounding area.[283] In addition, the connection to the Lake Marion Substation would provide significant load-serving support in the growing areas of Scott and Dakota Counties.[284] The planning engineers determined that this project would be a better alternative than increasing the number of north to south 115 kV lines through developed areas.[285]

252. Although the Applicants have demonstrated that the Brookings Project will generally strengthen service to local communities, there are no specific load forecasts upon which to determine the ability of current facilities to meet the need.[286]

253. MISO determined that the Brookings Project will support underlying lower voltage transmission systems along its route which will reduce loadings on the lower voltage circuits and provide better service quality to local transmission systems.[287]

254. In summary, the Applicants demonstrated that the CapX projects will improve the reliability of the transmission system to serve local load.[288]

<u>Generation Outlet Capacity</u>

255. The Applicants have stated that the CapX projects are needed in part to increase the generation outlet capacity for renewable resources and meet the RES. MISO, MCEA and OES projected strong demand for additional transmission to provide generation outlet, especially for wind generation. Although all parties supported implementation of the RES, some disagreed that the CapX projects are the best way to address this need. MCEA, NAWO/ILSR and CETF supported conditions on the certificates of need that would assure that new generation outlet capacity is dedicated to wind energy.

256. The La Crosse Project is expected to enhance the deliverability of wind generated power from southeastern Minnesota. There are approximately 12,000 MW of projects seeking to interconnect in southeastern Minnesota. The three RIGO lines are

---

[282] Ex. 1 at 4.36-4.40, Apx. A-4 at 2, 35 (Application).
[283] Ex. 1 at 4.38-4.39, Apx. A-4 at 35 (Application); Ex. 104 at 7-8 (Alholinna Direct).
[284] Ex. 1 at 4.39, Apx. 4 at 36; Ex. 104 at 8-10 (Alholinna Direct).
[285] Ex. 1 at 4.39-4.40 (Application); Ex. 104 at 8 (Alholinna Direct) *See also,* Ex. 282 at 17-18 (Rakow Direct).
[286] *See* Minn. R. pt. 7849.0120 A.
[287] Ex. 56 at 36 (Webb Direct); T. 4 at 145 (Webb).
[288] Ex. 257 at 19 (Ham Direct); Ex. 274 at 2 (Ham Surrebuttal); Ex. 56 at 9-10, 32, 36 (Webb Direct).

designed to help meet the RES 2012 milestone, providing approximately 700 to 900 MW of generation outlet capability in southeastern Minnesota. At those levels, much of the power would be absorbed in the Rochester area and the remainder would flow north on the Byron–Prairie Island 345 kV line to the Twin Cities. The net flow on the Byron–Prairie Island 345 kV line would still be north to south. [289] Once the connected generation exceeds 900 MW, the level expected in the 2012-2015 timeframe, generation in excess of 900 MW could not be reliably delivered to the Twin Cities in the event the Prairie Island–North Rochester 345 kV segment were out of service. If the RIGO lines are approved, the La Crosse Project will allow capability beyond 900 MW, provide another path for the power, and assist utilities in meeting the 2016 milestones.[290]

257. The Fargo Project will cross a wind-rich area in northwestern Minnesota and eastern North Dakota. The transmission outlet capability from North Dakota is currently limited. The electrical boundary between Minnesota and North Dakota and South Dakota (NDEX) is identified by the Department of Energy as a congested area that limits wind generation development. The Fargo Project is expected to increase transfer across the NDEX limit by approximately 350 MW, which will support additional outlet for generators in northwest Minnesota and southeastern North Dakota.[291]

258. The DRG Study showed that the existing transmission system provided virtually no opportunities for dispersed generation in the part of Minnesota traversed by the Fargo Project, and, more generally, showed the difficulty of adding dispersed generation sites to the high-voltage system.[292]

259. The Brookings Project is expected to provide approximately 700 MW of additional generation outlet capacity in the Buffalo Ridge area.[293] It is a key component to the development of renewable energy resources.

260. CETF, NAWO/ILSR and NoCapX contended that the modeling of generation that was used in the studies is inconsistent with the asserted need of the Brookings Project to serve renewable generation. In the models, generation was injected from sites where coal projects are located. By planning the projects to run from areas near the coal plants, these parties are concerned that both the Fargo and Brookings Projects will serve coal generation rather than renewable energy. As Dr. Kildegaard explained it, “the presence or absence of conveniently located transmission affects the economic viability of current and future generation assets, not unlike the way in which a highway from a center city affects real estate values in the suburbs along the new route.”[294] He pointed out that the cost of generation, including the cost for coal and for wind, is geographically specific.[295] Thus, the proposed corridor for a new

[289] Ex. 98 at 2-3 (King Rebuttal).
[290] Ex. 98 at 1-3 (King Rebuttal).
[291] Ex. 1 at 6.49 (Application): Ex. 67 at 12 (Kline Direct); Ex. 70 at 7 (Kline Rebuttal).
[292] Ex. 100 at 49; T. 10 at 86-87 (Alholinna); Ex. 176 at 2-5 (Gramlich Surrebuttal).
[293] Ex. 104 at 2, 5 (Alholinna Direct).
[294] Ex. 166 at 5 (Kildegaard Direct).
[295] *Id.*

transmission line must take into account the economics of the generation that it intends to serve.

261. The Applicants are aware of the changing regulatory environment and the increased requirements to provide electricity from renewable energy sources. The Applicants have not claimed that the transmission lines will serve only renewable energy, but both the Fargo and Brookings Projects will access wind-rich areas where wind development is well underway.[296] Although the transmission lines could serve new coal generation, in the current regulatory environment, it is more likely that most of the new outlet capacity will serve wind generation.

262. Projects that seek interconnection must file a request with MISO and are placed on the MISO interconnection queue. In May 2008, MISO had approximately 60 generator interconnection requests along or near the counties where the Brookings Project will be routed: 15,940 MW of requests in the general area, including over 7,460 MW within the counties along the preliminary project route. MISO has performed studies to determine the effect the Brookings Project would have on the ability of generators to interconnect and reliably deliver output to the grid.[297] Fifty-eight wind interconnection projects representing 4,358 MW of generation have been studied with the Brookings Project as part of the base case. For some of these projects, short-term interconnection solutions were identified. For others, the Brookings Project was an essential component of interconnection.[298] Based on the studies, MISO witness Webb stated that it is "highly probable" that the 700 MW of increased transfer capacity in the Brookings Project would be used by wind capacity.[299]

263. OES, CETF[300] and MCEA concurred that the Brookings Project is critical to increase wind generation outlet from the Buffalo Ridge and to support utilities' compliance with the RES milestones. MCEA concluded that all three projects would create new generation outlet capacity.[301]

264. In summary, the Applicants demonstrated that the CapX projects would improve the generation outlet capacity of the transmission system.

Benefits of the Upsized Alternative

265. Applicants concluded that the Upsized Alternative for each project would better serve longer term system expansion, provide additional flexibility, and make better use of transmission corridors. Since the proposed projects cross environmentally

[296] T. 2B at 21-22 (Rogelstad); T. 5A at 64 (Webb).
[297] Ex. 56 at 33-34 (Webb Direct).
[298] Ex. 56 at 35 (Webb Direct).
[299] T. 5A at 68 (Webb).
[300] CETF Proposed Findings of Fact, etc. at #417, citing T. 3 at 216-218 (Lacey); Ex. 53 at 11-12 (Lacey Rebuttal).
[301] Ex. 177 at 5-7 (Schedin Direct); Ex. 176 at 4-5 (Gramlich Surrebuttal).

sensitive areas, building double-circuit structures now may avoid new river crossings in the future.[302]

266. The Applicants conceded that the La Crosse, Fargo and Brookings Projects as proposed are sufficient to meet forecasted load-serving needs. Most of the benefits associated with the larger structures included in the Upsized Alternative cannot be realized until other future transmission projects occur and are beyond the 2020 planning horizon.[303]

267. For the La Crosse Project, a second 345 kV circuit could provide access to economical power generated to the south or east. It could also increase delivery options during high wind, low load periods and increase import capability in times of high load and no wind.[304] Although it was suggested that a second circuit could increase the level of the Wisconsin-Minnesota Export, there was no evidence of the current or anticipated export level. There is no evidence of current constraints or planning in progress to suggest that the need for a second circuit is imminent.

268. For the Fargo Project, there is strong evidence that transmission is currently constrained and that an upgrade beyond 345 kV is needed to increase the NDEX. [305]

269. For the western segments of the Brookings Project, the high number of proposed wind projects in western Minnesota and northeast South Dakota on the MISO queue, and the potentially high transfer demand from the west, are likely to increase the need for future upgrades.[306] For the eastern segments of the Brookings Project, a second 345 kV circuit could provide the beginning of an outside-ring 345 kV loop for the Twin Cities load, decrease system loss and transfer line flow more efficiently. Although adding the second circuit from Helena to Hampton Corner is not part of the Applicant's proposal at this time,[307] the Upsized Alternative will provide infrastructure that could reduce the number of new rights-of-way required in the future.[308]

270. OES, MISO and MCEA favored the potential benefits that the Upsized Alternative offers. OES concluded that the Upsized Alternative was a reasonable and prudent alternative to the three projects as proposed.[309] MISO witness Webb stated that its "standard practice" in other parts of the Midwest to build transmission that is

---

[302] Ex. 121 at 32-34 (Grivna Rebuttal).
[303] Ex. 121 at 9 (Grivna Rebuttal).
[304] Ex. 121 at 40-41 (Grivna Rebuttal).
[305] Ex. 70 at 10 (Kline Rebuttal).
[306] Ex. 121 at 37-38 (Grivna Rebuttal).
[307] Ex. 104 at 17 (Alholinna Direct) ("Planning engineers determined that [the Brookings to Lyon County] segment did not need to be double circuit 345 kV because a second circuit would not improve system performance or increase generation outlet….(T)he transfer capability of the transmission system is limited not by the capacity of this segment or the line impedance, but rather is limited by the adjacent and underlying transmission systems.")
[308] Ex. 121 at 39 (Grivna Rebuttal).
[309] OES Posthearing Brief at 10, citing Ex. 307 at 8, 9, 21 (Rakow Surrebuttal).

double-circuit compatible.[310] MCEA concluded that the investment is prudent only if increased capacity is committed to renewable energy. Each of them concluded that the Upsized Alternative was the best alternative and would provide a cost-effective foundation for a growing transmission system while at the same time minimizing the amount of additional right-of-way that may be required as the system grows.

A (2). Effects of the Applicants' Existing or Expected Conservation Programs and State and Federal Conservation Programs.

271. This rule criterion is interpreted in light of the language of Minn. Stat. §216B.243, subd. 3, which states: "No proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures."

Public Support for Conservation, Demand Management, and Renewable Energy

272. NAWO/ILSR and CETF contended that targeted conservation and load management could reduce the community reliability need for the CapX projects.[311] Several members of the public also advocated that the utility companies should more aggressively pursue conservation, demand management, and renewable energy instead of transmission lines.[312] Glenn Bennett of Lowry, who has served as a director of Runestone Electric, an electric distribution cooperative, testified that additional conservation, such as motion detector switches and time-of-day monitoring, should be implemented before additional transmission lines are constructed.[313] Irv Balto of Chaseburg also advocated for increased conservation and peak demand management.[314] Virgil Fuchs has a wind turbine on his property that supplies his needs, and he has power to sell to Runestone Electric. He favors greater reliance on local renewable energy.[315]

273. Some participants encouraged greater focus on the strong wind resources in Minnesota and its potential benefits to the state as an alternative.[316] Other individuals asserted that the CapX projects were not large enough to harness the state's wind energy.[317]

274. Members of the public also preferred that a combination of conservation, demand management and small generation located closer to load be pursued rather

[310] T. 5B at 52-53 (Webb).
[311] NAWO/ILSR Posthearing Brief at 21; CETF Posthearing Brief at 31.
[312] *See, e.g.*, Publ. T., Tab 18, Erickson (Rochester); Tab 15, Beckman, Leck, Soule (Cannon Falls); Tab 13, Diffley, Kaufenberg, Mealman (Lakeville); Tab 11, Minar (New Prague); Pub. Comm. Timmerman, filed 8/08/08, #5464476; Pohl, filed 8/21/08, #5464478; Quinlivan, filed 7/31/08, #5405095; Iremonger, filed 10/06/08 # 5551881; *see also,* Pub. Ex. 20.
[313] Pub. T., Tab 3, Bennett (Alexandria).
[314] Pub. Comm. Balto, filed 8/8/08, #5417357.
[315] Pub. T., Tab 4, Fuchs (Melrose).
[316] Pub. T. Tab 1, Wernsing (Moorhead); Tab 14, Tyler (Cannon Falls).
[317] Pub. T. Tab 5, Bruer (Clearwater); Tab 8, Fenske (Marshall).

than high voltage transmission lines.[318] Linda Halley of Eureka Township requested that the Commission deny the certificates of need and require alternatives that relied more heavily on conservation and C-BED wind projects.[319] Julie Anderson, Denise Radcliffe, Caroline van Schaik, Stephen Quinlivan, Mackenzie Sigler and others shared this view, and believe that transmission lines are representative of antiquated ideas about energy use and planning.[320] Some anticipate that new technologies will slow the growth of electricity.[321]

275. There were specific objections raised by Margaret Levin on behalf of the Sierra Club North Star Chapter, and others, that the Applicants had not demonstrated that the La Crosse Project was needed to provide reliable service to Rochester and La Crosse.[322] Some were concerned that the La Crosse Project would encourage transport of coal generation from the Dakotas to points east of Minnesota.[323]

276. With few exceptions, compliance with the conservation statute would result in energy savings significantly higher than the levels electric utilities have achieved in the past. This is reflected in the OES analysis. The conservation statute sets an aggressive but achievable goal.[324] Although it may be possible to achieve higher levels of conservation, there are no solid estimates upon which to base a lower forecast.[325] Also, in evaluating conservation savings greater than 1.5 percent, the additional costs to attain the higher level must be considered.[326]

277. The Applicants' consideration of conservation and load management is reflected in their estimates of future load growth and is validated by the OES analysis. Mr. Davis calculated the impact of the conservation statute on demand as a whole and on five local load areas included in the Application and concluded that forecasted load would exceed the critical load level by 2011 in four of the areas, Rochester, La Crosse, Red River Valley and St. Cloud, taking into account the 1.5 percent energy savings goal. With the 1.5 percent energy savings goal, the Alexandria load forecast would exceed the critical load level between 2015 and 2017.[327]

278. Even if load growth is smaller than forecasted, the Renewable Energy Standard will bring new generation into the system that would require additional

---

[318] *See e.g.*, Pub. Comm. Pfenning, filed 10/06/08, #5551876; Wambeke, Christenson, filed 9/23/08, #5551877; Francois, Hunt, filed 9/22/08, #5518689; Falc, Bovee, filed 9/22/08, #5518690.
[319] Pub. T., Tab 15, Halley (Cannon Falls); Pub. Ex. 29.
[320] Pub. Comm., Radcliffe, filed 8/25/08, #5464474; van Schaik, Bot, Lundberg, filed 10/06/08, #5551881; Quinlivan, filed 7/31/08, # 5405095; Sigler, filed 9/24/08, #5520590.
[321] *See e.g.,* Pub. Comm., Wilson, filed 7/31/08, #5405084.
[322] Pub. Comm., Levin, filed 10/07/08, #5554862; Pub. T., Tab 17, Eide-Tollefson (Winona).
[323] *See e.g.,* Pub. T., Tab 18, Erickson (Rochester).
[324] Ex. 215 at 2 (Davis Direct).
[325] Ex. 215 at 3 (Davis Direct).
[326] T. 21 at 89-90 (Davis).
[327] Ex. 215 at 15-16 (Davis Direct).

transmission.[328] Compare the 3,160 to 4,927 MW needed for RES to the 1,370 MW of estimated conservation at 1.5 percent.[329]

279. No party calculated conservation estimates that yielded forecasts lower than the identified critical load levels.

280. Overall, although achieving the energy conservation goals will reduce load levels, the offset is not sufficient to meet projected regional load growth, the community needs identified by the Applicants, or to increase generation outlet.[330]

281. There is no evidence that CapX projects will impede the development of distributed generation. Xcel Energy currently has plans to buy 500 MW of C-BED and has PPAs for 200 MW or more. Adding C-BED projects will not reduce the need for transmission to import energy when wind power is not available.[331]

282. The public's interest in conservation, demand management, and renewable energy is reflected in the legislatively enacted conservation and renewable energy standards, the impetus for C-BED, and the DRG and RES studies. The CapX projects are consistent with the current laws. There is no basis to hold the Applicants to higher, undefined standards in this proceeding.

A (3). Effects of the Applicants' Promotional Practices.

283. There was no evidence that the Applicants engaged in promotional practices that have increased the use of or demand for electricity. The Applicants have publicized the need for additional transmission capacity in Minnesota to maintain and improve the system. [332]

284. OES has reviewed the promotional practices of the Applicants in several cases since 2006 and concluded that this criterion had been met.[333]

A (4). Ability of Facilities that Do Not Require Certificates of Need to Meet the Future Demand.

285. Alternatives not requiring a certificate of need could be either generation facilities or transmission facilities.[334] The Applicants analyzed transmission and generation alternatives that do not require a certificate of need. In general, upgrading existing facilities and reconductoring alone could not meet the projected increase in load to 2020. For the Fargo project, some improvements decreased voltage to unacceptable

[328] T. 1A at 92-93 (Rogelstad).
[329] Ex. 247 at 4 (Peirce Surrebuttal), Ex. 215 at 12 (Davis Direct).
[330] *See,* Ex. 215 at 17 (Davis Direct).
[331] Ex. 1 at 7.18-7.20 (Application); Ex. 9 at 5 (Rogelstad Rebuttal).
[332] Ex. 1 at 1.20-1.21 (Application).
[333] Ex. 282 at 84-85 (Rakow Direct).
[334] *See* Minn. Stat. §§ 216B.169, 216B.2421, subd. 2.

levels. For the Brookings Project, additional rebuilding and reconductoring could not significantly increase generation outlet.[335]

286. OES concurred that the scope of the needs addressed by the CapX project, including community service reliability, regional reliability, and creation of additional generation outlet, could not be met by non-certificate-of-need alternatives.[336]

287. NoCapX and CETF contended that the Applicants did not properly consider existing local generation in the analysis of community need. However, both the Applicants and MISO evaluated the ability of local generation to serve load and the reliability of the system when the generators were not available.[337]

288. The No Build Alternative would provide none of the benefits associated with the CapX projects.[338] None of the parties offered an alternative that could improve regional reliability, meet the identified community needs, or improve renewable generation outlet capacity.

A (5). The Effect of the Proposed Facility, or a Suitable Modification, to Use Resources Efficiently.

289. The CapX projects will use resources efficiently.

290. The Applicants have shown that the probable result of denial of the certificates of need would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicants, to the applicants' customers, or to the people of Minnesota and neighboring states. They have demonstrated that load growth will rise to 24,701 MW or more by 2020, that the capacity to serve five local areas will be exceeded prior to 2020, and that there is a need to support additional generation outlet.

291. Rule 7849.0120 B: requires that a certificate of need be granted to the applicant if:

B. A More Reasonable and Prudent Alternative to the Proposed Facility Has Not Been Demonstrated by a Preponderance of the Evidence on the Record, Considering:

B (1). The Appropriateness of the Size, Type and Timing of the Proposed Facility, Relative to Reasonable Alternatives.

---

[335] Ex. 1 at 7.24-7.25 (Application); Ex. 9 at 3-5 (Rogelstad Rebuttal).
[336] Ex. 282 at 28-30 (Rakow Direct); OES Reply Brief at 35-36.
[337] Rochester: Ex. 94 at 6-7 (King Direct); Ex. 56 at 27 (Webb Direct); La Crosse: Ex. 94 at 9-11 (King Direct); Ex. 56 at 29-31 (Webb Direct); So. Red River Valley: Ex. 67 at 6 (Kline Direct); Ex. 56 at 18 (Webb Direct); Alexandria: Ex. 67 at 8 (Kline Direct); Ex. 56 at 23 (Webb Direct); St. Cloud: Ex. 67 at 11 (Kline Direct); Ex. 56 at 25-26 (Webb Direct).
[338] Ex. 1 at 7.36-7.40 (Application); Ex. 67 at 18-19 (Kline Direct).

292. The "size" of the project refers to the quantity of power transfers that the transmission infrastructure improvement enables. The CapX projects are designed to address the level of need identified in A (1): to support system-wide load growth, meet projected load growth in specified local areas, and increase generation outlet. Two alternatives were sufficiently developed to address the demonstrated level of need: the CapX projects as proposed, and the Upsized Alternative.

293. Applicants have demonstrated that the CapX projects are needed to meet its identified needs.

294. Applicants also provided the information necessary to consider whether the Upsized Alternative is a more reasonable and prudent alternative.[339]

295. Other parties must show that there is a more reasonable and prudent alternative to the Applicants' proposal.

296. Although there is evidence that some of the local needs identified in the Application may be met with generation and lower voltage transmission, no specific alternative was proposed to meet those needs, nor was an alternative offered that would address regional reliability and supply the same level of generation outlet. In some instances, the parties who contested the need for the proposed projects relied upon generation or transmission facilities that would require certificates of need that have not yet been approved or for which no applications have been filed.

297. OES closely evaluated the costs of the three projects, including the cost of energy losses[340] and termination points,[341] to determine if there was a more reasonable and prudent alternative to the CapX projects.

298. OES concluded that Applicants' proposed size for the La Crosse Project and the Fargo Project was reasonable to meet community service reliability.[342] Although the Applicants were not able to quantify the size of the community service reliability needs served by the Brookings Project, OES concurred that the Brookings Project would have some avoided cost benefits.[343]

299. OES initially took the position that the CapX projects may be too small to meet the forecasted load growth and provide sufficient outlet for high quality renewable resources.[344] Since both the Fargo Project and Brookings Project provide access to high quality renewable resources, OES asserted that higher voltage alternative should be considered. Because the study, design, permitting and construction of transmission lines extend over many years, a proposed project should take into account needs into

---

[339] *See* Minn. R. 7849.0110.
[340] Ex. 282 at 40-55 (Rakow Direct).
[341] Ex. 282 at 57-68 (Rakow Direct).
[342] Ex. 282 at 16, 17 (Rakow Direct).
[343] Ex. 282 at 18-20 (Rakow Direct).
[344] Ex. 282 at 18,32-33 (Rakow Direct).

the foreseeable future.[345] OES also questioned whether the Applicants had understated the total costs of a higher voltage line, including line losses, and posited that higher voltage may be more cost-effective.[346]

300. Electrical line losses are one measure of efficiency. If there is significant line loss, additional electricity must be generated, and the higher the loss, the greater the cost of extra generation. Line losses are a significant factor in evaluating the overall cost of each option.[347]

301. Based on information provided by the Applicants on the cost of constructing the Twin Cities to Fargo line at 500 kV (Fargo 500kV Alternative), and calculation of line losses, OES concluded that under three out of four potential scenarios a Fargo 500 kV Alternative would be the least cost choice. Under only one scenario, no increased use of the proposed line above the level assumed by Applicants, would the Applicants' proposed Fargo Project be the least cost choice, with significant energy savings.[348]

302. MCEA witness Schedin also questioned whether the Fargo Project was too small as proposed to serve the Project's stated need. Mr. Schedin recommended that the Applicants consider a 345 kV double-circuit alternative.[349]

Development of the Upsized Alternative

303. In response to the direct testimony of OES and MCEA, the Applicants re-examined all of the projects to determine whether they should be upsized and compared the optimal electrical performance, the costs and other characteristics associated with the identified options. Applicants analyzed six alternatives, including the single-circuit 500 kV option proposed by Dr. Rakow and the double circuit 345 kV option proposed by Mr. Schedin:

a. 345 kV single-circuit with larger conductors;

b. 345 kV double-circuit with both circuits deployed immediate;

c. 345 single-circuit installed, double circuit capable;

d. 500 kV single-circuit;

e. 500 kV double-circuit; and

f. 345 kV and 500 kV double-circuit using common structures.[350]

[345] Ex. 282 at 33-37 (Rakow Direct). For this project, the studies began before 2005 and the in-service date of the projects extends to 2015. *See,* Ex. 282 at 37 (Rakow Direct).
[346] Ex. 282 at 33, 74-75 (Rakow Direct).
[347] Ex. 282 at 43-53 (Rakow Direct)
[348] Ex. 282 at 74, 75-77 (Rakow Direct).
[349] Ex. 177 at 23 (Schedin Direct).

304. In their review, Applicants applied a number of factors, including an estimate of future growth, ability to serve load and provide bulk power, flexibility, cost including losses, thermal limits, physical characteristics and so forth. Although the Applicants did not conduct new engineering studies, the upsized models were analyzed and check against obvious benefits and detriments.[351]

305. The Applicants analyzed the single-circuit 500 kV option, including Dr. Rakow's analysis of line loss. Dr. Rakow's analysis is premised on an increase of transfer across the NDEX for the proposed Fargo line that would require other upgrades to the underlying transmission system. Those upgrades have not been studied or built into the model. Adding additional capacity would be limited by the ability of the underlying system to withstand the new line's outage. Because the increase in transfer capability would require installation of another high voltage line, the benefits may not be achieved for several years.

306. The 500 kV line has fewer load serving benefits and provides less ability for interconnection. Since a fully-utilized double-circuit 345 kV line provides similar capability as a 500 kV line, the Applicants preferred the configuration that would best address multiple issues.[352] A double-circuit 345 kV line will also require less right-of-way than a single-circuit 500 kV line would require.[353]

307. Although a double-circuit 345 kV line may have higher line losses than 500 kV facilities, the cost of the line losses is outweighed by the difficulties of integrating 500 kV facilities into the underlying system. Applicants agreed with Mr. Schedin that a double-circuit 345 kV option was preferable.[354]

308. The Applicants concluded that the three projects as proposed were adequate to meet the load-serving and immediate generation outlet needs outlined in the Application, but that taking the longer view, a double-circuit 345 kV configuration, the Upsized Alternative, would provide a better solution. Because the benefits of the second circuit cannot be realized until other transmission projects occur, the Applicants do not recommend adding the second circuit at this time. Instead, Applicants propose constructing towers that will allow the second circuit to be strung when needed.[355]

309. Applicants also prefer the double-circuit 345 kV option over the 500 kV option because Minnesota utilities have more experience with 345 kV, and no experience using 500 kV for load-serving purposes.[356]

310. OES evaluated three alternatives to upsize the proposed Fargo Project:

---

[350] Ex. 121 at 15, 32-34 (Grivna Rebuttal).
[351] Ex. 121 at 14-15 (Grivna Rebuttal).
[352] Ex. 121 at 19-25 (Grivna Rebuttal).
[353] Ex. 121 at 26 (Grivna Rebuttal).
[354] Ex. 121 at 27-30, 32 (Grivna Rebuttal).
[355] Ex. 121 at 9-10 (Grivna Rebuttal); Attachments A-D.
[356] Ex. 121 at 34 (Grivna Rebuttal).

a. 345 kV double-circuit capable, single-circuit installed (Upsized Alternative);

b. 345 kV double-circuit; and

c. 500 kV single-circuit.

