


Resource Plan

Great River Energy



GREAT RIVER
ENERGY®

A Touchstone Energy® Cooperative 

Maple Grove, MN

July 1, 2008

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EXECUTIVE SUMMARY

Introduction

Great River Energy (GRE) is a not-for-profit generation and transmission cooperative corporation providing wholesale electric service to 28 member electric distribution cooperatives, who provide retail service across a large part of Minnesota and a small part of Wisconsin. Our members serve some 631,000 loads that include residences and farms, commercial and industrial facilities, and other customers, representing approximately 1.6 million people in total. We are entirely owned by our members and are governed by a board of directors elected from among our members' boards, who in turn are elected by their own members, the end-use consumers.

GRE's mission is to provide our members with reliable energy at competitive rates in harmony with a sustainable environment. We strive to keep these three components, (1) competitive rates, (2) reliability and (3) environmental stewardship, as balanced objectives in the development and execution of our resource and other plans.

GRE's members currently have a peak demand of approximately 2600 MW. Ours is a summer peaking system that is highly weather-sensitive. Because of this, GRE and its members have implemented extensive load management programs to reduce the need for peaking capacity and conservation and energy efficiency programs to reduce the need for both capacity and energy.

GRE's supply portfolio consists of owned and purchased resources that utilize coal, natural gas, oil, wind, hydro, refuse-derived fuel, and methane energy.

GRE is a full member of the Midwest Independent Transmissions System Operator (MISO) system. GRE's resources and loads are part of the MISO market. GRE's transmission system is under MISO's operational control, with service provided pursuant to MISO's *Open Access Transmission and Energy Markets Tariff*.

GRE's most-recent prior resource plan filing was submitted on July 1, 2005. Since then,

- GRE and its member cooperatives have continued to promote load management conservation and efficiency programs and to increase those efforts as GRE's "First Fuel."
- GRE began receiving energy from the 100 MW Trimont wind farm in Martin and Jackson counties and the 100 MW Prairie Star wind farm in Mower County. GRE will begin receiving energy from the 99 MW Elm Creek wind farm, now under construction in Martin and Jackson counties, by the end of 2008.
- GRE placed in service a 154 MW peaking unit at Cambridge, Minnesota and began constructing a 175 MW peaking unit at Elk River, Minnesota.
- GRE withdrew from the Big Stone II power project.

- GRE completed turbine upgrades at one Coal Creek Station unit to increase its output and efficiency.
- GRE began constructing a combined heat and power project in Spiritwood, North Dakota that will ultimately provide 62 MW of baseload capacity and 37 MW of peaking capacity.
- Eight of our member cooperatives have elected to fix the amount of capacity and related energy that they purchase from GRE. Their future growth will be supplied by others.
- GRE constructed a new headquarters building that showcases energy efficient and environmentally sound building techniques.
- Minnesota enacted its 25% by 2025 Renewable Energy Standard and 1.5% Energy Conservation Policy Goal.
- Climate change has become an issue of increasing concern.
- Construction costs for all types of energy infrastructure have increased substantially.
- Fuel costs have increased and remain volatile.
- A slowdown in housing starts has decreased growth in our number of consumers, though the average use of electricity per consumer has increased.

Planning Process

We developed this resource plan using the following process:

1. We developed an econometric load forecast taking into account the current housing recession and the additional conservation and energy efficiency results needed to meet Minnesota's Energy Conservation Policy Goal. *Meeting this goal is a key assumption of this plan.*
2. We compared the load forecast with our existing resource portfolio to identify future shortfalls.
3. We identified generic resources available for future power supply, including renewables (exemplified by wind), peaking resources, intermediate resources, and baseload resources (including nuclear and advanced coal technologies both with and without CO₂ capture).
4. We developed a "benchmark" scenario and alternative scenarios in which we varied key assumptions such as CO₂ costs, natural gas costs, wind energy costs, and load growth.
5. We used a capacity expansion optimization model to develop resource plans for each scenario.
6. We examined the resource plans to gain insights for developing a preferred plan.

Although preparing this plan involved extensive analytics, we focused on making the plan more informative than definitive. Unlike other proceedings, such as Certificates of Need, that require black or white decisions, in a resource plan proceeding we have an opportunity to recognize the many shades of gray associated with how we should meet future electricity needs. We feel that this approach is appropriate in this time of great uncertainty about many of the key parameters that affect those choices.

Demand Side Resources

GRE and our member systems conduct an extensive set of load management and conservation / energy efficiency programs. In 2007, these programs saved 58 million kWh of energy and allowed GRE to eliminate the need for 200 MW of peaking capacity. In 2007, GRE spent nearly \$21 million on these programs, which is 166% of the statutory requirement.

With rising costs for new supply-side resources and increasing concern about CO₂ emissions and their future costs, we are expanding our commitment to conservation and energy efficiency, treating them as our “First Fuel”. We, in concert with our members, will strive to meet Minnesota’s 1.5% Energy Conservation Policy Goal, though we acknowledge that this will be a challenging endeavor. To help guide our program designs we conducted an energy conservation potential study through an outside consulting firm. In 2008 we are increasing our demand side program spending by 25%. Over the last three years we have more than doubled our energy efficiency rebate budget, created a department dedicated to energy conservation marketing communications, and established a zero-interest loan programs for energy efficient building design (\$20 million) and commercial energy efficient equipment (\$8 million). Our new headquarters building is a showcase of energy efficient design, intended to demonstrate what is possible using energy efficient technologies that are available today.

Supply-side Resources

GRE’s existing and committed resource mix consists of:

	MW
Coal-fired baseload	1530
Peaking	1360
Wind (nameplate)	316
Refuse-Derived Fuel	37
Landfill gas	3
Pipeline compressor heat recovery	7
Western Area Power Admin. allocations	90
Bilateral Transactions (net)	445

Although peaking resources (primarily combustion turbines fueled with natural gas and fuel oil) provide a significant and necessary portion of our capacity, they supply a relatively small amount of energy. Conversely, the wind resources are a significant source of energy, but provide a relatively small amount of capacity.

GRE is a full participant in the short-term energy markets operated by the Midwest Independent Transmission System Operator (MISO). All of GRE’s resources are offered into those markets and all of GRE’s members’ loads are served from them. Our resource portfolio provides a hedge against market prices. In effect, we still meet a significant portion of our members’ energy needs through our resource portfolio. But the MISO market provides access to a much

broader pool of economically-dispatched resources and economic management of transmission congestion.

We continually look for ways to improve our resources and to develop new opportunities, such as for combined heat and power projects that more effectively utilize thermal energy for multiple purposes. In 2008 we completed a turbine upgrade at Coal Creek station that increased its generating capacity with no additional fuel consumption. We have implemented programs to use waste heat and process steam from Coal Creek Station to provide energy to an adjacent ethanol plant and in a separate project to dry lignite, improving its energy content and reducing emissions. We actively market fly ash from our coal fired plants for use in the construction and oil field industries. Fly ash is a partial replacement for cement in concrete, reducing the CO₂ emissions associated with cement production.

We monitor a number of evolving environmental issues and regulations that may affect our existing resources and future opportunities. These include:

- greenhouse gas emissions,
- regional haze regulations,
- National Ambient Air Quality Standards,
- mercury reduction,
- Clean Air Interstate Rule,
- impaired waters and water discharge limits, and
- protecting aquatic life at cooling water intakes.

Of these, greenhouse gas emissions have the greatest potential impact on our operations and future resource choices. We have inventoried our greenhouse gas emissions and are a Founding Reporter of The Climate Registry. We are actively involved in CO₂ policy initiatives and research efforts at the federal and state levels. As discussed further below, we evaluated a wide range of CO₂ costs in developing this resource plan and will continue to do so as new information develops.