311. Dr. Rakow concluded that either the 345 kV double-circuit or the 500 kV single circuit was economically superior to the Applicants' proposed project or the Upsized Alternative because of their energy conservation benefits.[357] He reviewed the Applicants' engineering analysis of the alternatives, including Applicants' witness Grivna's evaluation of the 500 kV alternative. Most of Mr. Grivna's concerns, although shared in part by Mr. Schedin and Mr. Webb, were not significant to Dr. Rakow.[358]

312. Dr. Rakow agreed that the Applicants' concern about the stability of adding a 500 kV alternative was significant.[359] Moving to 500 kV and the higher transfer levels could result in unanticipated impacts on regional stability that would have to be mitigated to obtain maximum transfer capability.[360]

313. In comparison, by installing a single-circuit 345 kV line initially and conducting additional studies, one could be certain that adding a second circuit would not decrease the system's stability and would maximize the line's potential.[361]

314. Due to the lack of stability analysis, Dr. Rakow concluded that no option was superior to the Applicants' Upsized Alternative.[362] Mr. Schedin concurred that there was no more reasonable and prudent alternative.[363]

315. The Applicants acknowledge that additional certificates of need will be required before the second circuits are added. New studies must be conducted to determine the underlying upgrades that would be required with the addition of the second circuit. The capacity and thermal ratings of the second circuits will be evaluated at that time.[364]

316. CETF claimed that "the performance of the upsizing option has not been verified with load flow study or by other means." However, the Upsized Alternative does not change the conductors, transformers, voltages, number of circuits strung, or other parameters used in the original engineering analysis. Rather, the proposal is to build larger towers to allow stringing a second circuit at a later date. Construction of the

[357] Ex. 307 at 16 (Rakow Surrebuttal).
[358] Ex. 307 at 16-19 (Rakow Surrebuttal).
[359] Ex. 307 at 19 (Rakow Surrebuttal).
[360] Ex. 121 at 24 (Grivna Rebuttal)
[361] Ex. 121 at 24 (Grivna Rebuttal).
[362] Ex. 307 at 20, 21 (Rakow Surrebuttal); Ex. 308 at 5 (Rakow Statement).
[363] Ex. 199 at 5 (Schedin Surrebuttal).
[364] Ex. 121 at 35 (Grivna Rebuttal); *see also* NoCapX Posthearing Brief at 1.

second circuit would require a certificate of need and the appropriate engineering studies.[365]

317. The additional cost of the Upsized Alternative is about $200 million, significantly more expensive than the three proposed projects. The extra costs are attributed to building larger, stronger structures to which a second circuit can be added at a later date. The higher costs will be built into the rates paid for transmission service. The Applicants acknowledge that stringing the second circuit for any of the projects will require another certificate of need, and they have made no showing that the need is present. Thus, the decision whether to incur approximately $200 million must be based on whether it is prudent to invest now because additional lines may be needed at some time in the future and the configuration of these projects will serve that need.

318. The Applicants, OES, MISO and MCEA believe that the Upsized Alternative presents a cost-effective opportunity to serve future needs and to minimize the difficulty of siting and constructing future large transmission lines. In some parts of the country it is standard practice to install large structures to facilitate later double-circuiting.[366]

319. There are no specific load-growth forecasts to support the Upsized Alternative for either regional reliability or to improve community service.

320. For the Fargo Project, the estimated incremental cost of the Upsized Alternative is $80 to $110 million.[367] Dr. Rakow and Mr. Schedin demonstrated that the area west of the Fargo Project is rich with resources and currently constrained. An increase of transfer capability to the 1200 MW level that was used to study a higher voltage option will require a certificate of need to upgrade the Minnesota Valley–Blue Lake 230 kV line to 345 kV double-circuit, at an estimated cost of $410 million, and additional costs of approximately $125 to $250 million to upgrade underlying facilities.[368]

321. The Minnesota Valley-Blue Lake 230 kV line presents a significant constraint on further expansion of both the Fargo Project and the Brookings Project. Studies are underway to upgrade the line to 345 kV single or double circuit. Applicants anticipated that an application for a certificate of need would be filed in 2009.[369]

322. For the Brookings Project, the incremental cost of the Upsized Alternative is $51 to $55 million.[370] The large number of interconnection requests on the MISO queue, and the high quality of wind resources in western Minnesota and eastern South Dakota are strong evidence that a second circuit will be needed. The total number of forecasted megawatts needed to meet RES also supports this probability. Also, the Brookings Project as proposed included some double-circuit segments. Adding larger

[365] Ex. 121 at 10 (Grivna Rebuttal); OES Reply Brief at 52.
[366] T. 5B at 52-53 (Webb).
[367] Ex. 88 at 4 (Stevenson Rebuttal); Attachment F.
[368] Ex. 88 at 6 (Stevenson Rebuttal).
[369] Ex. 70 at 10 (Kline Rebuttal); Ex. 104 at 13-14 (Alholinna Direct).
[370] Ex. 120 at 4-5 (Lennon Rebuttal); Attachment F.

structures to allow expansion for a second circuit may help address transmission development that is already under consideration. The Helena-Lake Marion-Hampton Corner segment could become a part of a possible second 345 kV loop around the outside of the current metropolitan area.[371] It is anticipated that the addition of the Minnesota Valley-Blue Lake upgrade to 345 kV could increase the generation outlet capacity of the Brookings Project from 1900 MW to 3000 MW.[372]

323. For the La Crosse Project, the costs of the Upsized Alternative will depend on the choice of river crossing. For the Alma Crossing, the incremental costs are approximately $25 to $41 million. For the Southern Crossing, the incremental costs are approximately $52 to $69 million.[373]

324. As proposed, without upsizing, the La Crosse Project will meet the projected need for several decades. With upsizing, a second 345 kV circuit could provide Minnesota with access to potentially more economical power generated to the south or east. It could also increase delivery options during high wind, low load periods, and increase import capability load is high and the wind is not blowing. If states to the east add or expand renewable energy requirements, a second circuit could increase the potential to deliver some of the high quality wind resources from the west to the east.[374] Only these general statements support the Upsized Alternative. There are no specific proposals or contingencies that were identified that would suggest that the Upsized Alternative is a more reasonable and prudent alternative to the La Crosse Project as proposed.

325. The La Crosse Project as proposed with the RIGO lines will substantially increase generation outlet for renewable energy.

326. Although it is difficult to quantify the benefit, the Upsized Alternative may prevent the disruption of environmentally sensitive areas for an additional Mississippi River crossing. Since the need for a second circuit may be decades away, it is difficult to predict what other changes may occur or technologies may be in place that would eliminate the need for such a crossing at that time.

327. There is no evidence in the record to determine whether it would be a reasonable and prudent alternative to limit the Upsized Alternative to installation of the larger, double-circuit compatible structures only in the environmentally sensitive areas on the two sides of the Mississippi River crossings.

328. In summary, the Applicants have demonstrated that the Upsized Alternative is a more reasonable and prudent alternative for the Fargo Project and the Brookings Project to address current constraints on the system and significantly increase generation outlet capacity. Applicants have failed to demonstrate that the

[371] Ex. 121 at 36-39 (Grivna Rebuttal).
[372] Ex. 104 at 14 (Alholinna Direct).
[373] Ex. 89 at 4 (Stevenson Rebuttal); Attachment F.
[374] Ex. 121 at 40-41 (Grivna Rebuttal).

Upsized Alternative is a more reasonable and prudent alternative to the La Crosse Project as proposed.

Selection of Conductor

329. NoCapX challenged the MVA capacity of the capacitors selected by the Applicants, claiming that only a small portion of the rated capacity would be used.[375] NoCapX's representative may be confused about the increased outlet capacity provided by the transmission line and the thermal capacity of that line. However, as pointed out by Mr. Alholinna, the MVA capacity is selected to support the operation of the transmission system as a whole. [376]

330. In selecting the appropriate cable, the Applicants balanced the costs to acquire the cable versus the benefits resulting from the cable's performance. The bundled conductor 954 ACSS cable was selected for its characteristics of lower losses with slightly higher cost at higher loadings. OES concluded that the sizes of the proposed conductor were reasonable, and no alternative was offered.[377]

Installation of Direct Current (DC) Lines

331. The Applicants considered the alternative of installing direct current (DC) lines, and related substations. However, the alternative was rejected because of the high estimated cost: $9.7 billion for the DC configuration, compared to approximately $1.5 million for the CapX projects as proposed.[378] OES reviewed this analysis and concurred that the DC option was not viable.[379] No other party offered expert testimony addressing Applicants' proposed AC line.

NAWO/ILSR Has Failed to Provide an Alternative to the CapX Projects

332. NAWO/ILSR asserted that each element of need can be met with a more reasonable and prudent alternative with far less harm to the natural and socioeconomic environments and with the same level of reliability. CETF endorsed NAWO/ILSR's position.[380] However, they have failed to produce sufficient information to evaluate any alternative to the Applicants' proposals.

333. NAWO/ILSR relied in part on conservation measures such as Smart Grid and demand management, but, as addressed above, NAWO/ILSR failed to produce substantiated forecasts to support its claims. There is no evidence that conservation and demand management can meet the projected load growth for the region or for the identified communities.

[375] NoCapX Brief at 2, 10-11.
[376] T. 10 at 117-119 (Question from Overland; Alholinna Response).
[377] Ex. 282 at 21-22 (Rakow Direct).
[378] Ex. 1 at 7.25-7.26 (Application).
[379] Ex. 282 at 23 (Rakow Direct).
[380] NAWO/ILSR Posthearing Brief at 26-27; CETF Posthearing Brief at 4-5.

334. Also, NAWO/ISLR contended that the Applicants failed to demonstrate that the Brookings Project was the least cost option or necessary to comply with the RES. However, it failed to offer an alternative that could add the equivalent of 700 MW of renewable energy to the transmission system or the costs and upgrades for such an alternative.

335. NAWO/ILSR favored dispersed generation technologies over large, remote central-station power plants, connected to load centers with relatively few high voltage lines, because dispersed generation is "cost-competitive and often cheaper and faster to implement than central station based strategies."[381] It asserted that large central-station power plants will not be built in the future and that dispersed, small generation, closer to load is the new paradigm and a more cost-effective alternative.

336. Many members of the public also supported increased C-BED, both because of its benefits to local communities and because they perceived that C-BED could serve local load and minimize the need for new transmission. Some were concerned that the CapX projects' large size would inhibit C-BED.[382]

337. No party, including NAWO/ILSR, came forward with a specific proposal to site small generation facilities, with approximate locations, the associated costs, engineering studies and transmission upgrades, as an alternative to the CapX project as a whole, or for the La Crosse, Fargo, or Brookings Projects individually. Instead, NAWO/ILSR relied on the results of the DRG Study[383] to support its claim. No party has shown that the DRG Study results offer a viable alternative to the CapX projects.

338. Phase I of the DRG Study was conducted to determine if 600 MW of dispersed renewable generation of 10 to 40 MW each could be sited with minimal impact on the regional transmission system. The DRG Study was conducted at the direction of the Legislature as part of the Next Generation Energy Act of 2007. A Technical Review Committee (TRC) oversaw each step of the study and reviewed its progress and results. A smaller study team conducted the analysis under the direction of the TRC. The study team developed a state-wide model of the electrical system that included lower voltage lines and developed a methodology for identifying potential opportunities for dispersed renewable generation. The study results demonstrated that 600 MW could be sited without significantly affecting any transmission infrastructure, but that even dispersed generation could have a substantial impact on the transmission grid overall.[384]

---

[381] NAWO/ILSR Brief at 1-2.
[382] Pub. T., Tab 3, Fuchs (Melrose); Tab 7, Dacey (Marshall); Tab 11, Magnussen (New Prague); Tab 12, Budenski (Lakeville); Tab 13, Olstad, Diffley (Lakeville); Tab 14, Tyler (Cannon Fall); Tab 15, Beckman, Longfellow, Topp (Cannon Falls); Pub. Comm., Grecco, Kawahara, Ouray filed 7/31/08, #5405095; Peter Dwyer, Avon Hills Initiative, filed 7/08/08, #5322765.
[383] Ex. 110, "Dispersed Renewable Generation Transmission Study," Volumes 1-3, prepared by Minnesota Transmission Owners, June 16, 2008, Docket No. E999/DI-08-649.
[384] Ex. 110 at 3.

339. After applying several screening criteria, 300 potential DRG locations were selected and then narrowed to 42 geographically diverse sites for closer examination. As part its analysis, the study team attempted to distribute the DRG across the five out-state planning zones. The study team was not able to locate any potential connection zones in the Northwest Planning Zone, and for 19 of the 42 sites, there were transmission limitations below 40 MW.

340. The conclusions were limited in that the ability of any one project to actually connect at the identified site would require detailed assessment and coordination with MISO. Pending interconnection requests may occupy potential interconnection sites.[385]

341. The DRG Study showed that even small amounts of DRG added to the lower voltage system in the Northwest, Northeast, and West Central planning zones could overload the system and impact the high voltage system for three hundred miles or more.[386] The constraints limited all types of renewable generation, both dispersed and larger scale.[387]

342. The Fargo Project and Brookings Project will pass through the areas where the DRG Study identified the fewest opportunities for siting.[388]

343. One of the parameters of the DRG Study was that it looked at interconnection opportunities in 2010, before any of the CapX projects would come on line.[389] It is also significant that the DRG Study was a "gen-to-gen" study. That is, to evaluate whether DRG could be added, 600 MW of other generation was taken off line. The DRG Study did not attempt to determine if that 600 MW could be added back into the system. A MISO interconnection study would take into account existing generation.[390]

344. There was no evidence that the DRG locations identified in the study could improve the regional reliability of the transmission system or meet the community needs identified in the Application, even if each one were successfully sited.[391] Since the projected quantity of generation to meet the RES is between 3,160 MW and 4,927 MW,[392] there is no basis to conclude that approval of CapX will impede siting 600 MW of DRG.

345. Mr. Schedin, also a member of the TRC, gave several specific reasons why the DRG Study did not demonstrate that dispersed generation was a substitute in

---

[385] Ex. 110 at 13-14.
[386] Ex. 109 at 5 (Alholinna Surrebuttal). Mr. Alholinna was the Study's Team Lead and member of the TRC.
[387] Ex. 176 at 2-3 (Gramlich Surrebuttal).
[388] *Compare,* Ex. 110 at 49 (Final DRG Site Map), *with* Ex. 1 at 2.5, Fig. 2-2, and 2.6-2.8, Fig. 2-3 (Application).
[389] T. 9 at 183 (Alholinna).
[390] T. 10 at 88-91 (Alholinna).
[391] T. 11 at 70, 75 (Alholinna).
[392] Ex. 275 at 1 (Ham Surrebuttal); Ex. 247 at 4 (Peirce Surrebuttal).

whole or in part for the CapX projects. The DRG Study examined a snapshot of transmission in 2010 while the CapX projects address needs identified in 2014 and beyond; the Study showed that new dispersed generation in the West-Central planning zone required major transmission additions; the Study did not take into account projects already in the MISO queue that may be built before 2010; the Study expressly stated that actual siting of the identified dispersed generation projects would require additional study; and transformers supplying the Dorsey-Forbes 500 kV line create a bottleneck to good wind sites with the possible exception of southeastern Minnesota.[393]

346. Based on his participation in the DRG Study, Mr. Schedin's opinion was that any dispersed generation would have some impact on the transmission system unless equivalent generation at the same site was shut down. Restricting wind development to areas with the least transmission impact may not take advantage of superior wind sources.[394]

347. It is a fundamental policy of Minnesota energy planning to use existing transmission infrastructure more efficiently through installation of dispersed renewable generation and also to significantly increase high-voltage transmission capacity in the state.[395] The DRG Study focused on the ability to install dispersed renewable generation into the existing transmission system, but also demonstrated the need for increased high-voltage transmission.

348. NAWO/ILSR contended that the Applicants have perpetuated an outdated paradigm by injecting large amounts of generation into its models and that CapX may foster the development of large transmission and impede small, dispersed generation.[396]

349. Under some circumstances, reliable generation and strategic lower voltage enhancements may displace the need for some higher voltage transmission.[397] However, NAWO/ILSR failed to show that addition of several small generators would be more cost-effective than a large generation plant. The Applicants estimated that a 168 MW combustion turbine would cost at $541 per kW while a smaller 29 MW combustion turbine would cost about $1,416 per kW.[398] Without closer examination of the specific facility, its use, and the transmission improvements it would require, it is not possible to conclude that siting small generation would be more cost-effective than the Applicants' proposal. Mr. Alholinna, the Team Lead for the DRG Study, stated that the study did not demonstrate that "finding sites with smaller amounts of generation outlet has an

[393] Ex. 199 at 15 (Schedin Surrebuttal).
[394] Ex. 195 at 10-11 (Schedin Rebuttal); Ex. 199 at 16 (Schedin Surrebuttal).
[395] Ex. 110 at 3.
[396] Ex. 140 at 16-17, 35-36 (Michaud Direct).
[397] T. 6 at 119 (Kline).
[398] Ex. 1 at 7.14 (Application).

advantage over large generation plants." [399] Specifically, Mr. Alholinna did not believe that the DRG Study findings affected the need for the CapX projects.[400]

350. NAWO/ILSR incorrectly argued that the burden is on the Applicants to produce a model that added dispersed generation, and to conduct the appropriate power flow analysis up to the level that the system reliability, local load serving benefits, and renewable generation support were comparable to CapX. In its view, the Applicants are required to run that model to meet their burden of proof, and their failure to do so restricts the ability to compare that alternative.[401]

351. NAWO/ILSR overstated the utilities' obligation to analyze alternatives. The certificate of need statute requires Applicants to consider whether distributed generation, among other options, is an alternative to meet energy demand.[402] In developing each CapX project, the Applicants looked at a variety of alternatives, including siting local generation. They concluded that those alternatives were not cost effective or failed to provide the same overall benefits to the transmission system as the CapX projects. OES also considered dispersed generation as an alternative but concluded that it could not address the scope of the needs addressed by CapX.[403] The Applicants were not required to conduct the specific analysis NAWO/ILSR and NoCapX requested.

352. Similarly, NoCapX contended that dispersed wind generation can be sited locally to meet the RES without transmission. It contended that the Applicants did not consider taking existing generation off-line to make room for renewable generation.[404] NoCapX failed to explain how replacing one form of generation with another would increase regional reliability or address identified community needs.

353. Several studies were underway at the time of the hearing in this proceeding that may provide the type of information that will allow for the analysis that NAWO/ILSR, CETF and NoCapX advocates, but at this time, results are incomplete and no reasonable alternative has been proposed to provide the generation outlet capability that the Brookings Project can provide.

354. Since it takes many years to plan and build transmission lines, states have attempted to construct new lines into areas with high wind resources, thereby increasing the likelihood that renewable generation will connect to the planned lines and that renewable energy standards will be met.[405] The DRG Study does not support NAWO/ILSR's contention that developing smaller sized, dispersed wind generators closer to load will change the type of transmission facilities needed.[406] Rather, the DRG

[399] T. 11 at 69 (Alholinna).
[400] T. 11 at 70 (Alholinna).
[401] NAWO/ILSR Posthearing Brief at 11-12.
[402] Minn. Stat. § 216B.243, subd. 3 (6); NAWO/ILSR Posthearing Brief at 9.
[403] Ex. 282 at 28-29 (Rakow Direct).
[404] NoCapX Posthearing Brief at 17.
[405] Ex. 175 at 6-7 (Gramlich Rebuttal).
[406] Ex. 148 at 18 (Michaud Rebuttal).

Study concluded that small injections of dispersed generation tend to flow on the high-voltage grid in the same manner as larger scale generation.[407]

355. The DRG Study supports the Applicants' contention that existing constraints on the high-voltage system limit the potential for all types of new renewable generation, both dispersed and larger-scale.[408]

356. NAWO/ILSR asserted that the total cost of delivered energy, both the cost of generation and transmission, is the appropriate basis for analysis of alternatives.[409] CETF witness Kildegaard concurred with NAWO/ILSR that evaluation of the CapX projects required analysis of the cost of the transmission and the cost of the related generation expansion.[410]

357. Others disagreed that it was reasonable to attempt to analyze the precise impact that transmission will have on future generation.[411]

358. The Commission has two distinct planning processes. The IRP establishes each utility's plans to expand generation, including both supply-side and demand-side growth. Biennial transmission planning is a different process, undertaken jointly by the utilities to evaluate the need for new transmission to meet projected growth.[412] Although in theory, planning generation and transmission together is reasonable, the elements are continually changing and the range of options is unlimited. Practicality dictates that the two processes are separate, but that each process is informed by the other.[413]

359. In summary, NAWO/ILSR failed to propose a more reasonable and prudent alternative to the CapX projects.

B (2). The Cost of the Proposed Facility and the Energy Supplied by It, Relative to Reasonable Alternatives.

360. The capital costs for the Proposed Projects and the Upsized Alternative are summarized in Attachment F, attached to this Report.[414]

361. As part of each of the underlying studies that led to the Application, the Applicants evaluated several options, including the costs associated with them. No party questioned the specific costs included in the calculations. The analysis of line losses was included in evaluation of the higher-voltage alternatives.

---

[407] Ex. 110 at 12; *see also,* Ex. 176 at 2-3 (Gramlich Surrebuttal).
[408] *See also,* Ex. 176 at 2-3 (Gramlich Surrebuttal).
[409] Ex. 140 at 44 (Michaud Direct).
[410] Ex. 161 at 4 (Kildegaard Direct).
[411] Ex. 175 at 9 (Gramlich Rebuttal).
[412] Ex. 303 at 17-18 (Rakow Rebuttal).
[413] *Accord,* Ex. 303 at 19-20 (Rakow).
[414] Cost estimates are stated in 2007 dollars. Ex. 1 at 2.17 (Application).

Cost to Minnesota Customers

362. It is difficult to estimate the cost of the CapX project to Minnesota customers. Once the projects are on line, MISO allocates the costs for transmission based on a formula which takes into account the purpose of the line and the portions of the MISO footprint that will benefit from the improved reliability that the new lines add to the system. Whether MISO classifies the proposed projects as a Baseline Reliability project or a Generator Interconnection Network Upgrade will affect the cost allocation.[415] The Applicants expect that the Fargo Project and Brookings Project and 80 percent of the La Crosse Project will be subject to the MISO formula. The Applicants estimated the projects' revenue requirements and allocated the costs to the MISO pricing zones. Then, it estimated the charges to the CapX owners, based on projected ownership shares. Its analysis was premised on MISO classifying each of the three CapX projects as Baseline Reliability projects.[416]

363. OES developed a rough estimate of the impact of the increased cost of the CapX projects to Minnesota customers. Based on those estimates, a residential customer using 800 kWh of electricity per month would see an increase ranging from approximately 40 cents per month for a Minnesota Power customer to a $2.15 per month for an Xcel Energy customer (with a very small decrease for Wisconsin Public Power customers). The estimate took into account the benefit of lower line losses but did not include the costs or savings of the Upsized Alternative.[417]

364. The actual costs will depend in part on the ultimate distribution of ownership among the participating utilities. The OES estimates are based on the Applicants' preliminary ownership structure, but the total project cost could vary between $0.88 billion (low costs, all public power ownership), and $1.77 billion (high costs, all investor owned).[418]

365. NAWO/ILSR hypothesized that Minnesota ratepayers may be double-billed for the Brookings line, once by MISO for allocation of the cost of the lines to serve load, and also for the portion of the costs borne by generators to connect and deliver energy to Minnesota consumers.[419] There are components to the rates customers pay for electricity, including a portion for transmission and a portion for the cost of the energy, including generation. Thus, to the extent that the CapX lines provide transmission that serves Minnesota customers, the customers will pay some of the cost. If new generation is added that also serves Minnesota customers, the cost of generation may include the generator's costs to connect to the transmission system, but that is not the same as the cost of transmission itself.

366. Some members of the public expressed concern that long transmission lines will have costly, high line losses. In their view, such losses are wasteful and can

---

[415] Ex. 2 at D-5 (Application); T. 5B at 69 -71 (Webb).
[416] Ex. 2 at D-5 (Application): Ex. 137 at 2-3 (Grover Direct).
[417] Ex. 310; T. 24 at 122-124; T. 25 at 41-42, 47-49 (Rakow).
[418] Ex. 282 at 70 (Rakow Direct).
[419] NAWO/ILSR Brief at 36.

be reduced by siting generation closer to load.[420] Dr. Rakow closely analyzed the line losses of several options and concluded that the CapX projects would in fact reduce line losses.[421]

367. By connecting into the 345 kV networks that serve the Twin Cities, the combined projects will improve access to existing and future resources within the MISO market. This can be expected to lower on average marginal energy prices in the near term and in the long term ensure adequate energy supplies to the Twin Cities and surrounding area.[422]

368. MISO supported the CapX projects in part because of the economic benefit the transmission lines will provide. By extending in different directions, the new lines will give utilities access to the most cost-effective generation available across a broad geographic area.[423]

B (3). The Effects of the Proposed Facility Upon the Natural and Socioeconomic Environments Compared to the Effects of Reasonable Alternatives.

Effect on the Land and Its Inhabitants

369. The Application contains a general discussion of the natural features along the corridors of each proposed transmission line and detailed maps of each route segment.[424] Each project corridor includes managed and regulated land, including municipal and county parks and trails, trust lands, state trails, trout streams and other public waters, federal easement lands, forest lands, Wildlife Management Areas, Waterfowl Protection Areas, state parks, National Wildlife Refuges and Scientific and Natural Areas. All three projects involve crossing at least one major waterway, and there are airports in each project area.

370. The public raised concerns that the construction of a transmission line will decrease the value of the property it crosses or borders.[425] The ER references a Wisconsin Public Service Commission analysis that made six general observations that OES apparently accepts:

a. The potential reduction in sale price for single family homes may range from 0 to 14 percent.

b. Adverse effect on the sale price of smaller properties could be greater than effect on the sale price of larger properties.

---

[420] Pub. T., Tab 3, Bennett (Alexandria); Tab 18, Easter (Rochester); Pub. Comm., Maass, filed 10/06/08, #5551877; Lusk, filed 7/31/08, #5405095.
[421] *See* Ex. 308 at 3 (Rakow Statement).
[422] Ex. 56 at 37 (Webb Direct); Ex. 257 at 4-5 (Ham Direct).
[423] Ex. 56 at 37 (Webb Direct); T. 4 at 156 (Webb).
[424] Ex. 1 at Chapter 8, Ex. 2 at E-1, E-2, E-3 (Application).
[425] Pub. T., Tab 5, Lieder, Shore, Sypnieski (Clearwater); Tab 11, Magnussen (New Prague); Tab 13, Herschberger-Ligan (Lakeville); Tab 18, Easter (Rochester).

c. Other amenities, such as proximity to schools or jobs, lot size, square footage of a house and neighborhood characteristics, tend to have a much greater effect on sale price than the presence of a power line.

d. The adverse effects appear to diminish over time.

e. Effects on sale price are most often observed for property crossed by or immediately adjacent to a power line, but effects have also been observed for properties farther away from the line.

f. The value of agricultural property is likely to decrease if the power line poles are placed in an area that inhibits farm operations.[426]

371. The ER reached no conclusion about the effects on property value except to state: "In the matter of property values, potential impacts would typically be negotiated in an easement agreement between the Applicants and the landowner."[427] However, some members of the public objected that the eminent domain process was inherently unfair because of the power imbalance between an individual landowner and the utility.[428]

372. New transmission lines will have a significant visual impact.[429] Several members of the public expressed their concern about the impact the towers would have on the aesthetics of rural areas.[430] Typically, both a single-circuit 345 kV line and a double-circuit 345 kV line require a 150-foot right-of-way. The 161 kV lines require 70 to 80 feet of right-of-way. The right-of-way may be narrower where it follows a pre-existing transmission line, road or pipeline corridor. Typically, the towers for 345 kV single-circuit lines will be 105 to 150 feet high, with approximately 750 to 1100 feet between spans. Double-circuit 345 kV lines will be 130 to 175 feet high, with approximately the same spans. The lower voltage lines typically have lower towers but shorter spans.[431]

373. Since much of the land in the proposed corridors is flat or rolling and open, the structures and lines will be visible from long distances. The visual impact can be somewhat minimized during the siting, but for most people the overall aesthetic effect would be negative. The Environmental Report identified areas of high visual sensitivity and possible mitigation.[432] Placement under ground is not practical in light of the length of the lines and the associated expense. In addition, underground are more difficult and expensive to maintain and repair.[433]

---

[426] Ex. 5 at 14.
[427] *Id.*
[428] Pub. T., Tab 10, Mayer (Arlington); Tab 13, Topp (Lakeville).
[429] Ex. 1 at 8.3 (Application).
[430] Pub. Comm., Bigaouette, filed 7/31/08, #5405084; Chipps, filed 10/6/08, #5551878; VanOverbeke, Groshek, Howe, Morse, filed 10/06/08, #551881; Miller, filed 10/06/08, #5520590.
[431] Ex. 1 at 2.10 (Application).
[432] Ex. 5 at 17-19.
[433] Ex. 1 at 2.11 (Application).

374. Human settlement, including homes and potential development, will be affected.[434] Lezlie and Jason LaVoy of Milroy would prefer to have a wind turbine on their farm than a transmission tower, which could affect their electronic equipment and ability to farm.[435] Elmer Green lives on a farm in Lynd. He supports the need for a power line but wants the line to bypass housing, and to avoid damaging farm drainage systems or having an adverse effect on his ability to farm.[436] Keith and Cheryl Miller of Marshall fear that the transmission line could run within 120 feet of their home. Dan and Rose Bot of Cottonwood advocate for running the lines along road and railroad rights-of-way to minimize the effect on homeowners.[437]

375. All three projects would affect agricultural lands, including significant "prime farmland," as defined by federal law.[438] Some citizens expressed their concern about the loss of forest and agricultural land[439] and about the detrimental impact the CapX projects could have on private land and the ability to farm.[440] James Mayer, speaking on behalf of Cornish Township, said that the utilities' heavy equipment damaged township roads during previous construction and that the townships were not adequately compensated for the damage.[441]

376. Since the routing process has not begun, there are no estimates in this record of the amount of new or expanded right-of-way that would be required or the proportion that would follow existing rights-of-way.

377. There are archeological sites and historic sites in each project area.[442]

378. Threatened and endangered species are found along virtually every segment of the three project corridors, and each of the three projects could have an impact on them.[443] Danger to migrating birds was a special concern for many members of the public. John and Susan Greening and Reverend Howard Larsen of La Crescent,[444] and Jeanne Dukerschein, a natural resources professional in La Crescent, feared that the La Crosse Project could damage and fragment habitat with a negative effect on the migrating birds. Her concern was shared by Julia Crozier of Fountain City, who noted that the river birds and other river animals are already under major environmental stress, with a resulting decline in species on the river.[445]

---

[434] Ex. 1 at 8.4 (Application).
[435] Pub. Comm., LaVoy, filed 10/06/08, #5551881.
[436] Pub. Comm., Green, filed 9/24/08, #5520583.
[437] Pub. Comm., Miller, Bot, filed 9/24/08, #5520590.
[438] *See,* 7 C.F.R. § 657.5 (a)(1).
[439] *See, e.g.,* Pub. T., Tab 18, Easter, Forhan (Rochester); Tab 11, Pickit, Hartung (New Prague); Tab 12, Otto (Lakeville); Tab 15, Friend (Cannon Falls).
[440] Pub. Comm., Henry, LaVoy, Van Schaik, Bot, Kluver, Van Keulen, filed 10/06/08, #5551881; Tupy, affidavit, # 5551879; Rohlik, filed 10/06/08, #5551880; Prchal, Bot filed 9/24/08, #5520590.
[441] Pub. T., Tab 10, Mayer (Arlington).
[442] Ex. 1 at 8.4 (Application).
[443] Ex. 1 at 8.3 (Application); Ex. 5, Part 3.0.
[444] Pub. Comm., Greening, filed 8/25/08, #5464476; Larsen, filed 9/22/08, #5518689.
[445] Pub. Comm., Duckershein, filed 9/22/08, #5518690; Crozier, filed 6/18/08, #5286821. *See also,* Pub. T., Tab 17, Joe Morse, Bluff Land Environment Watch (Winona).

379. Several public comments, including those by Xcel Energy stockholders Leo and Marilyn Smith, addressed the possible degradation of the beautiful Mississippi River bluffs, scenic by-way, and adjacent protected land that provides crucial habitat for plants and animals.[446]

380. During the routing process, more detailed information will be collected. However, the Applicants concluded that, based on the level of review required for the certificate of need, there were no environmental issues that would preclude construction of these facilities.[447]

381. The ER concluded that the proposed projects will have a significant impact on the land that they traverse, and that, in particular, the projects will require approaching, crossing or proximity to the Minnesota and Mississippi Rivers:

> The Minnesota River and Mississippi River valleys contain large tracts of state and federally protected lands, many cities, biologically outstanding lands, high scenic values, and cultural resources. *In most cases* the mere presence of these resources does not prohibit new or rebuilt transmission infrastructure, [but] the presence of and potential impacts to these resources may limit routing options or require special mitigation measures. The presence of and potential impacts of these resources are an important factor for the public and the PUC to consider at the [certificate of need] and at the routing stages of the regulatory process.[448]

382. There are alternatives for river crossings. However, both overhead and underground alternatives require cleared rights-of-way for construction and maintenance, both will disrupt the river during construction and both will have a visual impact on each shore. Underground facilities are generally 10 times more costly than overhead facilities, more difficult to repair, and may require more equipment and time to construct. Construction of underground facilities may also pose greater environmental risk.[449]

383. The ER did not recommend specific mitigation or reach a conclusion about whether any route could be found within the proposed corridors that would do no lasting damage to the Minnesota River and Mississippi River valleys. However, the OES witness opined that each corridor had at least one possible route with feasible river crossings that, with proper mitigation, would not significantly degrade the natural environment.[450]

---

[446] Pub. T., Tab 17, Smith (Winona), and Pub. Ex. 32; Pub. Comm., Edon, Hammes, Heisel, filed 9/22/08, #5518690; Blum, Timmerman, filed 8/25/08, #5464476; Acevedo, Krenz, Morse, Howe, filed 10/06/08, #5551881; Cerwin, Karoll, Breidel, filed 9/24/08, #5520590; Eisley, Larsen, filed 9/22/08, #5518689.
[447] Ex. 1 at 8.1 (Application); Ex. 128 at 6, 12,13,19 (Rasmussen Direct).
[448] Ex. 5 at 93 (emphasis added).
[449] Ex. 1 at 9.10-9.11 (Application).
[450] T. 18A at 27-29, 33-34, 37-38, 44-45 (Birkholz).

384. In addition to the overall impact of the projects, each of the three projects has specific environmental considerations.

385. For the La Crosse Project, consideration must be given to minimizing the impact of major crossings of the Mississippi and Cannon Rivers, routing and construction in the forested and bluffland areas in the southern portion of the project area, and routing in the densely populated areas of Rochester, La Crosse and Winona.[451] The ER identified a 350-acre area north of Rochester called "Evergreen Acres" that contains some of the largest areas of undeveloped lands and habitat in Olmsted County and several endangered species. Conservation easements have been placed on the land. Efforts should be made to avoid interrupting contiguous natural features and unfragmented parcels.[452] The Applicants' environmental analysis included discussion of the issues related to the Prairie Island Substation, but the Applicants dropped that substation connection from the La Crosse Project.[453]

386. For the Fargo Project, consideration must be given to routing near extensive water features in the central portion of the project area, the Mississippi River migratory flyway, sensitive scenic resources, including scenic by-ways, routing in the densely populated areas around Fargo, Stearns County and Monticello, and the feasibility of routing along the Interstate 94 Corridor.[454]

387. The ER gave special attention to the large Avon Hills area of Stearns County, which includes Avon and Collegeville Townships and parts of four others. It includes an "Important Bird Area," one of the most critical areas in the state for the conservation of bird populations. Avon Hills includes wildlife protection areas managed by the U.S. Fish and Wildlife Service and two DNR Scientific and Natural Areas. Clearing a corridor for the transmission lines through the area could significantly fragment the habitat with a serious impact on the many forest bird populations. Efforts are underway to protect approximately 50,000 acres because "a significant proportion of the remaining natural vegetation and rare plants and animals of the entire county lie within this relatively small geographic area." The area is shown on Map 12 of the ER.[455]

388. For the Brookings Project, consideration must be given to minimizing the impact of major crossings of the Mississippi, Minnesota and Redwood Rivers, impact on migratory birds, routing and construction in prime farmland, gneiss outcroppings near Granite Falls, several Scientific and Natural Areas, sensitive scenic resources, impact on the Upper Sioux Community and Lower Sioux Community, and routing in the densely populated areas in Scott, Carver and Dakota Counties.[456] In particular, the Minnesota River Valley presents several challenges because of its scenic resources and archeologically rich areas. Crossing to the Minnesota Valley Substation will be difficult

---

[451] Ex. 1 at 8.5-8.22 and Ex. 2, E-1 (Application); Ex. 128 at 7-12 (Rasmussen Direct).
[452] Ex. 5 at 49.
[453] Ex. 2, E-1 at 56.
[454] Ex. 1 at 8.22-8.27 and Ex. 2, E-2 (Application); Ex. 128 at 12-13 (Rasmussen Direct).
[455] Ex. 5 at 63.
[456] Ex. 1 at 8.27-8.36 and Ex. 2, E-3 (Application); Ex. 128 at 14-19 (Rasmussen Direct).

because of the variety of natural resources at the crossing, including threatened and endangered species, prairie and wetlands, and the constrained area.[457]

389. The ER reiterated the challenge of crossing the Minnesota River and possible degradation of its river valley with its "outstandingly remarkable values of national significance (scenery, recreation, wildlife, and history)," and the need to protect the Minnesota Valley Scenic Byway that parallels the river.[458]

390. If approved, routing approvals and other local, state and federal approvals would be required. A list of possible permits is included in the Application at 8.37-8.38. Many of the permits are intended to mitigate environmental impact.

391. A transmission line's operating characteristics have an effect on the natural environment. Some chemical reactions, noise, electric and magnetic fields and interference with electromagnetic signals occur around conductors.

<u>Ozone and Nitrogen Oxide Emissions</u>

392. Corona is an ionization of air within a few centimeters of the conductor. This breakdown of air around the conductors can generate audible noise, radio frequency noise, light, ozone, other products and energy loss. Any imperfection or irregularity on a conductor, including a scratch or water droplet, can cause corona. During good weather, discharges are insignificant. However, during wet weather, water droplets on the conductor's surface increase corona discharges.[459]

393. Corona can produce ozone and oxides of nitrogen. However, because the natural production rate of ozone is directly proportional to temperature and sunlight, and inversely proportional to humidity, the same factors that increase corona discharges from transmission lines inhibit production of ozone. Ozone is very reactive and is relatively short-lived.

394. The national standard for ozone emission into the air is 0.08 parts per million (ppm) for an eight-hour average period, and the state standard is 0.08 ppm based upon the fourth-highest eight-hour period daily maximum average in one year. The 0.0007 ppm concentration for a 345 kV transmission line is well below the federal and state standards.[460]

<u>Audible Noise</u>

395. Audible noise generally increases with the voltage of the line – the higher the voltage, the higher the noise.[461] In Minnesota, statistical sound levels (L Level Descriptors) are used to evaluate noise levels and identify noise impacts. L_5 is defined

---

[457] Ex. 2, E-3 at 45-46 (Application); Ex. 128 at 14-15 (Rasmussen Direct).
[458] Ex. 5 at 77.
[459] Ex. 1 at 9.17 (Application); Ex. 126 at 2-3 (LaCasse Direct).
[460] Ex. 1 at 9.17-9.18 (Application); Ex. 126 at 3 (LaCasse Direct).
[461] T. 12 at 141, 153 (LaCasse).

as the noise level exceeded 5 percent of the time, or for three minutes in an hour. The L_{50} is the noise level exceeded 50 percent of the time, or for 30 minutes in an hour. Land areas are assigned to an activity category based on sensitivity to traffic noise. The Noise Area Classification (NAC) is listed in the Minnesota Pollution Control Agency (MPCA) noise regulations to distinguish the categories.[462] Household units, including farm houses, are included in Category 1,[463] with the following noise limits, recorded in units of decibels (dBA):

Daytime: L_{50} – 60; L_{10} – 65

Nighttime: L_{50} – 50; L_{10} – 55.[464]

396. Figure 9-8 of the Application summarizes the audible noise associated with transmission lines of the type included in the CapX projects, under wet conditions with the highest audible noise levels.[465] The figure shows that the noise level at the edge of the right-of-way for a 345 kV double-circuit line has an L_5 level of 57.7 dBA, which is higher than the nighttime L_{10} noise limit. The L_{10} level is not included in the chart. A 345 kV double-circuit line has an L_{50} noise level of 49.9 dBA, barely below the nighttime limit. None of the other values on the chart exceed the MPCA noise limits. To assure compliance with L_{10} and L_{50} nighttime limits, household units must be sufficiently far from the edge of the 345 kV double-circuit right-of-way.[466]

Radio and Television Interference

397. Corona from a transmission line can interfere with the reception of television and AM radio signals. AM radio interfence typically occurs directly under a transmission line and dissipates rapidly within the right-of-way. Television interference can be addressed by the utility to assure that quality reception is maintained.[467]

Electric and Magnetic Fields

398. Electric and magnetic fields (EMF) are present around any electrical device. Electric fields are the result of voltage or electrical charges, and the intensity of the electric fields are related to the operating voltage of the line or the device. EMFs are the result of the flow of electricity or current that travels along transmission lines, distribution lines, substation transformers, house wiring and household electrical appliances. The intensity of a magnetic field is related to the current flow through the wires.

---

[462] Ex. 1 at 9.20 (Application).
[463] Minn. R. 7030.0050.
[464] Minn. R. 7030.0040, subp. 2.
[465] Ex. 1 at 9.18-9.19 (Application); Ex. 126 at 5 (LaCasse Direct).
[466] Although the transmission towers for a 345 kV single or double-circuit line will be 100 feet tall or more, for the purpose of this calculation, the analysis is based on the estimated low point of the line between towers, 36 feet above the ground. T. 12 at 140 (LaCasse).
[467] Ex. 1 at 9.21-9.22 (Application); Ex. 126 at 6 (LaCasse Direct); T. 12 at 150 (LaCasse).

399. There has been a great deal of research conducted to determine whether exposure to power-line-level EMF causes biological exposure and health risks. The issue has been addressed in several prior proceedings before the Commission, and has not been of sufficient concern to prevent construction of new transmission lines. Neither the state nor federal government has established limits on exposure to magnetic fields.

400. Several members of the public expressed their concern about the health effects of the transmission lines, including the possible links to cancer.[468] Joe Kenning spoke of the adverse effects a nearby line has had on his family's personal health and on his livestock.[469] Robert Dahse has worked in the renewable energy field for many years. He cited studies linking EMF exposure to adverse health effects.[470] Jan Rohwer of Greenvale Township expressed concern about the cancer deaths in her family.[471]

401. Because of the continued uncertainty and public concern, the Minnesota Department of Health recommends a "prudent avoidance" policy to minimize exposure.[472]

402. Transmission lines can induce "stray voltage" when an electric distribution line runs parallel or under a transmission line. If not properly grounded, the voltage on the line may move to the ground through an object that comes in contact with it.[473] The Applicants have committed to taking appropriate measures to prevent stray voltage problems when the transmission lines parallel or cross distribution lines.[474]

403. The ER discussed the general effect of new transmission lines on noise, radio and television interference, and human health and safety, including exposure to electric and magnetic fields and stray voltage. It concluded that proper placement and installation of the lines should protect the public.[475]

404. The ER commented specifically on the World Health Organization's recent review of the health implications of electromagnetic fields, and, in particular, the possible link between exposure and incidence of childhood leukemia. Although the WHO could not conclude that there was a causal link, there is still troubling evidence of increased risk of childhood leukemia associated with average exposure to residential power-frequency magnetic field of about 0.3 to 0.4 micro Teslas (0.03 to 0.04 milliGauss).[476] This average exposure range is several times less exposure than the

---

[468] Pub. T., Tab 15, Rohwer (Cannon Falls); Pub. Comm., Hanson, Donabauer, filed 8/08/08, #5417357.
[469] Pub. T., Tab 5, Kenning (Clearwater).
[470] Pub. Comm., Dahse, filed 9/22/08, #5518686.
[471] Pub. T., Tab 15, Rohwer (Cannon Falls). *See also*, Pub. Comm., Dahse, filed 9/22/08, #5518686; Teschler, filed 8/25/08, #5464470; Magnussen, filed 8/25/08, #5464472; Hanson, Donabauer, filed 8/08/08, #5417357.
[472] Ex. 1 at 9.24 (Application); Ex. 126 at 6 (LaCasse Direct).
[473] T. 12 at 159-160 (LaCasse).
[474] Ex. 1 at 9.31 (Application).
[475] Ex. 5 at 28-29.
[476] Ex. 5 at 27; *see also,* Pub. Comm., Otto, filed 9/24/08, #5520587 (August 31, 2007, BioInitiative Report: A Rationale for a Biologically-based Public Exposure Standard for Electromagnetic Fields (ELF and RF)).

"Peak Magnetic Field at ROW Edge," in milliGauss (mG), expected for the three projects. The estimated "Peak Magnetic Field at [right-of-way] Edge" is estimated to range from 0.4 mG to 92 mG, and the largest number of estimates for the various components of the projects clustered between 15 and 30 mG.[477] The record is unclear about the distance from the proposed projects that would be required to reduce the exposure level below 0.3 to 0.4 micro Teslas.[478]

405. The ER pointed out that there are many sources of exposure to magnetic fields, including household appliances and computers, although it is difficult to compare the typical length of exposure.[479]

406. Many members of the public expressed concern about the lack of definitive evidence that exposure to transmission lines is safe, including some who have felt the effects of nearby lines or stray voltage, and requested extra precautions.[480]

407. In light of the on-going concern about the possible effects of the transmission projects, members of public recommended use of the "precautionary principle," routing the transmission lines to avoid human exposure and minimize the possible health impact.[481] Members of the public offered suggestions to mitigate EMF, including wider easements, additional technology to sheathe power lines, and elimination of the higher voltage lines.[482]

Effect of CapX on Development of Coal Generation

408. There was considerable controversy during the proceeding about whether the proposed projects would stimulate additional coal generation in North or South Dakota. Many assumed that the CapX projects would be a conduit for coal generation and expressed their concern about coal generation's greenhouse gas emissions, contribution to global warming, and general unsustainability.[483]

409. One basis for the concern was that the Fargo Project will increase the North Dakota Export limit, the amount of electricity that can be transmitted from the west into Minnesota. The source of the generation is neither determined nor limited by this proceeding. It is not possible on this record to assign a probability to the concern that coal generation will connect and flow into Minnesota. Other proceedings will dictate whether and where new coal generation develops, and MISO will determine the specific

---

[477] Ex. 5 at 25-26.
[478] *See* T. 18A at 31 (Birkholz).
[479] Ex. 5 at 26.
[480] *See, e.g.*, Pub. T., Tab 6, Hagerstrom, Zabinski (Clearwater); Tab 7, Dacey (Marshall); Tab 9, Turbes (Redwood Falls); Tab 11, Ruhland (New Prague); Pub. Comm, Otto, filed 9/24/08, # 5520590; Beach, filed 7/31/08, # 5405084; Holleran, filed 10/06/08, #5551881, Babcock, filed 9/24/08, #5520585.
[481] Pub. T., Tab 13, Diffley (Lakeville); Pub. Comm., Dailey, filed 8/08/08, #5417357, Brown, filed 8/25/08, #5464476, Turner, filed 9/22/08, #5518690.
[482] *See, e.g.,*. Pub. Comm., Otto, Filed 9/24/08, #5520590.
[483] *See, e.g.,* Pub. T.,Tab 15, Moskl, Halley (Cannon Falls); Tab 13, Frerichs (Lakeville); (*see also* Public Hearing Ex. 18); Tab 12, Topp, Olstad, Budenski (Lakeville); Tab 17, T. Tollefson (Winona); Tab 19, Hoffman, Muller-Green (Rochester); Tab 16, Paddock (Winona). *See also,* Pub. Ex. 14, 15, 16.

generation that will connect to the proposed projects. However, with the enactment of the Minnesota Greenhouse Gas Emission law, it is unlikely that new coal generation will develop in this state, and the same law may discourage development to the west to meet Minnesota load.

410. MISO's planning document, MTEP 2007, includes 229 active projects, of which 33 have signed interconnection agreements and expected in-service dates prior to 2016. These are expected to add 7,945 MW of capacity to the MISO market footprint, 4,511 MW of coal projects, 1,805 MW of gas-fueled, combined-cycle projects and 1,008 MW of wind projects. None of these projects have interconnection agreements conditioned on the Brookings Project. Conversely, none of these projects would be displaced from their positions in the queue by interconnecting additional wind projects to the Brookings Project.[484]

411. Some parties and members of the public feared that the CapX projects would support Big Stone II expansion and objected to any project that would facilitate that expansion and its mercury emissions.[485] There is no evidence that the CapX projects are needed to serve Big Stone II. The CapX projects are not included in the Big Stone II transmission studies, and Big Stone II has an interconnection request at MISO that does not involve connection to any of the CapX facilities.[486] It is not possible to determine what effect, if any, subsequent changes in Big Stone II will have on the CapX projects.

412. Some parties and many members of the public were concerned that the CapX project was a subterfuge to move coal-fired power from points west of Minnesota to Minnesota or states to the east. Neither OES, nor MCEA witness Ellison, could find any rational basis for this concern.[487] The basis for the study, analysis, and design of CapX was to serve Minnesota load.[488]

413. Although there was evidence that up to 600 MW of dispersed generation could be sited without construction of new generation, there was no specific alternative presented that would alleviate the need for any one of the three projects. Moreover, the DRG Study presumed that dispersed generation would replace existing generation, not supplement it. Thus, even if more dispersed generation was added, it would not reduce the projected need for new generation and new transmission to connect to it.

414. The ER included the required review of specified alternatives.[489] Alternatives were not discounted because they could not meet all of the identified need,

---

[484] Ex. 59 at 37; T. 5B at 17-20 (Webb).
[485] NAWO/ILSR Posthearing Brief at 16; NoCapX Posthearing Brief at 21; CETF Posthearing Brief at 54; Pub. T., Tab 2, Wika (Fergus Falls); Tab 3, Campbell, Jensen (Alexandria); Tab 16, Paddock (Winona); Pub. Comm. Pierce, filed 10/116/08, #5567282; Braun, filed 9/22/08, #5518690; Schoofs, filed 8/08/08, #5417357; Crozier, filed 6/18/08, #5286821.
[486] T. 2B at 61 (Rogelstad) T. 10 at 127 (Alholinna).
[487] Ex. 303 at 30-31 (Rakow Rebuttal);T. 25 at 73, 80-81 (Rakow); T. 24 at 66-69 (Ham); T. 21 at 49 (Ellison).
[488] *See, e.g.*, T. 25 at 73 (Rakow).
[489] Minn. R. 7849.7060, subps. 1 and 6. No alternatives were offered for consideration.

but were evaluated for what they could contribute to the need, and the environmental impact.[490] Among those, it evaluated an alternative with transmission sufficient to provide outlet for 800 MW of wind generation and four natural gas generation facilities with associated pipeline and transmission infrastructure to provide new generation in Rochester, La Crosse, Alexandria and Saint Cloud. This was referred to as the "generation alternative."[491]

415. Although the generation alternative could be constructed, it did not achieve comparable regional reliability or local load-serving and could require significant investment in transmission infrastructure.[492]

416. The ER evaluated whether conservation or demand-side management could replace the 4000 to 6000 MW of increased demand identified by the Applicants, but did not analyze whether a smaller portion of the increased demand could be met by either conservation or demand-side management.[493] OES acknowledged that over time, greater energy savings are likely, but because most Minnesota utilities have not yet achieved the level of energy savings required by the conservation statute, it made no effort to factor a reduction into the demand through 2020 that would exceed the statutory requirement.[494]

417. The RES reflect Minnesota's policy to promote increased renewable generation. Because of the wind resources available, it is anticipated that much of the RES will be met with wind, and, in particular, that Xcel will require additional wind development to meet its RES milestones. Transmission limitations are the most significant barrier to wind energy development.[495] Although the Applicants cannot limit access to transmission lines to wind generation, construction of additional transmission lines is essential to interconnecting additional wind generation.[496]

Economic Benefits of Construction and Operation

418. The ER concluded that there are likely to be short-term increases in spending during construction that may benefit the local economy, but no additional permanent jobs created by the projects. The new transmission lines, new substations, and upgrades to existing facilities may increase local tax base with incremental increase in revenues from utility property taxes.[497]

419. Applicants estimate that 200 to 250 workers will be employed on the three projects, spread across the worksites. Long-term, the transmission lines and substation additions will increase local tax base resulting from the incremental increase in

[490] Ex. 5 at 78-79.
[491] Ex. 5 at 80.
[492] Ex. 5 at 89-90.
[493] Ex. 5 at 90; T. 17B at 9 (Birkholz).
[494] *Id.*
[495] Ex. 171 at 10 (Gramlich Direct).
[496] Ex. 56 at 33 (Webb Direct); T. 5B at 23-24 (Webb).
[497] Ex. 5 at 13.

revenues from utility property taxes. Nearby communities may have some short-term benefit from expenditures by workers during construction.[498]

420. Transmission lines require little maintenance and are typically available 99 percent of the time. The principal operating and maintenance cost is for regularly scheduled inspections - monthly by air, and once a year on the ground. Substations require periodic site and equipment maintenance.[499]

421. Overall, the proposed transmission lines will reduce line losses and the associated pollution including greenhouse gases, relative to the level without the CapX projects.[500] Moreover, since the source of generation that will be served is not known, the incremental impact of varying forms of generation cannot be assessed.

422. Renewable energy generation is intended to reduce greenhouse gases. Using the 2,275 MW of renewable energy included in the Vision Study, MCEA estimated that the CapX projects will reduce CO_2 emissions by almost 5 million tons. This is far in excess of the 500,000 tons of CO_2 that NAWO/ILSR estimated would be created by 700 miles of construction for the CapX projects.[501]

423. In summary, the proposed transmission lines will have a substantial impact on the natural and socioeconomic environment, but no reasonable and prudent alternative with less impact has been shown that can meet the need for the CapX projects.

B (4). The Expected Reliability of the Proposed Facility, Relative to Reasonable Alternatives.

424. The NERC planning standards define reliability of the interconnected transmission system using two terms: adequacy – ability to provide customers with a continuous supply of electricity at the proper voltage and frequency virtually all of the time; and security – the ability of the system to withstand sudden, unexpected disturbances such as short circuits or unanticipated loss of system elements.[502]

425. The CapX projects are part of a longer-term plan to strengthen the transmission network to meet additional demand for electrical power anticipated by 2020 in Minnesota and parts of the surrounding states. The CapX projects are designed to increase the reliability of the overall transmission system and the reliability of service to five local areas. No alternative was proposed that would meet those needs.

---

[498] Ex. 1 at 9.15-9.16 (Application).
[499] Ex. 1 at 9.16-9.17 (Application).
[500] *See,* Ex. 282 at 47-53 (Rakow Direct); Ex. 303 at 31-33 (Rakow Rebuttal); Ex. 307 at 2-3 (Rakow Surrebuttal).
[501] Ex. 140 at 31-32 (Michaud Direct); Ex. 175 at 204 (Gramlich Rebuttal); *see also,* Ex. 303 at 32 (Rakow Rebuttal); Ex. 308 at 3 (Rakow Statement).
[502] Ex. 257 at 6-8 (Ham Direct), citations omitted.

426. No party has demonstrated by a preponderance of the evidence that there is a more reasonable and prudent alternative to the Applicants' proposed project.

C. The Applicants Must Show that the Proposed Facility or a Suitable Modification Will Provide Benefits to Society Compatible with Protecting the Natural and Socioeconomic Environments, including Human Health.

427. The benefits of the project are increased regional reliability, more reliable service to several communities, and increased generation outlet for renewable energy.

C (1). The Relationship of the Proposed Facility, or a Suitable Modification, to the State Energy Needs.

428. The CapX projects will strengthen the transmission network to meet additional demand for electrical power anticipated by 2020 in Minnesota and parts of the surrounding states. The CapX projects will increase the reliability of service to Minnesota customers. They will also improve the ability of the transmission system to meet overall state energy needs, including compliance with the RES. No alternative was proposed that would meet those needs.

429. The proposed projects will have a significant positive effect on community reliability in Rochester, La Crosse, Southern Red River Valley, Alexandria and Saint Cloud.[503]

C (2). The Effects of the Proposed Facility Relative to Not Building the Facility.

430. The No Build Alternative would have no impact on the natural and socioeconomic environment, but the demonstrated needs for increased regional reliability of the transmission system, improved community reliability, and enhanced generation outlet cannot be met if the facilities are not constructed.

431. Some of the parties and many members of the public contend that the proposed projects will not protect or enhance the environment, but, instead, will significantly contribute to its degradation. The construction and siting of large transmission structures will have a detrimental visual effect, disturb miles of farmland, and require the taking of private property from property owners who value their land and their rural surroundings. In addition, crossing pristine areas, including but not limited to the Minnesota and Mississippi Rivers, may disturb wildlife and protected habitat. These effects should not be minimized during the routing proceeding.

432. Construction of the CapX projects will have an impact on air quality and may disturb surface water, flora, and fauna during construction. The operation of the projects will have limited air emissions.[504]

---

[503] Ex. 257 at 1, 9-10, 19 (Ham Direct); Ex. 274 at 2 (Ham Surrebuttal).
[504] Ex. 5 at 35, 37.

433. The CapX projects may interfere with the function of wetlands, lakes, rivers, and floodplains. There may be a loss of habitat, including habitat for threatened and endangered species, within the project corridors.[505]

434. There are no known environmental issues associated with the proposed configuration that would preclude construction.[506]

435. Some homes, forests, and prime farmland, may be lost or adversely affected by the proximity of the transmission lines.[507]

436. There may be a temporary influx of wages and expenditures during construction.[508]

437. If the facilities are not built, the region and some communities may experience unreliable electrical service and poor voltage support, and there will continue to be limited opportunity for generation outlet from the western part of the state.[509] Every effort should be made during routing and construction to avoid harmful effects on the natural environment and, where damage is unavoidable, to significantly mitigate the impact.

C (3). The Effects of the Facility, or a Suitable Modification Thereof, in Inducing Future Development.

438. The CapX projects will address the anticipated demand growth in the project areas and throughout the transmission system. There was some concern that the location and size of the lines would inhibit the development of dispersed, small-scale wind projects, but the evidence shows that the CapX project will increase generation outlet and create the infrastructure to facilitate additional development of renewable resources.

C (4). The Socially Beneficial Uses of the Output of the Proposed Facility, or a Suitable Modification, Including Its Uses to Protect or Enhance Environmental Quality.

439. There are beneficial uses of the electricity that will be carried on these lines. There is substantial evidence that the regional stability of the electrical system and the immediate needs of several communities will require the additional capacity these projects will provide. Additional transmission lines are needed to increase the opportunity to develop new generation to help meet future RES milestones. The CapX projects will also lower line losses, with the effect of reducing generation of CO_2.

---

505 Ex. 5 at 36-38.
506 Ex. 128 at 6 (Rasmussen Direct); Ex. 5.
507 Ex. 5 at 13-14, 31.
508 Ex. 5 at 13.
509 Ex. 5 at 35, 80.

440. The Applicants have demonstrated that the proposed facilities will benefit society in a manner compatible with protecting the natural and socioeconomic environments.

D. The Design, Construction, or Operation of the Proposed Facility, or a Suitable Modification, Will Comply with Relevant Policies, Rules, and Regulations of Other State and Federal Agencies and Local Governments.

441. The Applicants intend to comply with all relevant policies, rules, and regulations of state and federal agencies and local governments applicable to construction and operation of the proposed transmission lines.[510] A list of required permits is set forth in the Application.[511]

442. OES reviewed the Applicants' list of permits. It had no reason to believe that the permits would not be granted, but deferred to the agencies for enforcement of their permit requirements.[512]

443. NAWO/ILSR asserted that the Applicants cannot demonstrate that the CapX projects will comply with applicable laws and policies.[513] It cited policies that are aimed at reducing greenhouse gas emissions. However, it failed to cite any specific policy or regulation that this project would violate.

444. The record does not demonstrate that the design, construction, or operation of the proposed facilities, or the specified modifications, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

Proposed Conditions

445. In granting the certificate of need, the Commission may impose modifications that it deems necessary.[514]

<u>Limiting New Generation Outlet To Renewable Energy</u>

446. MCEA asserted that the certificates of need for each of the three projects should be subject to conditions imposed by the Commission that would ensure that any new generation outlet capacity would be dedicated to renewable energy. The Brookings Project is expected to provide approximately 700 MW of additional generation outlet capacity in the Buffalo Ridge area.[515] The Fargo Project will cross a wind-rich area in northwestern Minnesota and eastern North Dakota and provide additional generation support of approximately 350 MW.[516] The La Crosse Project is

---

[510] Ex. 1 at 1.21 (Application).
[511] Ex. 1 at 8.37-8.38 (Application).
[512] Ex. 282 at 83-84 (Rakow Direct).
[513] NAWO/ILSR Post-hearing Brief at 19 *et seq*.
[514] Minn. Stat. § 216B.243, subd. 5.
[515] Ex. 104 at 2, 5 (Alholinna Direct).
[516] Ex. 67 at 12 (Kline Direct); Ex. 70 at 7 (Kline Rebuttal).

expected to enhance the deliverability of wind generated power from southeastern Minnesota and, in cojunction with the RIGO projects, will allow outlet capability beyond 900 MW and assist utilities in meeting the 2016 RES milestones.[517]

447. MCEA witness Schedin concluded that all three projects would create new generation outlet capacity.[518]

448. MCEA proposed several conditions to assure that new generation outlet capacity will be dedicated to renewable generation:

> a. Applicants sign power purchase agreements (PPAs) with renewable energy developers or commit to utility-owned renewable generation projects to use the new capacity on the transmission lines at least two years prior to the expected in-service date of those lines; and seek Commission approval of those commitments within six months of execution.
>
> b. Applicants make a compliance filing within 30 days of obtaining the certificates of need, detailing the allocation of the new transmission capacity among the Applicants. The compliance filing must address: how much capacity will be enabled by the three new transmission lines; the allocation of the capacity among the Applicants; and the type of MISO transmission service the Applicants will seek to serve the renewable-generated electricity to be carried on the three CapX projects.
>
> c. Applicants sign PPAs or commit to utility-owned renewable generation projects within the timeframe of the Minnesota RES milestones, or earlier, depending on the proposed in-service dates of each segment of the three transmission lines.
>
> d. Applicants commit to submit network (firm) transmission service requests to MISO Open Access Same Time Information System (OASIS) for the total amount of new capacity enabled by the three transmission lines to ensure full subscription of the capacity for renewable generation.
>
> e. As necessary to comply with condition (a), Applicants designate the new renewable commitments as Network Resources pursuant to the MISO TEMT, and seek the designation as soon as permitted under the MISO rules, but no later than 10 days after the Commission approves the PPAs or commitments.
>
> f. Applicants report to the Commission any changes at MISO or the federal level that could affect the conditions.[519]

[517] Ex. 98 at 2-3 (King Rebuttal).
[518] Ex. 177 at 5-7 (Schedin Direct).
[519] Ex. 213;

449. MCEA asserted that the conditions assure that the new generation outlet is used for the purpose upon which the Applicants' need is based, supporting renewable generation outlet. Its first condition was its most imporatnt: entering into commitments at the expected level of outlet generation at least two years before the transmission lines are expected to be in service. Utilities' commitments to purchase or own renewable energy are critical to the development of those projects. Changes to the MISO interconnection process require a signed PPA or ownership by the load-serving entity to move the project through the queue. By requiring signed PPAs, MCEA believed that the transmission lines will in fact promote renewable generation. The remaining conditions would assure that the contracted or owned renewable energy projects will be interconnected and obtain transmission service in a timely manner coincident with the in-service dates of the CapX lines.[520]

450. MCEA's proposed conditions are intended to fully utilize the firm transmission capability of the new lines, but would not preclude the use of the lines by other non-renewable facilities. To the extent renewable energy is not available due to weather or other circumstances, nonrenewable energy would have access in the real-time market to the facilities.[521]

451. Changes in the MISO queue process allow projects to move through the queue by achieving designated milestones. Projects that achieve the milestones can move ahead of those that do not. In the opinion of MCEA, a signed PPA or utility commitment to purchase the power is necessary to meet one of the key milestones.[522]

452. The Applicants, OES and MISO opposed the proposed conditions. CETF supported MCEA's proposed conditions for the Brookings Project.[523] NAWO/ILSR would deny the certificate of need for the Brookings Project, but if the certificate of need is granted, it favored imposing conditions to assure that generation outlet will be used for wind energy and outweigh the adverse greenhouse gas emissions from construction activities.[524] UCAN and NoCapX did not address the proposed conditions.

453. MCEA relied upon the Commission's order in the "825 MW Proceeding," issuing a certificate of need for four transmission lines in southwestern Minnesota, as precedent for the conditions that it is requesting in this proceeding.[525] The Applicants and OES distinguish the 825 MW Proceeding on the basis that its sole purpose was to develop generation outlet from Buffalo Ridge and not to improve overall system reliability or address projected load growth. MCEA maintained that the distinction was not determinative because renewable generation that complies with the conditions will be available to address load-serving and system reliability, as well as assure that

[520] T. 20 at 14 (Ellison).
[521] T. 20 at 15 (Ellison).
[522] T. 20 at 19-20 (Ellison).
[523] CETF Posthearing Brief at 50 *et seq*.)
[524] NAWO/ILSR Posthearing Brief at 36.
[525] Ex. 214, *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificates of Need for Four large High Voltage Transmission Line Projects in Southwestern Minnesota,* "Order Granting Certificates of Need Subject to Conditions," E-002/CN-01-1958, 03/11/03.

generation outlet is dedicated to renewable generation. MCEA agreed that wind generation is a variable resource, and when wind energy is not fully available, there will be non-firm capacity available to other resources.[526]

454. Although the MCEA may be correct that the conditions would not impede the ability of the CapX projects to meet the claimed need, the regulatory and political climate has changed significantly since the 825 MW Proceeding.

455. There is no basis to apply the conditions to the La Crosse Project because the Applicants have not claimed that it will increase generation outlet by a specified amount, except in coordination with the as-yet-unapproved RIGO lines.

456. Although the Applicants expect an increase of 350 MW on the Fargo Project, it will serve other identified needs, including improved regional and community reliability.

457. The Brookings Project is more similar to the Southwestern Minnesota 825 MW project upon which the Commission placed conditions. However, changes in the law and in MISO diminish the importance of placing any conditions upon its certificate of need.

458. Unlike Xcel Energy's claim in the 825 MW Proceeding, in this proceeding Applicants have not claimed that the CapX lines will serve renewable generation only. Here, Applicants' asserted need is to provide access to any form of generation to meet projected load growth.[527] OES has demonstrated that by 2020 Minnesota utilities will need 1,269 MW to 2,094 MW of non-renewable generation in addition to renewable generation. The CapX projects are a step toward serving that load growth.[528]

459. The regulatory environment has significantly changed since the Commission issued its order in the 825 MW Proceeding. Utilities are required to file IRPs demonstrating the generation resources that will be used to serve load, and the IRPs are reviewed for compliance with the recently enacted laws that include clear preferences for renewable generation and for generation that does not emit greenhouse gases. In that proceeding, the costs and benefits of resource selection are appropriately considered.

460. There are thousands of megawatts of wind generation seeking interconnection through MISO, including requests for interconnection at the substations along the Brookings Project. MCEA claimed that signed commitments are essential to get wind projects financed and constructed, but the length of the MISO queue suggests that wind development is booming as developers anticipate implementation of the states' renewable energy standards and possible carbon taxes. Regardless of whether the Applicants sign additional PPAs or commit to additional wind development, the experts testified that wind generation is the most likely form of generation to take up

[526] Ex. 206 at 5 (Ellison Surrebuttal); Ex. 199 at 7-9 (Schedin Surrebuttal).
[527] T. 13 at 116 (Alders).
[528] Ex. 274 at 1-2 (Ham Surrebuttal); Ex. 275.

new generation capacity. However, the Applicants have not convincingly demonstrated that the conditions would impede competitive bidding. There are multiple developers vying for interconnection.[529]

461. MCEA raised the possibility that, without conditions that tie the CapX projects to renewable energy, the Applicants may later claim that there is insufficient transmission to meet the RES milestones. The Commission may modify or delay the RES upon review of circumstances, including "transmission constraints preventing delivery of service."[530]

462. Minnesota transmission owners must regularly report on the transmission needed to meet the RES, which provides the Commission with the opportunity to monitor compliance, and minimizes the likelihood that the Applicants, or any Minnesota utility, can assert that there is insufficient transmission to meet the RES milestones. As previously cited, the recent report includes the Brookings Project and the Fargo Project among the transmission lines expected to support RES compliance.

463. Once the transmission lines are in place, the lowest-cost generation will be dispatched, regardless of the conditions placed on the Applicants. The integrated network system will operate in accordance with market security and economic dispatch. The conditions cannot extend to the actual operation of the transmission lines and its obligation to assure open and nondiscriminatory access.[531]

464. The Applicants and OES argued that transmission decisions should be independent of generation decisions, but they have relied in part upon the RES and MISO's lengthy list of wind generation interconnection requests as justification for the Brookings Project in particular, and the Fargo Project and La Crosse Project to a lesser extent. Nonetheless, this reliance does not logically lead to the conclusion that conditions should be placed on the CapX projects. The Applicants have a legal obligation to meet the RES, regardless of whether the CapX projects are approved or used,[532] and are on track to do so.[533] Even if the Applicants do not use the CapX projects to meet their own RES, there is demonstrated need for greater transmission facilities to meet forecasted load growth and to address the requests for interconnection on the MISO queue.

465. The proposed conditions are not appropriate to assure that the CapX projects address the demonstrated need for regional reliability, community reliability, or increased generation outlet.

---

[529] Ex. 204 at 4-5 (Ellison Direct).
[530] Minn. Stat. § 216B.1691, subd. 2b (7).
[531] MISO Reply Brief at 5-6; T. 5B at 55 (Webb).
[532] *See* T. 20 at 107 (Ellison).
[533] Ex. 54, 2007 Minnesota Biennial Transmission Projects Report, Part II (Renewable Energy Standards Report 2007) at Section 5. *See also,* Part 1 at 109 (Fargo Project), 183 (Brookings Project), 197 (La Crosse Project); Ex 231 at 26 (Peirce Direct) (Applicants in compliance with RES); T. 22 at 107 (Peirce).

C-BED Conditions

466. NAWO/ILSR proposed that the Commission condition the granting of the certificates of need on the Applicants' signing PPAs for 600 MW of dispersed C-BED projects within the next two years.[534] CETF proposed a similar condition: that the Commission condition the granting of the certificates of need on Applicants signing at least 300 MW of dispersed C-BED projects by 2012 if viable C-BED projects are available.[535]

467. NAWO/ILSR and CETF witnesses expressed a strong preference for C-BED. In their view, small, dispersed generation, particularly locally owned generation, provides the most benefit to the communities affected by generation and transmission development, and is most compatible with "[providing] benefits to society in a manner compatible with protecting the natural resources."[536]

468. Dr. Kildegaard's testimony focused on the benefits of small, community-owned energy development, including greater local job creation and spending.[537] He reviewed studies of the economic benefits of community based ownership and also participated in a study of data from Big Stone County on the economic impact of a locally-owned 10 MW wind project. The results of the study were consistent with the literature: community-owned wind projects have up to 5 times the economic impact on local value added and up to 3.4 times the impact on local job creation, relative to a project developed by an outside ownership group.[538]

469. Xcel Energy has announced its intention to deploy approximately 500 MW of C-BED by 2010, and has issued a request for proposal to fulfill this commitment.[539] Whether this is the appropriate amount of C-BED is best addressed in a resource planning docket where its costs and benefits can be analyzed.[540]

470. The Applicants acknowledge that there is a public interest in facilitating C-BED as part of the overall effort to develop renewable energy because C-BED offers greater opportunity for revenue to go into the communities.[541]

471. The DRG Study demonstrated that there are limited opportunities to add dispersed generation to the transmission system. The CapX projects may be able to increase the opportunity to add dispersed generation, but there is no evidence in this record of where or when those projects would be added or the cost of doing so, or whether community-based projects would or should take precedence over other forms of generation or ownership. Like the conditions proposed by MCEA, the preference to

---

[534] Ex. 115 at 4 (Michaud Surrebuttal).
[535] CETF Posthearing Brief at 76.
[536] Minn. R. 7849.0120, subp. C (2).
[537] Ex. 166 at 15-17 (Kildegaard Direct).
[538] Ex. 166 at 16-17 (Kildegaard Direct); Ex. 168, Kildegaard, Myers-Kuykindall, "Community vs. Corporate Wind: Does It Matter Who Develops the Wind in Big Stone County, Mn.?" revised, Sept. 2006.
[539] Ex. 132 at 25 (Alders); *see also,* Minn. Stat. § 216B.1691, subd. 10..
[540] Minn. Stat. §§ 216B.1612; 216B.1691, subd. 10; 216B.2422, subd. 2; Ex. 1 at 7.18-7.20 (Application).
[541] T. 13 at 107-108 (Alders).

be given to dispersed generation, and C-BED in particular, are better addressed in a resource planning docket where the relative costs and benefits can be fully examined.

Statutory Enactments That Affect the Determination of Need

472. Minnesota Statute § 216B.243, subd. 3 (10), requires the Applicants to demonstrate compliance with section 216B.2425, subdivision 7. Section 216B.2425, subdivision 7, requires utilities to determine the transmission upgrades needed to support the renewable energy standards under section 216B.1691. In their most recent biennial transmission plan, the Applicants and other utilities reported on current progress toward meeting RES and identified and discussed the transmission needed to meet the renewable energy objectives. The Fargo Project and the Brookings Project are among the lines that utilities project are needed to meet intermediate RES milestones.[542]

473. CETF contended that there is no direct connection between the CapX projects and the RES. It claimed that there were no specific identified wind projects that would interconnect to CapX and no assurance that any wind projects at all would interconnect.[543] However, the record is clear that wind energy is the most likely to connect to the Brookings Project, and that all three projects will relieve constrained transmission to allow for greater interconnection. So long as the Applicants can demonstrate that they are in compliance with the RES, the certificate of need statute does not limit use of the transmission lines use solely to renewable energy.

474. Minnesota Statutes § 216B.243, subd. 3 (12) states that the Commission shall evaluate:

> [I]f the applicant is proposing a nonrenewable generating plant, the applicant's assessment of the risk of environmental costs and regulation on that proposed facility over the expected useful life of the plant, including a proposed means of allocating costs association with that risk.

475. Similarly, Minn. Stat. § 216B.1694, subd. 2 (a)(5), applies to the building or construction of a fossil-fuel-fired generation facility.

476. Since the applicants are proposing transmission lines and not a nonrenewable generation plant, neither section 216B.243, subd. 3 (12), nor section 216B.1694, subd. 2 (a)(5) apply to this proceeding.

477. Minnesota Statute § 216B.243, subd. 3a, provides that the Commission may not issue a certificate of need for transmission that transmits electric power generated by a nonrenewable energy source. Section 216B.2422, subd. 4, includes a

---

[542] Ex. 54, 2007 Minnesota Biennial Transmission Projects Report, Part II (Renewable Energy Standards Report 2007) at Section 5. *See also,* Part 1 at 109 (Fargo Project), 183 (Brookings Project), 197 (La Crosse Project); Ex. 231 at 26 (Peirce Direct); Ex. 282 at 86-88 (Rakow Direct); (Applicants in compliance with RES).

[543] CETF Posthearing Brief at 26-27.

similar preference for renewable energy. These preferences have been interpreted to apply to transmission interconnecting to a specific generation source and not to transmission that improves the overall ability of the system, without regard to type of generation.[544] It is likely that the proposed CapX projects will enhance the development of renewable energy, but they are not intended to connect to any one generation source or type.

Minnesota Greenhouse Gas Emissions

478. In 2007, the Legislature enacted restrictions on greenhouse gas emissions. The law states, in part, that no party may import from outside the state power from a new large energy facility that would contribute to statewide power sector carbon dioxide emissions,[545] and it set goals for reduction of greenhouse gases.[546] NAWO/ILSR and CETF asserted that the CapX projects are inconsistent with the greenhouse gas emissions controls enacted in Minnesota and under discussion in other states.[547]

479. The CapX projects will not connect to a particular generator. In their IRP filings, the Applicants must specify their anticipated generation sources, and the Commission will have the opportunity to assess compliance with this statute.[548] Also, because of the current regulatory climate, as Dr. Rakow stated in his testimony, “the only generation it is reasonable to assume will be interconnected and delivered by the proposed transmission lines is generation that does not emit CO_2.”[549]

480. The incremental impact of the proposed projects will be significant reduction in line losses and the associated pollution, including greenhouse gases.

Evidentiary Support for the Findings of Fact

481. Citations to the transcripts or hearing exhibits in these Findings of Fact are not inclusive of all applicable evidentiary support in the record.

Based on these Findings of Fact, the Administrative Law Judge makes the following:

---

[544] Ex. 27, *In the Matter of the Application of Otter Tail Power Company for a Certificate of Need for Appleton-Canby 115 kV High Voltage Transmission Line,* Order Granting Certificate of Need, Docket No. E-017/CN-06-677 at 9 (April 18, 2007).
[545] Minn. Stat. § 216H.03, subd. 3.
[546] Minn. Stat. § 216H.02, subd. 1.
[547] NAWO/ILSR Posthearing Brief at 19-20.
[548] *See* Minn. Stat. § 216H.06.
[549] Ex. 303 at 30-31 (Rakow Rebuttal).

CONCLUSIONS

1. The Public Utilities Commission ("Commission") and the Administrative Law Judge have jurisdiction to consider the Applicant's Application for certificates of need for the La Crosse, Fargo and Brookings Projects.[550]

2. The La Crosse, Fargo and Brookings Projects each meet the definition of "large energy facility" and require a certificate of need from the Commission prior to construction.[551]

3. The Commission issued an Order Accepting the Certificate of Need Application as Substantially Complete, Contingent on Submission of Additional Data, on November 21, 2007.

4. Public hearings were held at places and times convenient to the public, and public testimony was taken at the public hearings, and through written comments.[552] Public hearings were completed on July 2, 2008; the evidentiary hearing was completed on September 18, 2008.[553] The Applicants' notice of the hearings complied with statute and rule. A Commission staff member was present at each hearing to facilitate public participation.[554]

5. Applicants have complied with all applicable procedural requirements for a Certificate of Need.

6. The criteria for evaluating the application for certificates of need are set forth in statute and rule.[555] Application of the criteria includes a determination of need and, based on the evidence in the record, whether there is a more reasonable and prudent alternative to address that need.[556]

7. Applicants bear the burden of proving the need for a proposed transmission line and demonstrating that the statutory criteria have been met.[557]

8. Applicants have demonstrated that there is a need for the La Crosse Project as proposed, for the Fargo Upsized Alternative, and for the Brookings Upsized Alternative. Each of the projects will address three needs: regional reliability, community reliability, and increased generation outlet.

9. No more reasonable and prudent alternative has been demonstrated to address those needs.

---

[550] Minn. Stat. §§ 216B.243 and 14.50.
[551] Minn. Stat. §§ 216B.243 and 216B.2421, subd. 2 (3).
[552] Minn. Stat. § 216B.243, subd. 4.
[553] Minn. R. 7829.1100; Minn. R. 7829.2500, subd. 9.
[554] Minn. Stat. § 216B.243, subd. 4; Notice and Order for Hearing, Nov. 21, 2007.
[555] Minn. Stat. § 216B.243, subd. 3; Minn. R. 7849.0120.
[556] *See, e.g.* Minn. R. 7849.0120 B.
[557] Minn. Stat. § 216B.243, subd. 3.

10. The La Crosse Project as proposed, outlined on Attachments C and D, has two configurations. Selection should be subject to a determination in the routing proceeding of the most appropriate river crossing and substation termination.

11. The in-service date for the Northern Hills-North Rochester 161 kV line shall be the third quarter of 2011, subject to modification in the course of proceedings addressing the certificates of need for the RIGO projects.

12. Applicants have demonstrated the need for the North Rochester-Chester 161 kV line or, in the alternative, a direct connection of the 345 kV line at the Chester Substation, if dictated by selection of the Southern Crossing in the routing proceeding.

13. The Fargo Upsized Alternative, as outlined on Attachment A, is the best configuration, subject to a determination in the routing proceeding of the most appropriate northwestern termination.

14. The Brookings Upsized Alternative, as outlined on Attachment B, is the best configuration, subject to confirmation of the most appropriate eastern termination.

15. The Commission must fully examine the option of generating power by means of renewable energy sources, including hydro, wind, solar, and geothermal energy and the use of trees or other vegetation as fuel.[558] The proposed transmission lines are likely to carry electric power generated by both renewable and nonrenewable energy sources. The Applicants have demonstrated that the transmission lines cannot be replaced by renewable energy sources.

16. Applicants must show that a renewable energy facility is not in the public interest. Applicants have shown that renewable energy facilities cannot meet the demonstrated need for additional transmission to provide regional and community reliability and increased generation outlet capacity.[559] Applicants have demonstrated that granting the certificates of need for CapX is in the public interest and has a high probability of promoting increased renewable energy generation.

17. The Environmental Report was filed as required, its contents met the criteria set forth in rule, and it complied with the Scoping Order.[560] Each corridor has at least one feasible route with feasible river crossings that, with proper mitigation, will not significantly degrade the natural environment. The CapX projects will have a substantial impact on the natural environment. Routing and construction should be conducted to avoid harmful effects and, where damage is unavoidable, to significantly mitigate the impact.

[558] Minn. Stat. § 216B.243, subd. 3a.
[559] *See* Minn. Stat. §216B.2422, subd. 4.
[560] Minn. R. 7849.7060, subps. 1, and 3; Minn. R. 7849.7090.

18. Applicants have demonstrated that they are in compliance with the RES set forth in Minn. Stat. § 216B.1691.[561]

19. Applicants have satisfied other relevant statutory criteria set forth in Minn. Stat. § 216B.2422, subd. 4 (renewable energy preference), Minn. Stat. § 216B.2426 (distributed generation), Minn. Stat. § 216B.1612 (C-BED), and Minn. Stat. § 216H.03 (greenhouse gas emissions).

20. Applicants shall provide a compliance filing, informing the Commission and other interested parties of the final ownership interest of all sponsoring utilities, once ownership arrangements have been finalized.

21. Applicants shall take those actions necessary to implement the Commission's orders in this proceeding.

22. Any of the Findings of Fact more properly designated Conclusions are hereby adopted as such.

Based upon these Conclusions, and for the reasons explained in the accompanying Memorandum, the Administrative Law Judge makes the following:

RECOMMENDATIONS

1. That the Commission approve the La Crosse Project as proposed, subject to the following:

   a. The final decision concerning the location of the Mississippi River crossing and the termination point near La Crosse shall be made in the routing proceeding;

   b. Approve the third quarter of 2011 as the in-service date for the Northern Hills-North Rochester 161 kV line, subject to modification in the course of proceedings addressing the certificates of need for the RIGO projects; and

   c. Approve the North Rochester-Chester 161 kV line or, in the alternative, a direct connection of the 345 kV line at the Chester Substation, if dictated by selection of the Southern Crossing in the routing proceeding.

2. That the Commission approve the Fargo Upsized Alternative, subject to the following: The decision whether the northwestern termination should be at the Maple River Substation or at a new substation near Fargo, North Dakota, shall be determined in the routing proceeding, with due regard for the authority of the North Dakota Public Service Commission.

---

[561] *See* Ex. 54*;* Ex. 231 at 26 (Peirce Direct); Ex. 282 at 86-88 (Rakow Direct).

3. That the Commission approve the Brookings Upsized Alternative, subject to the following: The decision whether the eastern termination should be at the Lake Marion Substation or the Hampton Corners Substation cannot be made on this record. The Commission may request that the Applicants explain why the new substation was included in the supporting studies, and its benefits to regional reliability, community load serving, and generation outlet.

Dated: February 27, 2009

s/Beverly Jones Heydinger

BEVERLY JONES HEYDINGER
Administrative Law Judge

Reported: Transcripts Prepared

NOTICE

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Minnesota Public Utilities Commission ("Commission") and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed according to the schedule which the Commission will announce. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions and Order should be included, and copies thereof shall be served upon all parties. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument. Such request must accompany the filed exceptions or reply (if any), and an original and 15 copies of each document should be filed with the Commission.

The Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that the recommendation has no legal effect unless expressly adopted by the Commission as its final order.

MEMORANDUM

The Applicants have proposed an ambitious project to upgrade the transmission system so that it will serve the state for many years. Many of the benefits of the proposed projects are dependent on future development. Although this makes the Application more difficult to evaluate and vulnerable to criticism, it is also one of its strengths. New transmission lines stretching for miles across the open land will have a negative impact on the environment.[562] Thus, it is essential to determine if there is a demonstrated need for the transmission lines, and if there is, to evaluate any reasonable, prudent alternative.

The Applicants have demonstrated that the CapX projects meet three needs: to improve the regional reliability of the transmission system, to improve community reliability in specified communities, and to increase generation outlet. For regional reliability, all of the documented load forecasts demonstrate that the need for reliable electricity will continue to grow through 2020. Although the economy is currently in recession, the modeling took into account a "slow-growth" forecast that was approximately 30 percent lower than the expected growth. This is a substantial reduction. Also, OES recalculated the forecasted load, taking into account the newly enacted conservation standards. Its analysis showed that the estimated 2009 load that served as the basis for earlier projections was low, but also used other forecast methods to verify that the load levels included in the Applicants' models were well-supported. Thus, even with slowed growth in demand, the level of load used in the transmission studies was amply justified.

For their estimates of community reliability, the Applicants reduced the forecasted growth rate below historical levels. Its analysis showed that the load in the identified communities would exceed the level at which the system could provide reliable service by about 2011. OES also verified the community load projections.

NAWO/ILSR and CETF asserted that the community needs could be met by greater conservation and demand management. However, they could provide no experience-based data that supported a revised load forecast. They also claimed that local generation or dispersed generation could reliably service local needs. But they failed to offer concrete evidence of the location, size, and cost for such projects and whether additional transmission would be needed to add new generation to the system. Moreover, the DRG Study, rather than supporting the claim that dispersed generation is a viable substitute, demonstrated that there are limited opportunities to add dispersed generation to the transmission system. To do so, the study removed generation from the system and found that there were significant areas where siting dispersed generation was very difficult. Those areas included wind-rich portions of western Minnesota.

MCEA, NAWO/ILSR, NoCapX, UCAN and CETF support the public policy of shifting to renewable forms of energy, and specifically support further development of wind power. Their contention is that the CapX projects may support non-renewable generation rather than bolster the shift to renewable resources. However, federal law requires open access to transmission lines, and neither the Applicants nor MISO can guarantee that only renewable forms of energy will have access to the CapX projects. The Applicants and MISO are obliged to maintain an adequate supply of transmission

---

[562] *Accord, People for Environmental Enlightenment and Responsibility (PEER) v. Environmental Quality Council,* 266 N.W.2d 858,867 (Minn. 1978).

capacity to serve generators requesting transmission service and to assure reliable, secure service to customers. It takes several years to study, plan, seek approval, and construct new transmission lines. By placing large transmission lines into areas where new generation is likely, the Applicants will strengthen the backbone of the transmission system and support new interconnection. In this case, the number of wind projects on the MISO queue is ample evidence of potential renewable generation in the area that the CapX projects will serve.

Although there are no guarantees that only renewable generation will be added to the system, there are a number of legislative mandates that increase the likelihood that the greatest portion of the new additions will be renewable generation. The Applicants, MISO and OES all predicted that renewable generation will take most, if not all, of the capacity added by the CapX projects because of the RES and limitations on carbon emissions.

Policies promoting conservation and renewable energy are within the purview of the legislature and subject to the Commission's oversight. Those bodies are best suited to evaluate the full picture of costs, benefits, and overall compliance. A certificate of need proceeding for transmission lines with no direct connection to a specific generator is not the appropriate forum in which to weigh the larger societal costs and benefits of the shift away from fossil fuels toward renewable energy. The Applicants and OES applied the conservation and renewable energy standards that are currently in place and guide Minnesota resource planning. Holding the Applicants to standards that exceed those set by the Legislature is not warranted in a certificate of need proceeding.

The Applicants have demonstrated that the need for the Fargo Upsized Alternative and Brookings Upsized Alternative is near-term, from the perspective of transmission planners. Planning is well underway to upgrade the major limiter to increasing capacity on both of these projects, the Minnesota Valley-Blue Lake 230 kV line. The application for a certificate of need to upgrade it is imminent, and perhaps already initiated. The Applicants' revised proposal to upgrade the Lyon County-Minnesota Valley line as part of the Brookings Project reflects this probability. OES estimated that the amount of new generation needed to meet the RES exceeds 3000 MW. The Upsized Alternative for the Brookings and Fargo Projects provides a cost-effective alternative for gaining access to the wind-rich portions of Minnesota, North Dakota and South Dakota.

In contrast, there was no compelling evidence to support the Upsized Alternative for the La Crosse Project. Although there were general statements that constructing larger structures is common-place in some parts of the country, and at some point a second circuit could provide greater access to the east and south or back up renewable energy, there was no specific evidence of any projects under consideration that would benefit from the Upsized Alternative, or transmission constraints beyond those that would be addressed by the La Crosse Project as proposed and the RIGO lines. In fact, the record was clear that the La Crosse Project as proposed would serve community needs, enhance regional reliability, and support renewable generation well past 2020.

Because of the rapid pace of change in policies to reduce use of fossil fuels, to develop more demand-side management with Smart Grid and other innovations, and to promote more dispersed generation and community-based energy development, it is very difficult to predict whether the Upsized Alternative for the La Crosse Project will be required to meet need beyond 2020.

Nonetheless, there may be significant environmental benefits to constructing larger towers in some locations. During the siting, the quantity of power transfer and type of transmission lines may not be reconsidered, but the relative costs and benefits of installing larger structures in selected locations can be evaluated.

Some of the parties and members of the public are certain that the proposed projects, and especially the Upsized Alternative, are a subterfuge to speed development of transfer of power from the western states of North and South Dakota to load in Wisconsin and points further to the west. The record does not support this fear. Each of the planning engineers credibly testified that the lines are intended to strengthen regional reliability to serve Minnesota load by providing alternative paths to the metropolitan area and the identified communities, reducing current congestion, and helping Minnesota meet its renewable energy goals.

CETF, NAWO/ILSR and NoCapX were critical of contingency planning that addressed the loss of a second facility, either a generator or a transmission line. However, the NERC standards require the planners to identify the problems created by a second outage and prepare back-up for that second contingency. There was no basis to conclude that such planning was unnecessary or excessive.

It is inevitable in a proceeding of this size and complexity that some points are not fully addressed to the satisfaction of the Administrative Law Judge. One of those was raised by CETF. The underlying studies that led to the development of the Brookings Project included the new Hampton Corners Substation as the eastern endpoint. However, review of the record identified no explanation for extending the project from the Lake Marion Substation to Hampton Corners. In order to assure that the additional miles of transmission line are fully explained, the Commission may ask the Applicants to provide a basis for including the new substation in the studies and its benefits to regional reliability, community load serving and generation outlet.

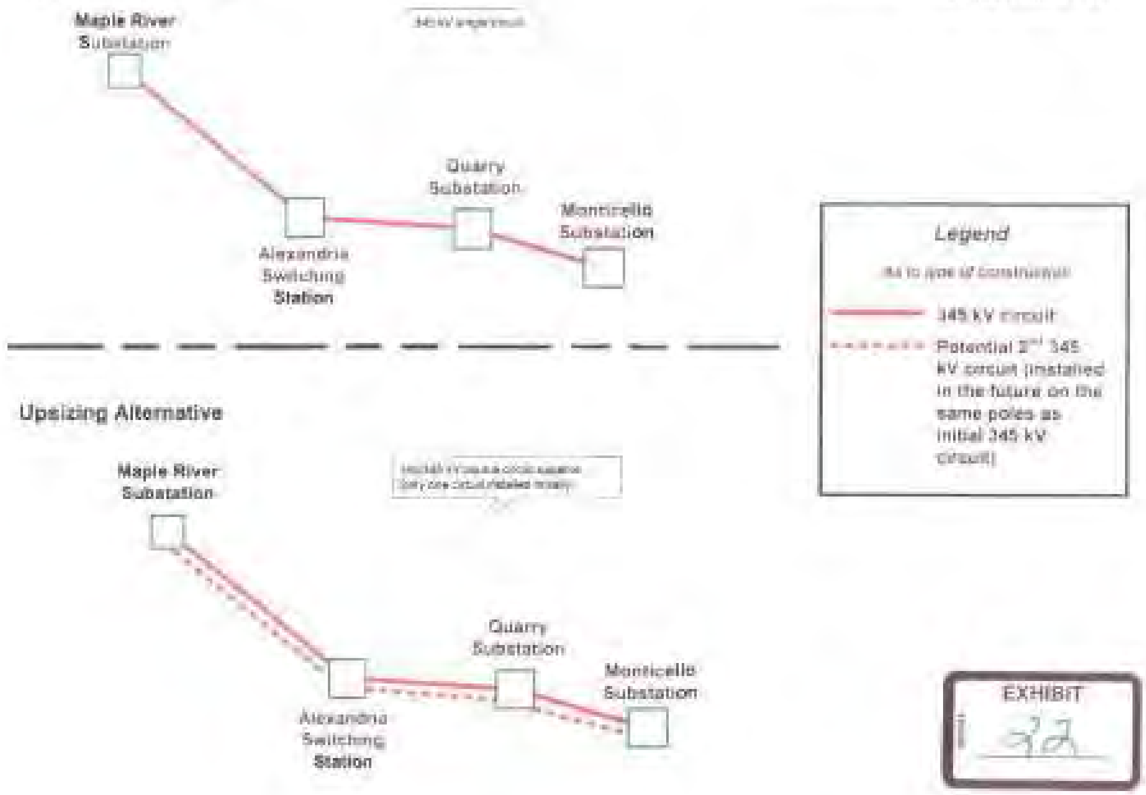
Although the positions taken in this proceeding by MCEA, NAWO/ILSR and CETF did not ultimately prevail, their importance to the proceeding cannot be overstated. Each of them carefully analyzed the Application and its supporting documents. Each of them asked for explanations and clarification that improved the quality of the record, pointed out errors and inconsistencies, and enhanced the deliberation. They served the public well by contributing to a more transparent, open process. Their involvement required significant investment of both time and money and, unlike in utility rate proceedings, they participated without the possibility of reimbursement.[563] They are commended for their commitment to serving the public interest.

B. J. H.

[563] *See* Minn. Stat. § 216B.16, subd. 10.

CapX2020: Twin Cities – Fargo 345 kV Project

Docket No. E-002/CN-06-1115
OAH Docket No. 15-2500-19350-2
ATTACHMENT A



CapX2020: Twin Cities – Brookings County 345 kV Project

Application Proposal

Docket No: E-002/CN-06-1115
OAH Docket No. 15-2500-19350-2
ATTACHMENT B

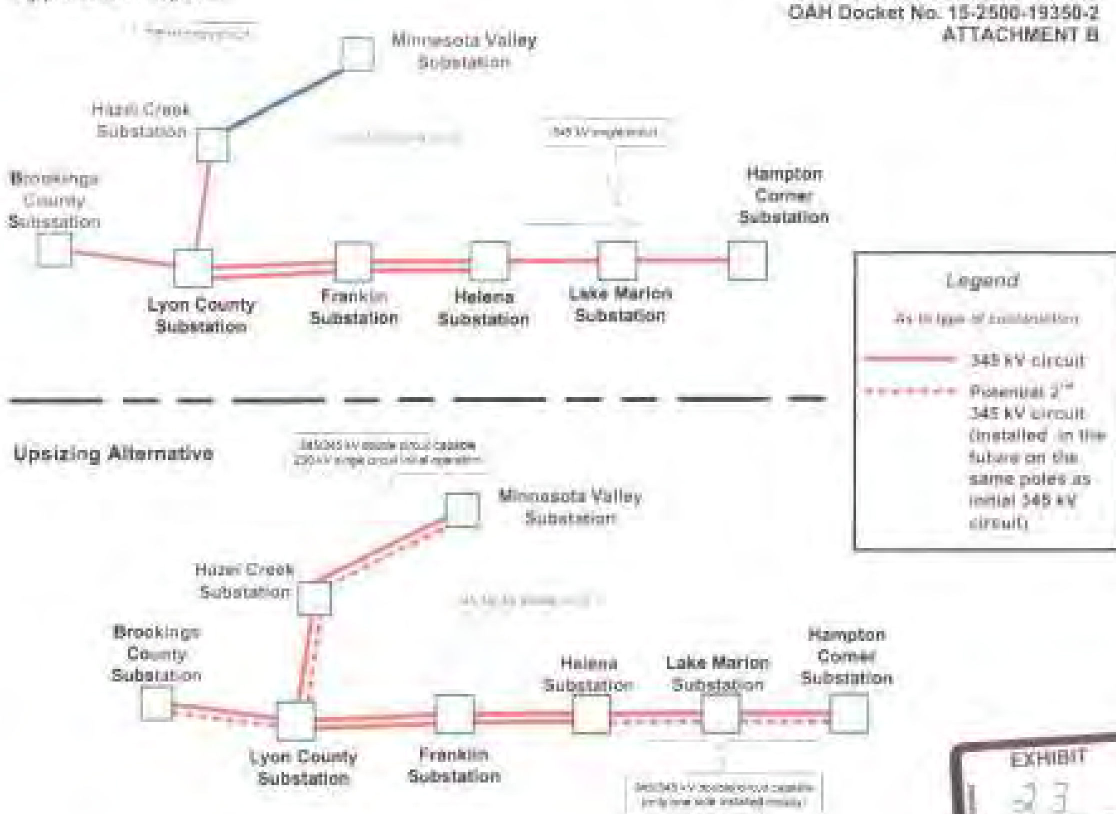


EXHIBIT
23

CapX2020: Twin Cities – La Crosse 345 kV Project – *Southern Crossing*

Application Configuration (as amended in Stevenson direct testimony)

Docket No. E-002/CN-06-1115
OAH Docket No. 15-2500-19350-2
ATTACHMENT C

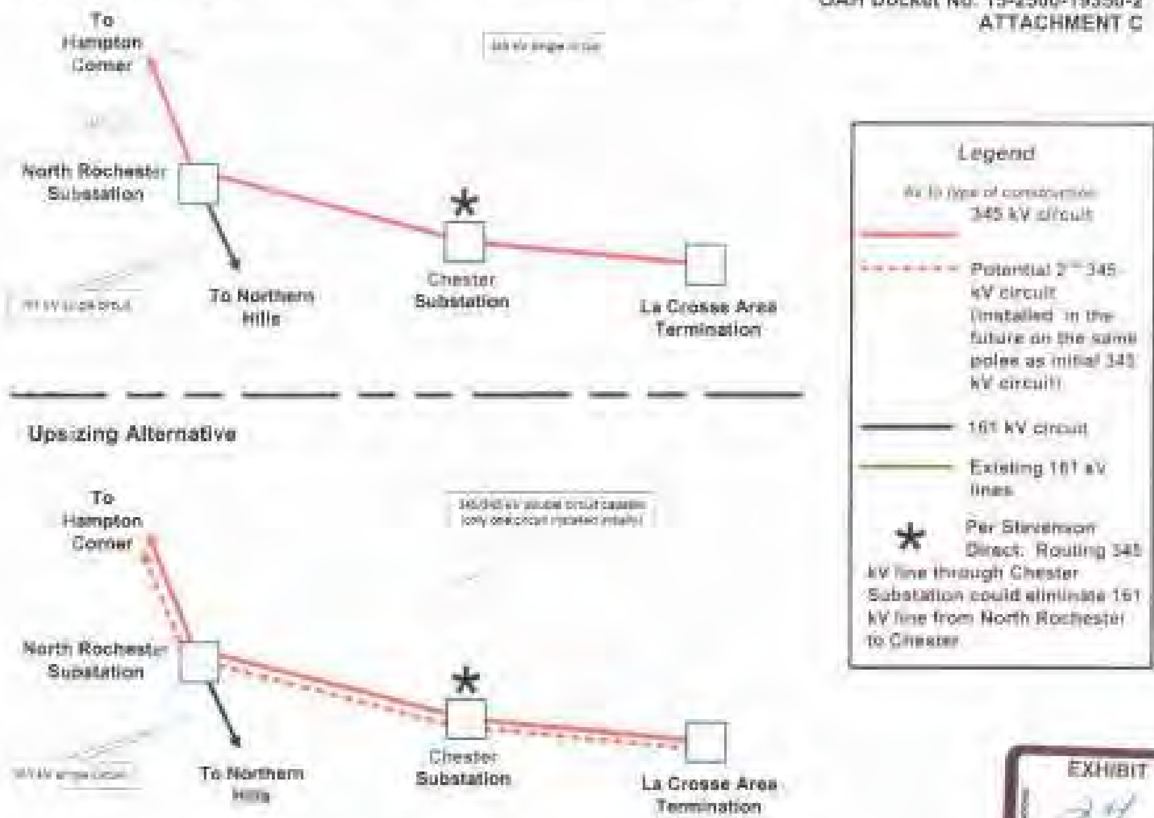
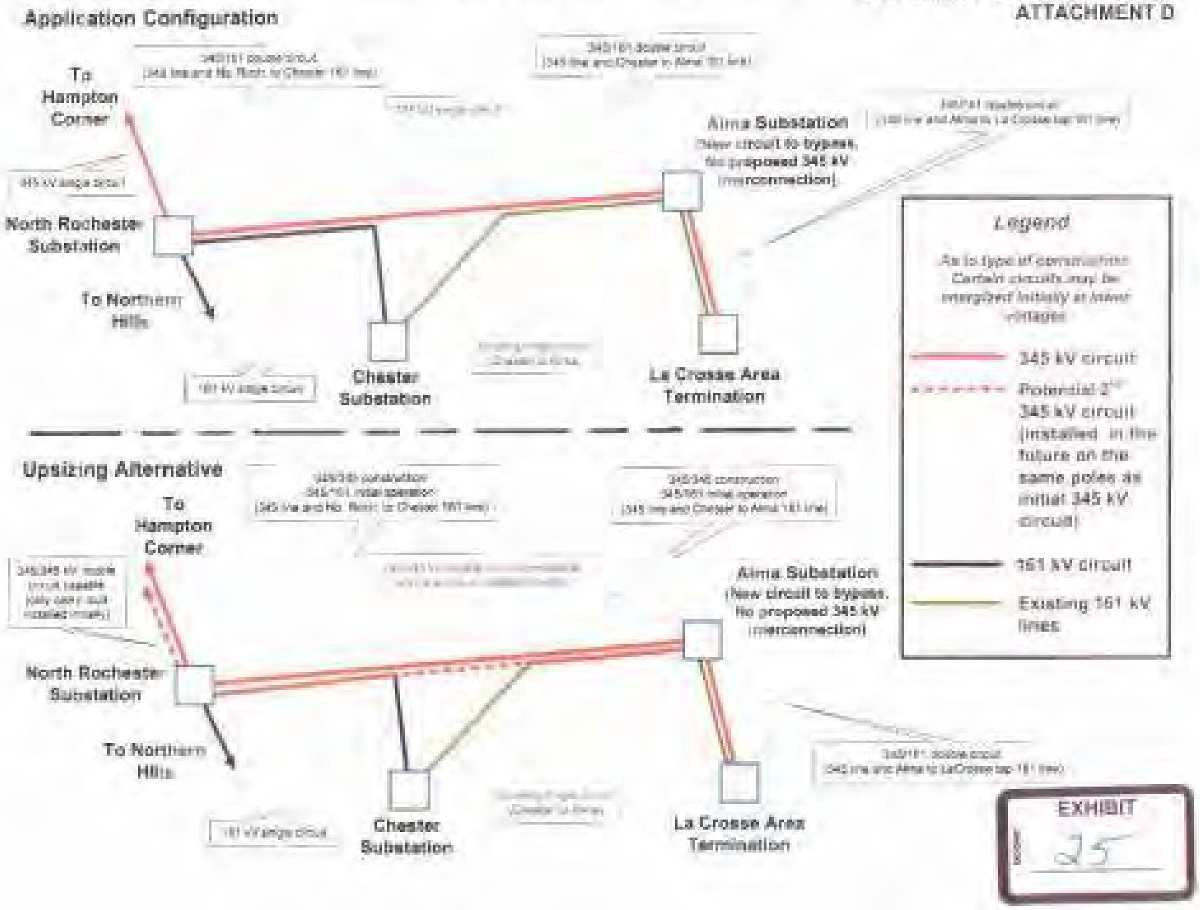


EXHIBIT
34

CapX2020: Twin Cities to La Crosse 345 kV Project – *Alma Crossing*

Docket No. E-002/CN-06-1115
OAH Docket No. 15-2500-19350-2
ATTACHMENT D



Revised Figure 6-6*, Load Growth Forecasts

PUC Docket No. E002/CN-06-1115
OAH Docket No. 15-2500-19350-2
Attachment E

Forecast Source	Citation	Forecast Scenario	Load Forecast (MW)		Load Growth by 2020 (MW)
			2009	2020	
CapX2020 Vision Plan	Ex. 6 at 15 (Rogelstad Direct)	Expected Growth	20,201	26,488	6,287
	Ex. 48 at 8-9 (Lacey Direct)	Slow Growth**	20,201	24,701	4,500
MAPP Load and Capability	Application Figure 6-6	System Demand	20,783	25,969	5,186
Integrated Resource Plans	Ex. 48 at 8 (Lacey Direct)	High	22,488	27,392	4,904
		Median	21,332	25,427	4,095
IRP per NAWO IR No. 7*** (Ex. 51)	Ex. 140 at 4 (Michaud Direct)	High	22,938	27,708	4,789
		Medium	21,789	25,708	3,919
OES Analysis	Ex. 257 at 15 (Ham Direct)	Base Case	22,228	27,060	4,832+
	Ex. 247 at 4 (Peirce Surrebuttal); Ex. 215 at 12-13 (Davis Direct)	Revised w/1.0% DSM		26,357	4,129
		Revised w/1.5% DSM		25,690	3,462
	Ex. 274 at 2 (Ham Surrebuttal)	Revised w/new generation to meet RES			4,621-6,817[1]

* Revised version of Ex. 53.

** This is a planning assumption of 30% lower than the expected growth level. Ex. 48 at 5 (Lacey Direct).

*** Based on Lacey's response to NAWO IR No. 7 (Ex. 51) – taking into account the three new IRPs that also include consideration of the 1.5% conservation statute. Dairyland's IRP appears not to have taken the 1.5% conservation statute into consideration.

\+ Mr. Ham assessed the need for 4,688 – 6,880 MW of new generation by 2020 to meet overall customer usage by 2020, including 1,349 – 2,173 MW of non-renewable energy generation and 3,148 – 4,911 of new wind to meet state RES. Ex. 231 at 21 (Peirce Direct).

[1] Mr. Ham revised the OES forecast of additional generation. Includes 1,269-2,094 of non-renewable and 3,160-4,927 of renewable generation. Ex. 275.

ESTIMATED PROJECT COST

PUC Docket No. E002/CN-06-115
OAH Docket No. 15-2500-19350-2
Attachment F

PROJECT	APPROXIMATE COST, In Millions, as Proposed	APPROXIMATE COST, In Millions, Upsized Alternative
La Crosse Project[564]	$364 - $374 (Alma Crossing) $355 - $363 (Southern Crossing)	$389 - $415 (Alma Crossing) $407 - $432 (Southern Crossing)
Fargo Project[565]	$390 - $560	$500 - $640
Brookings Project[566]	$603.7 - $669.6	$654 - $725
Underlying System Improvements[567]	$70 - $100	$70 - $100

[564] Ex. 89 at 4 (Stevenson Surrebuttal).
[565] Ex. 83 at 16 (Stevenson Direct); Ex. 88 at 5 (Stevenson Rebuttal), Excludes new Fargo-area substation cost of approximately $20 million; Ex. 312 (Kline Final Rebuttal).
[566] Ex. 116 at 9 (Lennon Direct); Ex. 120 at 4-5 (Lennon Rebuttal).
[567] Ex. 1 at 2.17 (Application).

Attachment C

Safe Separation Distances from Natural Gas Transmission Pipelines

Safe Separation Distances From Natural Gas Transmission Pipelines

**James S. Haklar, Ph.D., P.E.
and Robert Dresnack, Ph.D., P.E.
New Jersey Institute of Technology
Newark, N.J.**

Abstract

Accidental rupture of natural gas transmission pipelines with subsequent ignition of the escaping gas can result in the loss of life and property. A method for evaluating distances at which the pipelines can be safely set back from the community, called safe separation distances, is proposed herein, in which the point source method for determining heat flux is coupled with relationships for predicting both the mass release rate from the rupture and the flame height of the ignited gas. The method is utilized to develop charts for predicting safe separation distances based on pipeline operating pressure and nominal pipeline diameter.

Introduction

Increased development of formerly sparsely populated areas has resulted in instances of encroachment of natural gas transmission pipeline rights-of-way (ROWs). Accidental ruptures of these pipelines with subsequent ignition of the escaping gas can result in the loss of life and property near these lines. A description of the effects of such accidents can be found in the pipeline accident reports prepared by the National Transportation Safety Board (NTSB), the independent Federal agency that investigates pipeline accidents occurring in the United States.

One example of the destructive effects of pipeline ruptures was the explosion, in Edison, New Jersey, of a 36-inch pipeline operating at a pressure of 970 psig. This accident occurred on March 23, 1994 and severely affected a nearby apartment complex. The apartment complex sustained $12.4 million in damages, which included the loss of eight apartment buildings, severe damage to six buildings and minor damage to several other building (NTSB, 1995). This accident served as the basis for the evaluation, described in this paper, of the proximity at which pipelines can be safely sited near a community. These distances are called "safe separation distances."

In general, both the United States and foreign countries address the establishment of separation distances either directly, or indirectly through the designation of various location or population classes. In those instances where a defined allowable ROW has been established, the width of the ROW from the pipe centerline is relatively small (less than 100 feet) and is generally intended to protect the pipe rather than the public. Separation distances have also been developed by some countries based on the concept of risk assessment. This paper describes the development of a methodology to estimate actual separation distances required, based upon the effects of a rupture of a natural gas transmission pipeline of a specified diameter and operating pressure. The methodology is developed, in part, with data collected from prior investigations of actual natural gas transmission pipeline accidents.

Literature Review

The purpose of the literature review was to gain an understanding of prior research concerning both natural gas pipeline accidents and the determination of safe separation distances from natural gas transmission pipelines. Activities associated with the literature review included review of NTSB files and Commodity Pipeline Occurrence Reports prepared by the Canadian Transportation Safety Board (TSB). Other activities consisted of discussions of the issue of safe separation distances with the European Gas Pipeline Incident Data Group located in the Netherlands, the NTSB, the Canadian TSB, the Canadian National Energy Board, the United States Environmental Protection Agency, the American Gas Association, the Research and Special Programs Administration, the Gas Research Institute, and the Township of Edison. Finally, various texts and technical journals of the oil and gas pipeline industry were reviewed pertaining to pipelines, hazard assessment, heat transfer and fluid flow.

In general, the literature review revealed that there has been limited studies to date concerning the determination of safety separation distances. The prior research reviewed is predominantly concerned with predicting the loss of product during an actual pipeline rupture (i.e., blowdown), rather than directed to concerns associated with establishment of adequate safe separation distances for the public.

The modelling of product loss during a pipeline rupture, which is an important factor related to the establishment of a safe separation distance therefrom, is, as indicated in a number of research papers reviewed, difficult to simulate. This is due to disparity amongst researchers as to the conditions under which the blowdown is modelled (e.g., adiabatic or isothermal; whether the fluid is viscous or nonviscous, etc.).

The literature review also revealed that the available database of information associated with actual natural gas pipeline accident occurrences in the United States and Canada is limited. For example, the pipeline accident reports (PARs) prepared by the NTSB do not consistently report parameters such as the total volume of gas lost in an accident, or the location of the closest valves upstream and downstream of the pipeline rupture. Furthermore, supporting information for the more dated PARs (in the PAR dockets in Washington, DC) is periodically destroyed. The Commodity Pipeline Occurrence Reports prepared by the Canadian TSB are similar to the PARs in that there are also inconsistencies in the extent of information contained in these reports.

Because of the aforementioned reasons, it was concluded that an approach to advance the state-of-the-art in the discipline of pipeline risk analysis is to develop a reliable estimation technique to conservatively predict safe separation distances to be articulated between the public and the ruptured natural gas pipeline.

Methodology

The simplified approach for estimating safe separation distances was developed based upon assumptions that the damage from a pipeline rupture is primarily due to the thermal radiation produced by the ignited gas behaving like a vertical jet flame. The thermal radiation will produce an impact area, the extent of which can be determined through the estimation of a "burn radius". The major variables associated with the burn radius resulting from a pipeline rupture are the size of the pipeline and its operating pressure (which directly affects the mass flow rate in the pipeline). The appropriateness of this approach in providing results of an accuracy suitable for regulatory agencies to utilize for establishing zoning guidelines was confirmed by comparing results from the aforementioned model with actual burn radii found in a limited number of accident investigations conducted by the NTSB in which sufficient data was obtained to verify the subject model herein.

As indicated above, an assumption is made that the damage from a pipeline rupture is primarily due to the thermal radiation produced by the ignited gas. Therefore, a safe separation distance is defined as the distance beyond which a pre-established level of thermal radiation damage will not likely occur. Other damage (such as projectile damage from pipeline fragments or damage due to over pressures from explosions) is not considered. This assumption is consistent with the results from investigations of actual pipeline ruptures, in which damage was found to be caused primarily from the fire. Therefore, the safe separation distance from a pipeline can be defined in terms of the distance needed to protect against a specified heat flux. This specified heat flux will produce an area of thermal radiation damage in the vicinity of the pipeline which can be estimated by calculating the burn radius.

Use of the Point Source Method

The point source method forms the basis for the estimation of safe separation distances. The following equation is presented from the work of Oenbring and Sifferman (1980):

$$K = FQ/(4\pi D^2) \qquad (1)$$

where K = radiation heat flux from a flame (Btu/hr ft^2); F = fraction of total heat radiated; Q = total heat content of the flared gas (Btu/hr); and D = distance from point source to receptor (ft).

Those authors provide the source for Equation (1) as being the American Petroleum Institute (API) document API RP-521. In a later version of this document (API, 1990), API provides the revised equation:

$$D = (\tau FQ/(4\pi K))^{1/2} \quad (2)$$

where τ = the fraction of thermal radiation transmitted through the atmosphere.

Application of the point source method is shown in Figure 1, where ignition of escaping gas from a pipeline rupture results in a flame of height "H". The point source is placed in the center of the flame at H/2, and the burn radius (BR) is found from the Pythagorean Theorem:

$$BR = \{D^2 - (H/2)^2\}^{1/2} \quad (3)$$

By inserting Equation 2 into Equation 3, the following relationship is obtained:

$$BR = \{(\tau FQ/(4\pi K)) - (H/2)^2\}^{1/2} \quad (4)$$

This is the basic form of the burn radius equation. The burn radius is function of the transmissivity of the thermal radiation through the atmosphere, the fraction of total heat radiated, the heat content of the escaping gas, the specified heat flux (or level of damage), and the flame height.

Based on information provided by various researchers for methane (NFPA, 1988), the value of F can be reasonably estimated to be 0.2. Calculation of the transmissivity of thermal radiation through the atmosphere was performed using the method of Brzustowsi and Sommer (1973), as discussed by API (API. 1990). By assuming a relative humidity of 50% and a distance to the flame of 500 feet (both of which are reasonable values for pipeline accident scenarios), the atmospheric transmissivity is determined to be 0.746. Inserting the values of τ and F into Equation 4, the equation for the burn radius becomes:

$$BR = \{(0.011873Q/K) - (H/2)^2\}^{1/2} \quad (5)$$

The total heat content of the escaping gas (Q) in Btu/hr can be found by multiplying the heat content of natural gas (1,000 Btu/scf) by the volumetric flow rate of the escaping gas (scf/hr):

$$Q = 1{,}000(V') \quad (6)$$

where V′ = volumetric flow rate (scf/hr). If Equation 6 is inserted into Equation 5, the expression for the burn radius becomes:

$$BR = \{(11.873(V')/K - (H/S)^2\}^{1/2} \quad (7)$$

Determination of Gas Flow Rate

The volumetric flowrate of the escaping gas, V′, can be found using a modified form of an equation, found in the Pipe Line Rules of Thumb Handbook, (McAllister, 1993), which is used when calculating the volume of gas lost through a puncture or blowdown. This equation is expressed as:

$$Q = D^2 P_1 \quad (8)$$

where: Q = volume of gas in Mcf/hr at a

pressure of 14.9 psi, 60°F with a specific gravity of 0.60; D = diameter of the nipple or orifice in inches; and P_1 = absolute pressure in psi at some nearby point upstream from the opening.

Equation 8 is modified by examining the rates of gas lost through actual pipeline ruptures (see Table 1) and comparing these rates with values obtained using the equation. Based on this evaluation, Equation 8 was modified to be:

$$V' = (1,000)(0.34)D^2P \qquad (9)$$

where V′ = gas flow rate, scf/hr; D = pipeline diameter, inches; and P = incident operating pressure, psia. It should be noted that multiplication by 1,000 in Equation 9 converts Mcf/hr to scf/hr. Equation 9 reflects the fact that insertion of the maximum initial flow rate into the point source equation will not accurately reflect thermal radiation conditions, since the heat flux at a given receptor location will decrease with the decreasing gas flow. Therefore, V′ can be considered to be a representative gas flow rate.

Determination of Flame Height

In a manner similar to the method for determining the expression for gas flow rate, the information obtained from actual pipeline accidents can be used to estimate flame height. Hawthrome, Weddell and Hottell (1949) developed an equation that, for a given gas, expressed the flame length as being directly proportional to the jet (or nozzle) diameter. This observation can be applied to the NTSB pipeline accident data of Table 2, where estimation of flame heights are provided. If the assumption is made that the jet diameter is equal to the pipeline diameter for a full bore rupture, the following relationship is obtained:

$$\begin{aligned} H &= 147(D/12) \\ &= 12.25(D) \qquad (10) \end{aligned}$$

where D = pipeline diameter (in).

By inserting Equation 9 and Equation 10 into Equation 7, the final burn radius equation is found:

$$BR = D\{(4,036.82)P/K - 37.52\}^{1/2} \qquad (11)$$

where BR = burn radius (ft); D = pipeline diameter (in); P = incident operating pressure (psia); and K = heat flux (Btu/hr ft^2).

Equation 11 provides a means by which the burn radius (and hence the safe separation distance) can be found knowing only the pipeline diameter, incident operating pressure and the level of damage (i.e., heat flux) to be considered. Since pipeline operating pressures are typically specified as gauge pressures, Equation 11 can be modified for application to gauge pressures by substituting the quantity (P′ + 14.7) for P, where P′ is the incident operating pressure in psig.

Heat Flux Values

Several examples of heat flux values corresponding to specific consequences are provided in Table 3. These values were obtained from a review of the literature.

From these heat flux values, it can be seen that the level of thermal radiation damage may not only depend on the intensity of the heat flux, but also on the length of time that the receptor is receiving that heat flux. For example, at a heat flux intensity of 9,985 Btu/hr ft², spontaneous ignition of wooden building occurs *after a few minutes.* Similarly, the maximum tolerable heat flux for *short-term* exposure for people is 2,000 Btu/hr ft². Therefore, a safe separation distance is considered to afford protection from a certain level of heat flux for a specific time period. If that time period is exceeded, damage may occur.

In order to estimate a safe separation distance, a level of protection is chosen, such as protecting wooden buildings from spontaneous ignition for a few minutes. The corresponding heat flux is found and inserted into Equation 11 as the appropriate K-value.

Construction of Charts to Predict Safe Separation Distances

The following procedure is used to construct charts for the estimation of safe separation distances. The first step involves deciding the degree of thermal radiation damage to consider. For example, the damage might be spontaneous ignition of wooden buildings after a few minutes exposure to the ignited gas. Protection for a few minutes may allow enough time for emergency responders to arrive at the scene and initiate protective measures (such as watering down the building). Based on the information provided in Table 3, the heat flux corresponding to the specified level of damage is 9,985 Btu/hr ft². This value is inserted into Equation 11 for K:

$$BR = D\{(4{,}036.82)P/9{,}985) - 37.52\}^{1/2} \quad (12)$$

Equation 12 is an expression of the burn radius as a function of only diameter and incident operating pressure. For various pipeline diameters, charts are then constructed of the burn radius (on the y-axis) and the incident operating pressure (on the x-axis). In the example, a pipeline diameter of 36" can be used with incident operating pressures in the range of 575 psia to 1,200 psia to construct a chart similar to the one shown in Figure 2. Once the chart is completed, it can be used either to determine a safe separation distance given a specified incident operating pressure, or to determine the incident operating pressure required to maintain a specified safe separation distance.

Charts for estimating safe separation distances (or burn radii) were developed for heat flux values of 3,962 Btu/hr ft² (piloted ignition of wood); 6,340 Btu/hr ft² (blistering of bare skin in 4 seconds and 1 percent lethality in 20 seconds); 9,510 Btu/hr ft² (causes third degree burns in 30 seconds); and 9,985 Btu/hr ft² (spontaneous ignition of wooden structures after a few minutes). The charts have been developed for pipeline diameters of 14", 16", 18", 20", 24", 30" and 36", with incident operating pressures in the range of 575 psia to 1,200 psia. It should be noted that the charts do not consider that portion of the heat flux due to solar radiation. An accurate value of the solar heat flux would be dependent on factors such as the weather conditions, the time of day and the time of year. Since the solar heat flux amounts to only a few hundred Btu/hr ft^2 while the non-solar heat flux is several thousand Btu/hr ft^2, omission of this factor will not significantly affect the results.

Comparison of Method to Pipeline Accident Data and to Previous Research

Equation 11 was evaluated by first comparing the calculated values for burn radii to data from documented pipeline accidents that occurred in the United States. The previously-mentioned accident that occurred in Edison, New Jersey is presented here as an example of the analysis that was performed.

The PAR (NTSB, 1995) for the Edison, New Jersey accident describes the rupture of a 36 inch natural gas transmission pipeline owned and operated by the Texas Eastern Transmission Corporation. The rupture occurred at approximately 11:55 p.m. on March 23, 1994, on the property of Quality Materials, Inc. in Edison, New Jersey. Ignition of the escaping gas occurred within 2 minutes after the rupture, producing flames 400 to 500 feet high. While no deaths were directly attributed to the accident, the rupture produced extensive damage including the destruction of several buildings of a nearby apartment complex. The total cost of the damage exceeded 25 million dollars. The NTSB determined that the probable caused of the rupture was mechanical damage to the exterior pipeline surface. The damage reduced the pipeline wall thickness and probably resulted in a crack that grew to a critical size.

As indicated previously, the rupture occurred at approximately 11:55 p.m., with ignition of the gas less than two minutes later. Based on the PAR, the Edison Township Fire Department arrived at the accident scene at approximately 12:02 a.m. According to information provided by the Township of Edison (personal communication, 1996) there were several buildings that were involved in fire upon arrival of the Fire Department, and there were other buildings that would have burned if those structures were not wetted down.

If buildings were set back from the pipeline at a distance beyond the location of the buildings which were involved in fire after a few minutes exposure to thermal radiation, then this distance would have provided protection for a few minutes from spontaneous ignition. Using information from the files of the NTSB, the distance from the rupture and the approximate midpoint of the footprint for the building farthest from the rupture (that was becoming involved in fire when the Fire Department arrived) was determined to be approximately 772 feet.

In order to use Equation 11, an appropriate heat flux must first be selected. Since the concern is protecting structures from spontaneous ignition for several minutes, a heat flux of 9,985 Btu/hr ft^2 from Table 3 is selected. Inserting this value for heat flux into Equation 11, as well as the applying the pipeline diameter of 36 inches and the incident operating pressure of 984.7 psia, the burn radius becomes:

$$BR = 36\{[(4{,}036.82)(984.7)/(9{,}985)] - 37.52\}^{1/2}$$
$$= 684 \text{ feet}$$

The estimated burn radius differs from the actual burn radius by less than 12 percent. It can therefore be seen that the predicted burn radius does in fact approximate the distance to those buildings which were involved in fire a few minutes after the rupture.

A burn radius can likewise be estimated for determining the distance beyond which buildings will not ignite at all. For the Edison accident, this distance would extend beyond the location of those buildings which were wetted down. In order to predict the distance with Equation 11, a heat flux of 3,962 Btu/hr ft^2 is selected. This is the heat flux at which piloted ignition of wood occurs, so that wood is not expected to ignite below this heat flux. From equation 11, the burn radius becomes:

$$\begin{aligned} BR &= 36\{[(4{,}036.82)(984.7)/(3{,}962)] - 37.52\}^{1/2} \\ &= 1{,}119 \text{ feet} \end{aligned}$$

The actual distance from the rupture point to the midpoint of the building farthest from the rupture that was wetted down was likewise found using the information from the NTSB files for this accident. This distance was determined to be 1,101 feet. The predicted burn radius is therefore very similar to the actual distance, with a difference of less that 2 percent.

The following example illustrates the analysis of a safe separation distance for a pipeline accident for which less information is available (NTSB, 1986). The accident occurred in Jacksonville, Louisiana, on November 25, 1984. The pipeline had a diameter of 30 inches and was operating at 1,016 psig (1,030.7 psia). A non-symmetrical damage area was produced, with the rupture incinerating an area 900 feet north, 500 feet south and 180 feet to the east and west of the rupture. If the burn radius is considered to be the maximum linear distance from the rupture to the edge of the incinerated area, the radius is then 900 feet. Again, using Equation 11 and a heat flux of 3,962 Btu/hr ft^2 (i.e., a conservative value for heat flux which will cause an area to be burned), the estimated burn radius becomes:

$$\begin{aligned} BR &= 30\{[(4{,}036.82)(1030.7)/3{,}962)] - 37.52\}^{1/2} \\ &= 955 \text{ feet} \end{aligned}$$

The estimated burn radius differs from the actual burn radius by only 6 percent.

Comparison to Separation Distances Developed through Hazard Analysis

Separation distances produced by Equation 11 were compared to separation distances developed through the principles of hazard analysis. For example, Hill and Catmur performed a study for the British Health and Safety Executive (1995) to evaluate how risks from various hazardous pipelines compared. As part of the study, distances from a vertical flame jet to a heat flux level of 10 kW/m^2 (3,170 Btu/hr ft^2) are provided for the pipelines under consideration. The flame was simulated as an inclined line source with a receptor 1.5 meters (4.92 feet) high at ground level. Furthermore, the authors indicate that the model which was used provides the maximum view factor between the source and receptor, with the thermal radiation being a function of the flame's emissivity, the transmissivity of the air, the view factor and the radiant energy of the burning compound.

A comparison was made between those distances and the distances estimated using Equation 11. This comparison is presented in Table 4, for all of the natural gas pipelines involved in the study. It can be seen that even outside the range of diameters and pressures for which Equation 11 was developed that this relationship still produces results which approximate those of the British. The higher percent differences reflected in the last three entries of Table 4 are probably due to the use of low operating pressures, either singly or in combination with small diameters, which are outside the range for which Equation 11 was developed.

A comparison was likewise made between separation distances determined through use of Equation 11 and the separation distances imposed in regulations developed by the Dutch. The following discussion is based on information from personal communications with N.V. Nederlandse Gasunie (November 30, 1995, June 21, 1996, September 30, 1996). The first type of separation distance which the Dutch developed is called a proximity, or building distance. This is the distance between a pipeline and residential buildings (or special structures) and corresponds to a 10^{-6} individual risk. The second type of distance is called a survey, or effect distance. This distance is determined for the purpose of identifying the location classification and corresponds to a 10^{-8} individual risk.

The Dutch regulations specify three ranges of operating pressures (in English units: 304.8 to 739.9 psia; 739.9 to 1,175.0 psia; and 1,175.0 to 1,610.1 psia) and pipeline diameters from 2 inches to 48 inches. Although the midpoints of the Dutch pressure ranges are approximately 522.3 psia, 957.4 psia, and 1,392.6 psia, the three pressures which will be used in Equation 11 for the purpose of comparison are 522.3 psia; 957.4 psia and 1,200.0 psia. The pressure of 1,200.0 psia is used in lieu of 1,392.6 psia since 1,200.0 psia represents the upper limit of pressure used to develop Equation 11, yet still lies within the third range.

The comparison is presented in Table 5. It can be seen that Equation 11 estimates significantly larger separation distances than the building distances determined by the Dutch. However, as shown through the analyses of the Edison, New Jersey accidents, the building distances developed by the Dutch will not be protective of structures. For a 36-inch diameter pipeline, the maximum building distance is 148 feet. This distance would clearly not have been protective of structures for the aforementioned accident.

Although the building distances and burn radii do not correspond, the trends in both at conditions of constant pressure (with varying diameter) and constant diameter (with varying pressure) do correspond closely. If pressure is held constant, then the following ratio is produced when using Equation 11:

$$BR_1/BR_2 = [D_1\{(4{,}036.82)P/K) - 37.52\}^{1/2}]/[D_2\{(4{,}036.82)P/K) - 37.52\}^{1/2}] = D_1/D_2 \qquad (13)$$

Where the subscripts 1 and 2 correspond to conditions at the two diameters. If diameters are held constant, then Equation 11 produces the following ratios:

$$BR_1/BR_2 = [D\{(4{,}036.82)P_1/K) - 37.52\}^{1/2}]/[D\{(4{,}036.82)P_2/K) - 37.52\}^{1/2}]$$
$$= [\{((4{,}036.82)P_1/K) - 37.52\}/\{((4{,}036.82)P_2/K) - 37.52\}]^{1/2} \qquad (14)$$

Where the subscripts 1 and 2 now correspond to conditions at the two pressures.

Tables 6 and 7 respectively present the comparison of building distances for constant pressure and diameter. It can be seen that both the Dutch approach and Equation 11 produce very similar trends (i.e. similar ratios) whether conditions of constant pressure or constant diameter are evaluated.

Uncertainties

The uncertainties in the value of the burn radius produced by Equation 11 are the result of the assumptions that were made during development of this equation. As indicated previously, an assumption was made that the damage from a pipeline rupture is primarily due to the thermal radiation produced by the ignited gas. Other damage (such as projectile damage from pipeline fragments) is not considered. This assumption is consistent with the results from investigations of actual pipeline ruptures, in which damage was found to be caused primarily from the fire.

For development of Equation 11, the escaping gas is assumed to behave, once ignited, like a vertical jet flame. A release from a pressurized system (such as a pipeline) can produce other scenarios such as dispersion of the unignited gas, formation of a fireball, development of a flash fire or a vapor cloud explosion (NFPA, 1988; Hill and Catmur, 1995; AICHE, 1994). Furthermore, the rupture orientation may be such that a flame jet, if it exists, may not be truly vertical. Assuming that all of these scenarios can occur increases the number of variables to be considered, in that the probabilities of each scenario happening (either alone or in combination with other scenarios) must be determined.

Should these other scenarios occur, there is no certainty that they will contribute significantly to the overall thermal radiation damage. For example, the dispersion of unignited gas would not produce thermal radiation damage. Vapor cloud explosions can produce damage through the generation of over pressures (Crawley, 1982). However, thermal radiation was found to be the primary cause of damage in natural gas pipeline ruptures. With regard to the development of a flash fire, very little information is currently available concerning the thermal radiation produced (AICHE, 1994). Thermal radiation hazards from burning vapor clouds are considered less significant than blast effects, and combustion associated with a flash fire lasts no more than a few tens of seconds (AICHE, 1994). While fireballs produce the highest radiation intensity, these events can be assumed to last only 10-30 seconds (Hockley and Rew, 1996). Formulas for fireball diameter, duration and hazard distances have been published (AICHE, 1994) which are functions of the mass of the fuel. However, in the case of a pipeline rupture the mass of fuel involved in a fireball is difficult to predict since the release rate varies with time.

Although there are uncertainties associated with the development of Equation 11, the analyses that were performed served to demonstrate that the assumptions made during the development of Equation 11 are appropriate. Equation 11 can be used to provide estimations of burn radii for various pipeline diameters and incident operating pressures. However, it must be stressed that safe separation distances determined through the use of Equation 11 are *estimations*. There are numerous variables, several of which have been considered in this chapter, which will influence the burn radius associated with a pipeline rupture. The advantage to using the method described in this paper is that the method is straightforward and provides reasonable estimates of actual burn radii.

Conclusions

The work described in this paper has led to the development of a method for estimating safe separation distances from natural gas transmission pipelines. This method was verified based on information from actual pipeline accidents, and provides a means to determine the safe separation distance, as a measurement of the burn radius, through knowledge of the pipeline's diameter and incident operating pressure. The method can be used by regulators to determine the distances at which future development might be placed from existing pipelines or, perhaps more realistically, the method can be used to evaluate appropriate incident operating pressures for pipelines which traverse densely populated areas.

The procedure described in this paper is easy to apply and does not require extensive computational efforts. The method is applicable to pipelines with diameters ranging from 14 inches to 36 inches and incident operating pressures from 575 psia to 1,200 psia, which constitute the majority of natural gas transmission pipelines in service in the United States. For levels of thermal radiation damage corresponding to heat flux values from 3,962 Btu/hr ft^2 to 9,985 Btu/hr ft^2, the method will predict safe separation distances ranging from 195 feet to 1,200 feet. The range of heat flux values noted above are applicable to the major consequences to life, limb and property that should be of interest to most analysts.

Although there are areas amenable to refinement, the methodology will provide reasonable estimates of safe separation distances for the ranges of diameters, incident operating pressures and values of heat flux that have been previously identified.

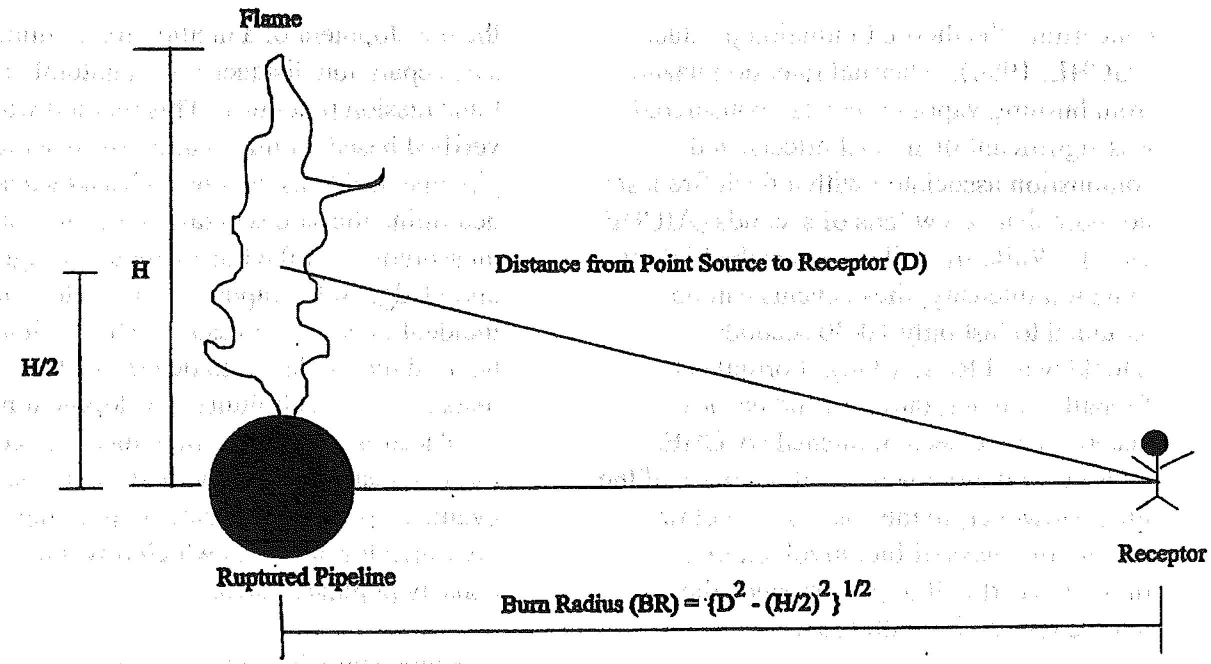


FIG. 1. Point Source Method Applied to Pipeline Rupture

FIG. 2. Burn Radius Chart

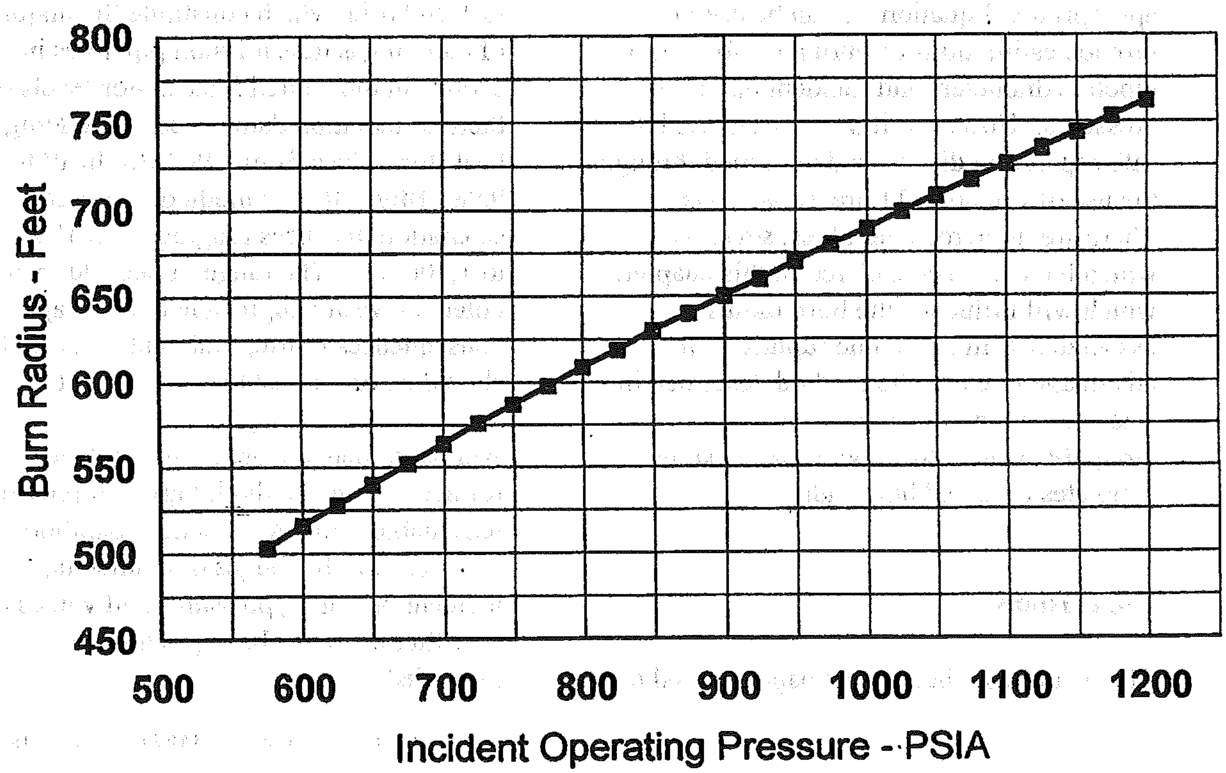


TABLE 1. Pipeline Rupture Parameters

Accident Report Number	Investigating Agency	Pipeline Diameter Inches	Incident Operating Pressure psia	Isolation time hours	Total Volume of Gas Lost, scf
P90H0606	TSB	12.75	696.7	2.75	3.78×10^7
83-02	NTSB	20	834.7	1.42	4.68×10^7
P91H0041	TSB	20	933.7	0.75	3.13×10^6
79-FP006	NTSB	30	574.7	2.83	2.01×10^8
P90H1006	TSB	30	726.7	0.58	8.73×10^7
95-01	NTSB	36	984.7	2.50	2.97×10^8
P94H0036	TSB	36	1014.7	0.63	1.48×10^8
P94H0003	TSB	42	1221.7	6.67	3.52×10^8

TABLE 2. Flame Height Data

Accident Report Number	Investigating Agency	Diameter (D) Inches	Diameter (D/12) Feet	Reported Flame Height (H) Feet	H/(D/12)
86-009	NTSB	20	1.67	300	180
95-01	NTSB	36	3.00	450	150
77-01	NTSB	20	1.67	200	120
71-01	NTSB	14	1.17	125	107
87-01	NTSB	30	2.50	450	180

TABLE 3. Examples of Heat Flux Values

Heat Flux Btu/hr ft²	kW/m²	Reference	Consequence
317	1	AICHE (1994)	Solar Heat flux during a hot summer day
2,000	6.5	Crawley (1982)	Maximum tolerable heat flux for short-term (i.e., 20 seconds) exposure for people.
3,962*	12.6	Hockey and Rew (1996) AICHE (1994) Technica International, Ltd. (1988)	Piloted ignition of wood exposed to this heat flux for a prolonged period. Also, plastic tubing melts.
9,985*	31.5	Department of Housing And Urban Development (1975)	Wooden buildings, paper, window drapes and trees will spontaneously ignite after a few minutes exposure.

*Calculated using the relationship 1 Btu/hr ft² = 3.1546 Watts/square meter (W/m²).

TABLE 4. Comparison of Natural Gas Pipelines

Pipeline Diameter Inches	Pressure Barg	Pressure Psia	Separation Distances-Feet British*	Separation Distances-Feet Equation 11	Percent Difference
42	70	1030.0	1,385	1,499	8.2
24	70	1030.0	820	857	4.5
16	70	1030.0	564	571	1.2
6	70	1030.0	226	214	5.3
24	16	246.8	443	399	9.9
24	7	116.2	351	252	28.2
6	16	246.8	138	100	27.5
6	7	116.2	95	63	33.7

*Converted from meters using the relationship 1 meter equals 3.2808 feet.

TABLE 5. Comparison of Building Distances to Safe Separation Distance

Diameter Inch	Distance from Pipeline - Feet* From Dutch Regulations: 35 Bar 522.3 psia	65 Bar 957.4 psia	95 Bar 1392.6 psia	Safe Separation Distance - Feet Using Equation 11: 35 Bar 522.3 psia	65 Bar 957.4 psia	95 Bar 1200.0 psia
14	56	66	82	184	262	296
16	66	66	82	211	299	339
18	**	66	82	237	337	381
24	**	82	82	316	449	508
30	**	98	115	395	561	635
36	**	115	148	474	673	762

Notes: * Distances converted from meters to feet using the relationship 1 meter equals 3.2808 feet.
** Distances determined on a case by case basis.

TABLE 6. Ratios of Building and Separation Distances at Various Diameters (Constant Pressure)

Diameter Ratio Selected	Ratios of Building Distances (Using Dutch Regulations): 35 Bar 522.3 psia	65 Bar 957.4 psia	95 Bar 1392.6 psia	Ratios of Separation Distances (Using Equation 11): 35 Bar 522.3 psia	65 Bar 957.4 psia	95 Bar 1200.0 psia
16"/14"	1.18	1.00	1.00	1.14	1.14	1.14
18"/14"	----	1.00	1.00	1.29	1.29	1.29
24"/14"	----	1.24	1.00	1.71	1.71	1.71
30"/14"	----	1.48	1.40	2.14	2.14	2.14
36"/14"	----	1.74	1.80	2.57	2.57	2.57
18"/16"	----	1.00	1.00	1.13	1.13	1.13
24"/16"	----	1.24	1.00	1.50	1.50	1.50
30"/16"	----	1.48	1.40	1.88	1.88	1.88
36"/16"	----	1.74	1.80	2.25	2.25	2.25
24"/18"	----	1.24	1.00	1.33	1.33	1.33
30"/18"	----	1.48	1.40	1.67	1.67	1.67
36"/18"	----	1.74	1.80	2.00	2.00	2.00
30"/24"	----	1.20	1.40	1.25	1.25	1.25
36"/24"	----	1.40	1.80	1.50	1.50	1.50
36"/30"	----	1.17	1.29	1.20	1.20	1.20

TABLE 7. Ratios of Building and Separation Distances at Various Pressures (Constant Diameter)

	Ratios of Building Distances (Using Dutch Regulations)			Ratios of Separation Distances (Using Equation 11)		
OD	957.4/522.3 psia	1,392.6/522.3 psia	1,392.6/957.4 psia	957.4/522.3 psia	1,200.0/522.3 psia	1,200.0/957.4 psia
14"	1.18	1.46	1.24	1.42	1.61	1.13
16"	1.00	1.24	1.24	1.42	1.61	1.13
18"	----	----	1.24	1.42	1.61	1.13
24"	----	----	1.00	1.42	1.61	1.13
30"	----	----	1.17	1.42	1.61	1.13
36"	----	----	1.29	1.42	1.61	1.13

APPENDIX I. REFERENCES

Arkla Energy Resources Pipeline Rupture & Fire Near Cale, Arkansas 02-24-86. National Transportation Safety Board accident file, Washington, D.C.

Guide for Pressure-Relieving and Depressuring Systems. API Recommended Practice 521. (1990). American Petroleum Institute, Washington, D.C.

Brzustowski, T.A., and Sommer, E.C., Jr. (1973). "Predicting Radiant Heating from Flares." From *Proceedings - Division of Refining.* American Petroleum Institute, Vol. 53, Washington, D.C., 865-893.

Crawley, F.K. (1982). "The Effects of the Ignition of a Major Fuel Spillage." *I. Chem. E. Symposium Series No. 71.* 125-145.

Factual Pipeline Accident Report Basic Report (AR-01) FTW-79-F-P006 United Texas Transmission Co. (1979). National Transportation Safety Board, Washington, D.C.

Guidelines for Evaluating the Characteristics of Vapor Cloud Explosions, Flash Fires, and BLEVEs. (1994). Center for Chemical Process Safety of the American Institute of Chemical Engineers, New York, N.Y.

Hawthorne, W.R., Weddell, D.S., and Hottell, H.C. (1949). "Mixing and Combustion in Turbulent Gas Jets." *Third Symposium on Combustion, Flame and Explosion Phenomena.* Combustion Institute, 266-288.

Hill, R.T., and Catmur, J.R. (1995). "Risks from Hazardous Pipelines in the United Kingdom." *HSE Contract Research Report No. 82/1994.*

Hockey, S.M., and Rew, P.J. (1996). "Review of Human Response to Thermal Radiation." *HSE Contract Research Report No. 97/1996.*

Mobil Oil Corporation High-Pressure Natural

Natural Gas Pipeline, Near Houston, Texas September 9, 1969. (1971). National Transportation Safety Board, Washington, D.C.

Northern Natural Gas Company Pipeline Puncture, Explosion and Fire Hudson, Iowa November 4, 1982. (1983). National Transportation Safety Board, Washington, D.C.

Natural Gas Pipeline Rupture Foothills Pipe Lines (Sask.) Ltd. 1,067-Millimetre (42-Inch) Eastern Main Line Kilometre Post 66 + 041 Maple Creek, Saskatchewan 15 February 1994. (1995). Transportation Safety Board of Canada, Hill, Quebec, Canada.

Oenbring, P.R., and Sifferman, T.R. (May 1980). "Flare Design...Are Current Methods Too Conservative?" *Hydrocarbon Processing,* 124-129.

Pipeline Accident/Incident Summary Reports. (1986). National Transportation Safety Board, Washington, D.C.

Pipe Line Rules of Thumb Handbook. (1993). Gulf Publishing Company, Houston, TX.

SFPE Handbook of Fire Protection Engineering. (1988). National Fire Protection Association, Quincy, MA.

Safety Considerations in Siting Housing Projects. (1975). Department of Housing and Urban Development, Washington, D.C.

Texas Eastern Gas Pipeline Company Ruptures and Fires at Beaumont, Kentucky on April 27, 1985 and Lancaster, Kentucky on February 21, 1986. (1987). National Transportation Safety Board, Washington, D.C.

Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire Edison, New Jersey March 23, 1994. (1995). National Transportation Safety Board, Washington, D.C.

Transcanada Pipeline Limited Line 300-1, Natural Gas Pipeline Rupture Kilometre Post MLV 302-1 + 2.849 KM Marionville, Ontario 1705 EDT, 06 June 1990. (1992). Transportation Safety Board of Canada, Hull, Quebec, Canada.

Transcanada Pipelines Limited Natural Gas Pipeline Rupture Line 100-2, 914 Millimetre (36-Inch) Mainline Kilometre Post Main Line Valve 110-2 + 22.098 Kilometres Latchford, Ontario 23 July 1994. (1995). Transportation Safety Board of Canada, Hull, Quebec, Canada.

Transcanada Pipelines Limited Natural Gas Pipeline Ruptures Main Line Valve 144-1 + 19.261 km Cardinal, Ontario 08 December 1991. (1994). Transportation Safety Board of Canada, Hull, Quebec, Canada.

United Gas Pipe Line Company 20-Inch Pipeline Rupture and Fire Cartwright, Louisiana August 9, 1976. (1977). National Transportation Safety Board, Washington, D.C.

Westcoast Energy Inc. 30-Inch Fort Nelson Main Line Natural Gas Pipeline Rupture Mile Post 102.6 Pink Mountain, British Columbia 1545 PDT, 06 October 1990. (1993). Transp. Safety Bd. of Canada, Hull, Quebec, Canada.

APPENDIX II. NOTATION

The following abbreviations and symbols are used in this paper:

AICHE	American Institute of Chemical Engineers
API	American Petroleum Institute
BR	burn radius
Btu	British Thermal Unit
D	diameter, distance from flame center to observer
F	fraction of total heat radiated
ft	foot
°F	degrees Fahrenheit
g	gauge pressure designation
H	flame height
hr	hour
in	inch
K	radiant heat flux
Mcf	thousand cubic feet
NFPA	National Fire Protection Association
NTSB	National Transportation Safety board
P	incident operating pressure
P'	gauge operating pressure
P_1	absolute pressure near the opening
PAR	Pipeline Accident Report
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
Q	total heat content of flared gas, volumetric gas flow rate
ROW	right-of-way
scf	standard cubic feet
τ	atmospheric transmissivity
TSB	Transportation Safety Board (Canada)
V'	volumetric gas flow rate

James S. Haklar, Ph.D., P.E., is an Adjunct Professor in the Department of Civil and Environmental Engineering at the New Jersey Institute of Technology (NJIT), and is also an Environmental Engineer for the U.S. Environmental Protection Agency (EPA). It should be noted that the views expressed in this paper are not intended to reflect EPA policy.

Robert Dresnack, Ph.D., P.E., is a Professor of Civil and Environmental Engineering at NJIT.

Attachment D

A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines

Attachment E

Kinder Morgan Utopia v. PDB Farms of Wood County, LLC

FILED
WOOD COUNTY CLERK
COMMON PLEAS COURT

2016 OCT 12 PM 1:12

CINDY A. HOFNER

IN THE COURT OF COMMON PLEAS OF WOOD COUNTY, OHIO

Kinder Morgan Utopia, LLC,
Plaintiff,

Case No. 2016CV0220

vs.

JUDGMENT ENTRY

PDB Farms of Wood County, LLC, et al.,
Defendants.

Judge Robert C. Pollex

This matter was before the Court for a necessity hearing as to the Utopia Pipeline on August 11, 2016. This matter was also before the Court on Defendants' Motion for Partial Judgment on the Pleadings and Partial Summary Judgment filed on July 15, 2016. With regard to the Motion for Summary Judgment, the Court currently has before it the following evidence:

1. "Declaration of Necessity," enacted as a corporate resolution by Plaintiff, Kinder Morgan Utopia, LLC ("Kinder Morgan");
2. Defendants' Verified Answers, specifically denying Kinder Morgan's right to make the appropriation and the necessity for the appropriation;
3. Kinder Morgan's Discovery Responses;
4. Kinder Morgan's press release indicating that the Utopia Pipeline is being constructed for the benefit of, alongside Kinder Morgan, a private Nova Chemicals facility in Canada;

JOURNALIZED
OCT 12 2016

5. "Frequently Asked Questions," indicating that the Utopia Pipeline is being constructed for the benefit of, alongside Kinder Morgan, a private Nova Chemicals facility in Canada;
6. Kinder Morgan's July 26, 2016 Affidavit of Allan Campbell and attached FERC documentation;
7. Affidavits of numerous property owners neighboring Defendants who have been sued in this case, indicating that they may have considered an offer from Kinder Morgan to run the Utopia Pipeline across their land, but were never contacted by Kinder Morgan, submitted for the purpose of demonstrating that Kinder Morgan did not consider certain alternative routes; and
8. Internet news articles indicating that Kinder Morgan has moved the Utopia Pipeline in response to landowner objections, submitted for the purpose of demonstrating that the Utopia Pipeline can be moved and neither its proposed route across Defendants' properties nor the use of eminent domain to effectuate that route is necessary.

The Court must determine whether the appropriation of Defendants' property for the Utopia Pipeline is necessary and for a public use.

Conclusions of law

The initiation of this proceeding began with Kinder Morgan's "Declaration of Necessity," a corporate resolution adopted by Kinder Morgan. In essence, the Utopia Pipeline will serve the purpose of transporting petroleum products of a nature not used for energy such as gasoline or natural gas, but rather used to make plastic products. The petroleum products are to pass through this pipeline, connecting with an existing pipeline at the Michigan-Ohio border, which travels up to Canada near the city of Windsor, to a private business engaged in the manufacturing of plastic products. On its face, this appears not to be a public use as argued by the Defendants, but the difficulty arises in the statutory authority upon which Kinder Morgan relies. Accordingly, it would be best to first analyze the nature and principles of eminent domain.

The principles of law related to eminent domain are very clearly set out in the Ohio Supreme Court case of *Norwood v. Horney,* 110 Ohio St. 3d 353, 2006-Ohio-3799, 853 N.E.2d 1115. *Norwood* deals with the action of the City of Norwood, Ohio in declaring certain property blighted or deteriorated for the purposes of redevelopment and suggested that the taking was proper even though the City transferred the appropriated property to a private party. The court cited the Ohio and U.S. Constitutions in particular reference to the case of *Kelo v. City of New London,* 545 U.S. 469, 125 S. Ct. 2655, 162 L. Ed. 2d 439 (2005), which resulted in the Ohio General Assembly in enacting 2005 Am.Sub.S.B.167 in response. The Court in *Norwood* found that the void-for-vagueness doctrine applies to statutes permitting the use of eminent domain powers to take private property and that courts shall apply heightened scrutiny when reviewing those statutes. The court went on to find a provision of R.C. 163.19 unconstitutional and severed that provision so that the remainder of the statute could remain in effect. In this case, Kinder Morgan argues that the deteriorating neighborhood use situation does not apply to the facts in this case and that therefore the holding of the Ohio Supreme Court does not apply.

I. Individual Property Rights

Rights relating to private property include the right to acquire, use, enjoy, and dispose of property and is a fundamental right declared in the U.S. Constitution in the Fifth and Fourteenth Amendments and in the Ohio Constitution. Ohio expressly incorporated individual property rights into its Constitution in terms that reinforced the sacrosanct nature of individual property rights—Section 1, Article I and Section 19, Article I and Section 5, Article III. Ownership and use of

JOURNALIZED
OCT 12 2016

private property is a fundamental right existing even prior to the creation of our nation under its current Constitution. The fundamental principles in the Bill of Rights in our Constitution declares the inviolability of private property, and Ohio has always considered the right of property to be a fundamental right. *See Reece v. Kyle*, 49 Ohio St. 475, 31 N.E. 747 (1892). "It is axiomatic that the federal and Ohio constitutions forbid the state to take private property for the sole benefit of a private individual [or business], even when just compensation for the taking is provided." *Norwood, supra* at 365, citing *O'Neil v. Summit Cty. Bd. Of Commrs.,* 3 Ohio St.2d 53, 57, 209 N.E.2d 393 (1965). In this case, the taking is not being initiated by a governmental body, be it a state or municipality. However, the Ohio statutes set forth herein appear to authorize the taking. It has been held that the plaintiff or the "taker" can be a private entity as in the case of *Fallbrook Irrigation District v. Bradley,* 164 U.S. 112, 17 S.Ct. 56, 41 L.Ed. 369 (1896). However, in that case, the private taking was for a public use, that is, to build reservoirs and ditches to supply land owners (the public) with water.

In determining whether a public use exists in this case, it is enlightening to examine the *Norwood* case further. "Generally a public purpose has for its objectives the promotion of public health, safety, morals, general welfare, security, prosperity, and contentment of all * * *." *Norwood* at 369, quoting *State ex rel. Gordon v. Rhodes*, 156 Ohio St.81, 91-92, 100 N.E.2d 225 (1951). The concept of public use under eminent domain law has been expanded to include municipalities and private developers for proposed public facilities and even retail outlets and malls. As the *Norwood* case pointed out, in determining whether the use is public, it must have the objective of promoting the public health and welfare. Significantly though, the court drew a line that found "economic development" alone is not sufficient to satisfy public use requirements. The process of having a necessity hearing, as was done in this case, is to examine this exact issue. This Court cannot ignore the precedent set in the *Norwood* case by the Ohio Supreme Court even though Kinder Morgan would like the Court to find that it does not apply here. Clearly it is not exactly the same factual circumstance. However, in this case Kinder Morgan is taking the private property (by easement across the farmland of multiple farmers) for the purpose of transporting by pipeline petroleum products for the use of one private manufacturer. The manufacturer is not even a United States business, but rather a Canadian business. Its products may eventually end up in the United States or even in Ohio, but there is no anticipated circumstance that would show a benefit to the citizens of Ohio or even for that matter, the United States. Like in the *Norwood* case, the fact that there is an economic motive does not make this a public use.

During the course of the necessity hearing, Kinder Morgan's own expert admitted that the use did not contain or include energy distribution such as natural gas, electricity, etc. The statute that Kinder Morgan is relying upon is primarily for the purpose of serving energy needs of the Ohio public. The conveyance of the pipeline is for the purpose of manufacturing to occur in Canada, not the United States. The hearing also established that Kinder Morgan had only one committed shipper that is paying the cost of the construction of the pipeline, and the user, Nova Chemicals, will solely utilize the pipeline. Kinder Morgan alleges that the pipeline would be available to "walk-up shippers" who are third parties who could use the capacity of the Utopia Pipeline in the future. However, Kinder Morgan admits that there are no such users at this time and therefore the Court is forced to conclude that any such users would likewise be a limited number of commercial enterprises engaged only for the economic benefit and use of those manufacturers. Thus, it is clear that the Utopia Pipeline does not benefit the public in any way and therefore the property rights of the owners should not be burdened with the encumbrance.

JOURNALIZED
OCT 12 2016

Kinder Morgan contends that R.C. 163.04 and 163.041 authorize it to petition the court to appropriate the Defendants' property in this case. The Ohio appropriation statutes are contained in R.C. Chapter 1723 and specify that appropriations, such as in this case, must be accomplished pursuant to R.C. Chapter 163. In this case as previously noted, the appropriation is not under the jurisdiction of any governmental entity such as the Ohio Department of Transportation, Board of County Commissioners, a municipality, or the state. R.C. 1723.08 specifically states that a company organized to transport petroleum through pipelines is a common carrier, and Ohio courts have consistently held that a common carrier is one who holds itself out to the public as engaged in the business of transporting persons or property for compensation. Typically such public transportation involves things such a railroads, highways, trucking companies, and other businesses engaged in transporting people or property. Kinder Morgan cannot claim to be a common carrier as a matter of fact. Kinder Morgan is not offering its services to the public or even to an unlimited number of commercial enterprises. Its sole purpose is to convey a petroleum derivative to a company in Canada who is willing to pay the costs. This is not a common carrier in any sense of the word. Kinder Morgan has failed to establish any activities that establish it as a common carrier.

It is astonishing to this Court that Kinder Morgan is able to make its own determination to proceed and not be required to obtain any permit or permission from a governmental entity. For certain types of appropriations, R.C. 163.09(B)(1) establishes an irrebuttable presumption of necessity for the appropriation upon a showing of approval by a state or federal regulatory authority. Such is not the case here. This Court is the first and last opportunity for these Defendants to exercise their property rights. The cases cited by Kinder Morgan require a showing that the proposed product is "reasonably convenient or useful to the public." This Court is not questioning the right of the Ohio legislature to confer the right of eminent domain to public utilities, municipalities, and common carriers. However, this Court is finding that the proposed use and purpose of the pipeline in this case is not to the benefit of the public and clearly is not necessary. Kinder Morgan admits in their brief that Ohio law extends common carrier status to companies, but only so long as they operate in the public interest generally. R.C. 163.08 specifically recognizes that private entities have eminent domain authority under Ohio law, but only if the use benefits the public interest generally.

Only the Judge can determine the necessity of the appropriation. In *Bluegrass Pipeline Co., LLC v. Kentuckians United to Restrain Eminent Domain, Inc.*, 478 S.W.3d 386 (Ky.App.2015), the court held the Bluegrass Pipeline Company did not have the power of eminent domain. The court found that the state's power to grant eminent domain to pipeline companies should be regulated and that the pipeline at issue could not be said to be in the public service of the state. This Court finds that this pipeline to be constructed by Kinder Morgan likewise does not serve the public of the State of Ohio or any public in the United States. This is not to say the Court is ruling that the pipeline company has to be organized or incorporated under Ohio law or even that it has to be regulated by an Ohio governmental agency, if the legislature provides otherwise. Accordingly, this Court finds that Kinder Morgan is not a common carrier as referred to in the Ohio statutes as it provides no public benefit. The Court also finds that this project and appropriation is not necessary nor a public use. To the extent that the Ohio statutes authorize a common carrier of Kinder Morgan's type, that legislation is an unconstitutional infringement upon the property rights of the Defendants. Accordingly, this Court finds that the Petition should be dismissed.

JOURNALIZED

OCT 12 2016

JUDGMENT ENTRY

IT IS THEREFORE ORDERED, ADJUDGED, AND DECREED that the Plaintiff has failed to establish the necessity of the appropriation and therefore the Petition is hereby dismissed.

IT IS FURTHER ORDERED, ADJUDGED, AND DECREED that to the extent the Ohio appropriation statutes permit the appropriation as alleged by Kinder Morgan, then and only to that extent as it applies to this case, said statutes are unconstitutional and an infringement upon the property owners' constitutional rights.

Judgment for court costs rendered to Wood County

Judge Robert C. Pollex

CLERK TO FURNISH TO ALL COUNSEL OF RECORD AND UNREPRESENTED PARTIES NOT IN DEFAULT FOR FAILURE TO APPEAR WITH A COPY OF THIS ENTRY INCLUDING THE DATE OF ENTRY ON THE JOURNAL

JOURNALIZED

OCT 12 2016

Attachment F

Bluegrass Pipeline Company v. Kentuckians United to Restrain Eminent Domain

RENDERED: MAY 22, 2015; 10:00 A.M.
TO BE PUBLISHED

Commonwealth of Kentucky

Court of Appeals

NO. 2014-CA-000517-MR

BLUEGRASS PIPELINE COMPANY, LLC APPELLANT

v.

APPEAL FROM FRANKLIN CIRCUIT COURT
HONORABLE PHILLIP J. SHEPHERD, JUDGE
ACTION NO. 13-CI-01402

KENTUCKIANS UNITED TO RESTRAIN
EMINENT DOMAIN, INC. APPELLEE

OPINION
AFFIRMING

** ** ** ** **

BEFORE: J. LAMBERT, STUMBO AND TAYLOR, JUDGES.

STUMBO, JUDGE: Bluegrass Pipeline Company, LLC appeals from an opinion and order of the Franklin Circuit Court which granted summary judgment in favor of Kentuckians United to Restrain Eminent Domain, Inc. (hereinafter referred to as KURED). The order held, among other things, that Bluegrass Pipeline did not have the power to condemn property pursuant to eminent domain. We find no error and affirm.

The trial court in this case set forth a detailed summary of the necessary facts of this case; therefore, we will utilize it.

> Plaintiff, Kentuckians United to Restrain Eminent Domain, Inc (hereinafter "KURED") is a non-profit, incorporated under the laws of the Commonwealth of Kentucky, whose purpose is "to protect Kentuckians from the threat of and attempts to exercise eminent domain by entities not in the public service to Kentuckians." *Plaintiff's Motion for Summary Judgment*, p. 4. Defendant, Bluegrass Pipeline Company, LLC (hereinafter "Bluegrass"), is a limited liability company with its principal office in Tulsa, Oklahoma, but with a registered office in Frankfort, Kentucky. Bluegrass is a joint venture of Williams Company and Boardwalk Pipeline Partners which proposes a 24-inch pressurized underground pipeline for transporting natural gas liquids (hereinafter "NGLs") (a mixture of pentane, propane, butane, isobutene, and ethane) from the Marcellus and Utica shale formations in Pennsylvania, West Virginia, and Ohio, to the Gulf of Mexico. Among KURED's members (and also serving on its Board of Directors) is Penny Greathouse, a resident of Franklin County whose property is located along the initial path of the proposed Bluegrass [pipeline]. Ms. Greathouse has been approached by representatives of Bluegrass to survey her property for a potential location of an easement for the pipeline, and has spoken with Rich Ellis on four different occasions in which Mr. Ellis has said that the company has the right of eminent domain, but did not like to exercise it. *Affidavit of Penny Greathouse*.
>
> Plaintiff filed this action in Franklin Circuit Court on December 5, 2013 seeking a declaration of rights under KRS 418.040 as to the validity of the claim of Bluegrass that it has the power of eminent domain under Kentucky law. Plaintiff seeks a ruling adjudicating the right of Bluegrass to invoke KRS 278.502 [(statute regarding

> condemnation for the construction of oil and gas pipelines)], KRS 416.675 [(statute defining public use as it relates to the Kentucky Eminent Domain Act)], and KRS 278.470 [(statute stating that the delivery of natural gas through a pipeline is a public use)] to use eminent domain to condemn properties to install a natural gas liquids pipeline through Franklin County and other counties in Kentucky.

About three months after filing its complaint, KURED moved for summary judgment. A hearing was held on March 10, 2014. On March 25, 2014, the circuit court entered an order which granted summary judgment in favor of KURED and held that Bluegrass did not have the right to invoke eminent domain. This appeal followed.

> The standard of review on appeal of a summary judgment is whether the trial court correctly found that there were no genuine issues as to any material fact and that the moving party was entitled to judgment as a matter of law. Kentucky Rules of Civil Procedure (CR) 56.03. . . . "The record must be viewed in a light most favorable to the party opposing the motion for summary judgment and all doubts are to be resolved in his favor." *Steelvest, Inc. v. Scansteel Service Center, Inc.,* 807 S.W.2d 476, 480 (Ky. 1991). Summary "judgment is only proper where the movant shows that the adverse party could not prevail under any circumstances." *Steelvest,* 807 S.W.2d at 480, *citing Paintsville Hospital Co. v. Rose,* 683 S.W.2d 255 (Ky. 1985). Consequently, summary judgment must be granted "[o]nly when it appears impossible for the nonmoving party to produce evidence at trial warranting a judgment in his favor. . . ." *Huddleston v. Hughes,* 843 S.W.2d 901, 903 (Ky. App. 1992)[.]

Scifres v. Kraft, 916 S.W.2d 779, 781 (Ky. App. 1996). "Because summary judgment involves only legal questions and the existence of any disputed material issues of fact, an appellate court need not defer to the trial court's decision and will review the issue *de novo*." *Lewis v. B & R Corporation*, 56 S.W.3d 432, 436 (Ky. App. 2001). The case at hand does not involve disputed material issues of fact, only questions of law.

Bluegrass's first argument on appeal is that the circuit court should have refused to issue a declaratory judgment because there was no ripe, justiciable controversy. Bluegrass argues that there is no justiciable controversy because it has not taken any steps to initiate eminent domain proceedings against anyone in Kentucky. Bluegrass claims that until a condemnation action is pursued, any controversy is merely speculative.

"Any person . . . whose rights are affected by statute . . . or who is concerned with any title to property, . . . provided always that an actual controversy exists with respect thereto, may apply for and secure a declaration of his right or duties[.]" KRS 418.045. "For a cause to be justiciable, there must be a present and actual controversy presented in good faith by parties with adverse interests in the subject to be adjudicated." *Appalachian Racing, LLC v. Family Trust Foundation of Kentucky, Inc.*, 423 S.W.3d 726, 735 (Ky. 2014).

This issue was raised at the summary judgment hearing before the trial court. The trial court believed that there was justiciable controversy because Bluegrass is claiming that it has the power to condemn property under eminent domain. The court stated that "[p]roperty owners and taxpayers in general have a right to determine whether Bluegrass's claim is valid because not only does it affect their bargaining position, but it affects their legitimate interests and substantive rights as citizens when a private company seeks to exercise the sovereign power of condemnation." The court further held that a

> declaration of rights is necessary to determine whether Bluegrass has the right to condemn so that Ms. Greathouse and other landowners, who are within the ever changing present or future pathway of the proposed pipeline, can make informed decisions considering all factors when negotiating and deciding whether to grant an easement to Bluegrass and other private entities.

We agree with the trial court. Declaratory judgments are "declared to be remedial; their purpose is to make courts more serviceable to the people by way of settling controversies, and affording relief from uncertainty and insecurity with respect to rights, duties and relations, and are to be liberally interpreted and administered." KRS 418.080.

> This Court is not authorized to give advisory opinions on hypothetical factual situations, but it may declare the rights of litigants in advance of action when it concludes that a justiciable controversy is presented, the advance determination of which would eliminate or minimize the risk of wrong action by any of the parties. Justiciability turns on "evaluating both the appropriateness of the issues for decision . . . and the hardship of denying judicial relief."

Combs v. Matthews, 364 S.W.2d 647, 648 (Ky. 1963) (citations omitted).

In the case at hand, Bluegrass is actively negotiating with landowners. The threat of acquiring land through eminent domain has a current and material impact on negotiations between Bluegrass and landowners. As KURED and the trial court point out, landowners may grant voluntary easements over their property because they do not have the means to engage in litigation to determine the issue. If the eminent domain issue remains unresolved, it would give Bluegrass an unfair advantage during the negotiation process. We find no error on the issue of justiciability.

Bluegrass's second argument on appeal is that KURED lacked standing to bring the declaratory action.

> Standing . . . focuses on whether the parties before the court have a personal stake in the outcome of controversy. "In order to have standing to sue, a plaintiff need only have a real and substantial interest in the subject matter of the litigation, as opposed to a mere expectancy." "The purpose of requiring standing is to make sure that the party litigating the case has a 'personal stake in the outcome of the controversy' such that he or she will litigate vigorously and effectively for the personal issues." The determination of a party's standing requires consideration of the facts of each individual case.

Interactive Gaming Council v. Commonwealth ex rel. Brown, 425 S.W.3d 107, 112 (Ky. App. 2014) (citations omitted).

KURED is not a landowner; therefore, it has no personal stake in this case. KURED relied on associational standing in order to bring this cause of action.

> [A]n association has standing to bring suit on behalf of its members when: (a) its members would otherwise have standing to sue in their own right; (b) the interests it seeks to protect are germane to the organization's purpose; and (c) neither the claim asserted nor the relief requested requires the participation of individual members in the lawsuit.

Id. at 113 (*citing Hunt v. Washington State Apple Advertising Com'n,* 432 U.S. 333, 343, 97 S.Ct. 2434, 2441, 53 L.Ed.2d 383 (1977)).

Bluegrass claims that KURED lacks associational standing because none of its members has standing to sue in his or her own right. Ms. Greathouse is a member of KURED and KURED relied on her membership in seeking to utilize associational standing. Bluegrass asserts Ms. Greathouse does not have standing in her own right because once she declined to sell the company an easement, it changed the route of the pipeline to bypass her property. Bluegrass argues that once it decided to bypass her property, she no longer had a personal claim.

We believe that KURED has associational standing to bring this declaratory action, through Ms. Greathouse, even though Bluegrass changed the pipeline route. Ms. Greathouse was approached on four different occasions by Bluegrass seeking an easement through her property. Even though Bluegrass has changed the route of the pipeline, it could easily be changed again to go through Ms. Greathouse's property.

In addition, the trial court believed that KURED could bring this action because its members are citizens of Kentucky. We agree. Kentucky courts have recognized the rights of citizens to bring suits to challenge the wrongful exercise of government power. *See Rose v. Council for Better Educ., Inc.*, 790 S.W.2d 186, 201 (Ky. 1989); *Russman v. Luckett*, 391 S.W.2d 694, 696 (Ky. 1965). Here, Ms. Greathouse, as a citizen of Kentucky, could bring this declaratory action against Bluegrass on her own behalf. Even though Bluegrass is not a public or government entity, it is alleging that it has the power to utilize the government power of eminent domain. We find no error on the issue of standing.

Bluegrass's final argument on appeal is that it has the power to invoke eminent domain pursuant to KRS 278.502. "The construction and application of statutes is a matter of law and may be reviewed *de novo*." *Bob Hook Chevrolet Isuzu, Inc. v. Com. Transp. Cabinet*, 983 S.W.2d 488, 490 (Ky. 1998). KRS 278.502 states:

> Any corporation or partnership organized for the purpose of, and any individual engaged in or proposing to engage in, constructing, maintaining, or operating oil or gas wells or pipelines for transporting or delivering oil or gas, including oil and gas products, <u>in public service</u> may, if it is unable to contract or agree with the owner after a good faith effort to do so, condemn the lands and material or the use and occupation of the lands that are necessary for constructing, maintaining, drilling, utilizing, and operating pipelines, underground oil or gas storage fields, and wells giving access thereto and all necessary machinery, equipment, pumping stations, appliances, and fixtures, including tanks and telephone lines, and other communication facilities, for use in connection therewith, and the necessary rights of ingress and egress to construct, examine, alter, repair, maintain, operate, or remove such pipelines or underground gas storage fields, to drill new wells and utilize existing wells in connection therewith, and remove pipe, casing, equipment, and other facilities relating to such underground storage fields and access wells. The proceedings for condemnation shall be as provided in the Eminent Domain Act of Kentucky. [Emphasis added].

In granting summary judgment, the trial court believed that KRS 278.502 only granted condemnation powers to entities providing public utilities regulated by the Public Service Commission. It also believed that since the pipeline was only going to be utilized to move NGLs to the Gulf of Mexico, the pipelines would not be "in public service." We agree.

KRS Chapter 278 is entitled "Public Service Commission" (hereinafter PSC) and is dedicated to public utilities. Bluegrass is not regulated by the PSC. While it is true that "[t]itle heads, chapter heads, section and subsection heads or titles, and explanatory notes and cross references, in the Kentucky Revised Statutes, do not constitute any part of the law," KRS 446.140, we must still "construe statutes within their context and strive to give consistent meaning to related statutory provisions." *Rogers v. Fiscal Court of Jefferson County*, 48 S.W.3d 28, 31 (Ky. App. 2001) (citations and internal quotation marks omitted). KRS 278.502 is found in the statutory chapter dedicated to the PSC and public utilities. We believe that the legislature only intended to delegate the state's power of eminent domain to those pipeline companies that are, or will be, regulated by the PSC. In addition, the NGLs in Bluegrass's pipeline are being transported to a facility in the Gulf of Mexico. If these NGLs are not reaching Kentucky consumers, then Bluegrass and its pipeline cannot be said to be in the public service of Kentucky. We therefore affirm the circuit court's judgment that Bluegrass does not possess the ability to condemn property through eminent domain.

Based on the foregoing reasons, we affirm the judgment of the Franklin Circuit Court.

ALL CONCUR.

BRIEFS FOR APPELLANT:

Gregory P. Parsons
William T. Gorton, III
Chadwick A. McTighe
Lexington, Kentucky

BRIEF FOR AMICUS CURIAE
KENTUCKY OIL AND GAS
ASSOCIATION

John Kevin West
D. Eric Lycan
Lexington, Kentucky

ORAL ARGUMENT FOR
APPELLANT:

Chadwick A. McTighe
Louisville, Kentucky

BRIEF FOR APPELLEE:

Thomas J. FitzGerald
Frankfort, Kentucky

BRIEF FOR AMICUS CURIAE
AMERICAN CIVIL LIBERTIES
UNION OF KENTUCKY

William Sharp
Legal Director of ACLU of Kentucky
Louisville, Kentucky

Randal A. Strobo
Midway, Kentucky

ORAL ARGUMENT FOR
APPELLEE:

Thomas J. FitzGerald
Frankfort, Kentucky

MINNESOTA DEPARTMENT OF COMMERCE

3

RESIDENCES, COMMERCIAL AND OUT BUILDINGS AND MINNESOTA POLLUTION CONTROL AGENCY LISTINGS

ROCHESTER NATURAL GAS PIPELINE

FIGURE 10 (PAGE 1 OF 10)

COMPARATIVE ENVIRONMENTAL ANALYSIS

MINNESOTA DEPARTMENT OF COMMERCE

③

RESIDENCES, COMMERCIAL AND OUT BUILDINGS AND MINNESOTA POLLUTION CONTROL AGENCY LIS

ROCHESTER NATURAL GAS

FIGURE 10 (PAGE

5

4

RESIDENCES, COMMERCIAL AND OUT BUILDINGS AND MINNESOTA POLLUTION CONTROL AGENCY L

ROCHESTER NATURAL GA

FIGURE 10 (PA

MINNESOTA DEPARTMENT OF COMMERCE

MINNESOTA DEPARTMENT OF COMMERCE

2

RESIDENCES, COMMERCIAL AND OUT BUILDINGS AND MINNESOTA POLLUTION CONTROL AGENCY LIST

ROCHESTER NATURAL GAS

FIGURE 10 (PAGE

2

Will Oldfield

RESIDENCES, COMMERCIAL AND OUT BUILDINGS AND MINNESOTA POLLUTION CONTROL AGENCY

ROCHESTER NATURAL GA

FIGURE 10 (PA

MINNESOTA DEPARTMENT OF COMMERCE

MINNESOTA DEPARTMENT OF COMMERCE

2

RESIDENCES, COMMERCIAL AND OUT BUILDINGS AND MINNESOTA POLLUTION CONTROL AGENCY LISTIN

ROCHESTER NATURAL GAS PIPE

FIGURE 10 (PAGE 4 O

13 purple 1 orange 2 adjacent

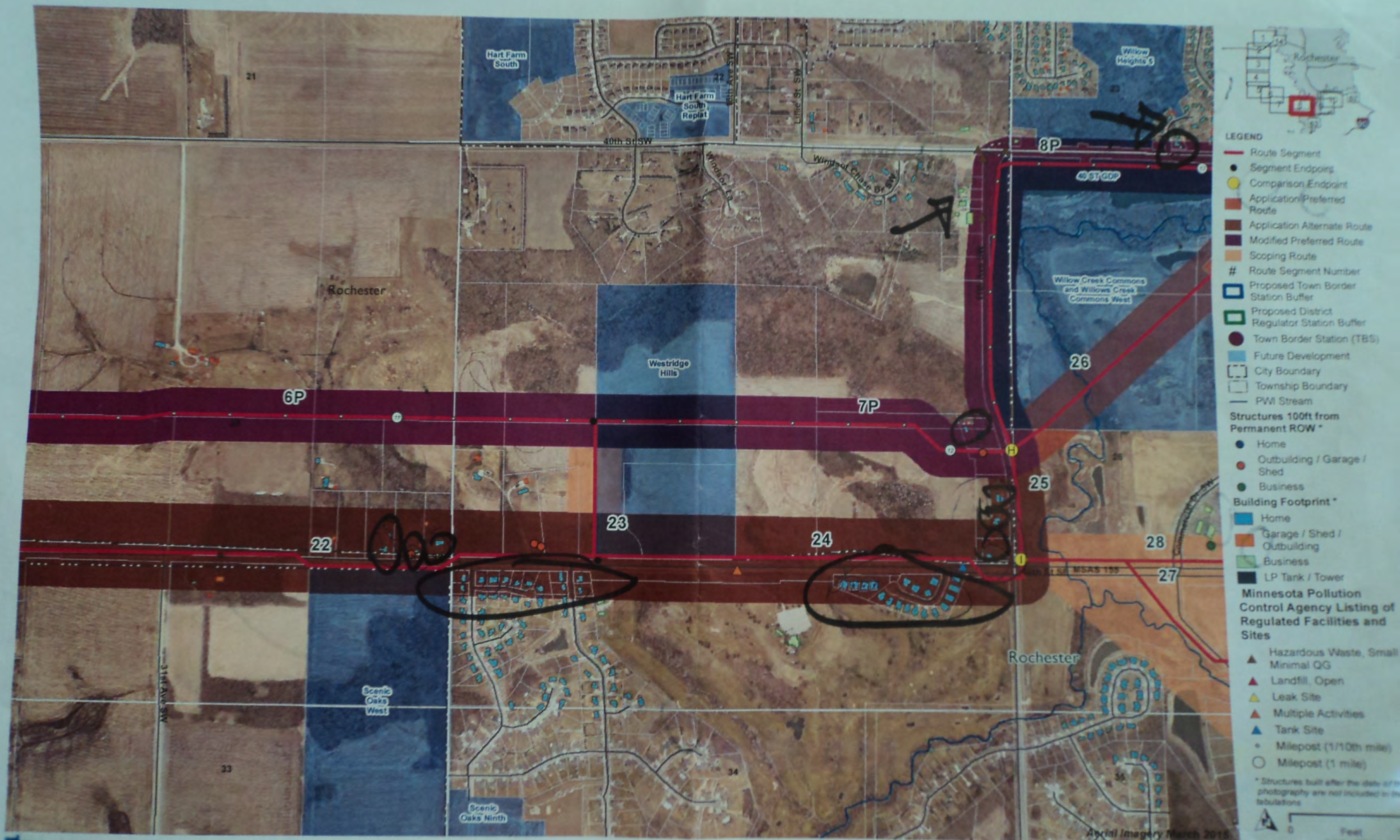
MINNESOTA DEPARTMENT OF COMMERCE

RESIDENCES, COMMERCIAL AND OUT BUILDINGS AND MINNESOTA POLLUTION CONTROL AGENCY LISTINGS

ROCHESTER NATURAL GAS PIPELINE

FIGURE 10 (PAGE 7 OF 10)

12+ purple 4 brown 2 orange 16+ Brown



MINNESOTA DEPARTMENT OF COMMERCE

30+ - brown 10+

RESIDENCES, COMMERCIAL AND OUT BUILDINGS AND MINNESOTA POLLUTION CONTROL AGENCY LIST

ROCHESTER NATURAL GAS PIP

FIGURE 10 (PAGE 8

MINNESOTA DEPARTMENT OF COMMERCE

RESIDENCES, COMMERCIAL AND OUT BUILDINGS AND MINNESOTA POLLUTION CONTROL AGENCY LISTIN

ROCHESTER NATURAL GAS PIPEL

FIGURE 10 (PAGE 9 O

RESIDENCES, COMMERCIAL AND OUT BUILDINGS AND MINNESOTA POLLUTION CONTROL AGENCY LISTI

ROCHESTER NATURAL GAS PIP

FIGURE 10 (PAGE 10 O

MINNESOTA DEPARTMENT OF COMMERCE