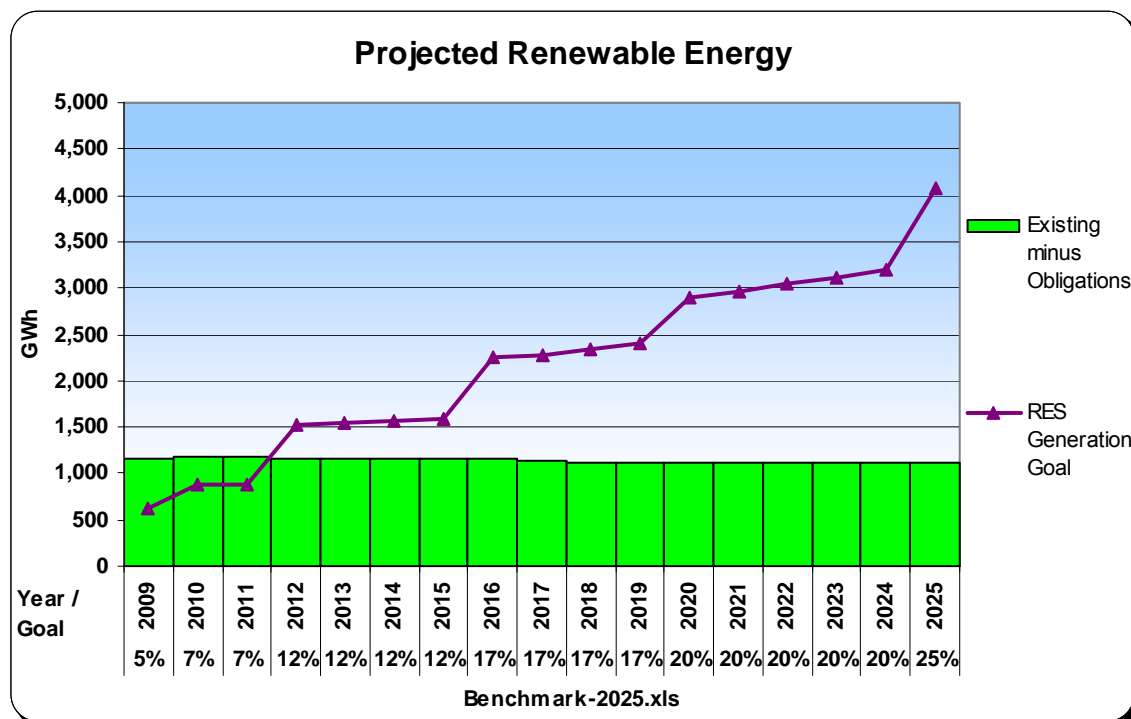
For capacity expansion modeling, we assumed that our existing plants would continue in service and that our transactions would end at the expiration of their terms. We then allowed our capacity expansion optimization model to select additional resources from among a menu of generic resource types, including renewables (exemplified by wind), peaking resources, intermediate resources, and baseload resources (including nuclear and advanced coal technologies both with and without CO₂ capture).

Renewable Resources

GRE has added renewable resources well ahead of the requirements of the Minnesota Renewable Energy Objective. We currently have approximately 216 MW of wind resources under contract, with another 99 MW under construction. We generate electricity from refuse-derived fuel at our 37 MW Elk River Station plant. We purchase energy from a 3 MW landfill

gas generator in Elk River and two dairy farms with anaerobic digester projects. GRE has installed a 200 kW wind generator and a 72 kW photovoltaic system at its new headquarters building in Maple Grove. In addition, our members purchase energy from a number of distributed generation projects that are connected to their distribution systems. These include landfill gas, small wind, and photovoltaic generators.

The figure below shows our current status with respect to Minnesota Renewable Energy Objective / Standard. GRE is better than 2/3 of the way to meeting the 2012 standard of 12%. GRE will require about another 1000 MW of nameplate wind capacity by 2025 to meet the 25% RES standard, if entirely met with wind.



The primary obstacles we see in meeting the RES are:

- transmission, including
 - delays and uncertainties in the MISO generator interconnection queue, which is currently “choked” with proposed projects;
 - a strong need for additional transmission capacity to allow wind resources to reach loads; and
 - “pancaked” transmission charges for wind projects that deliver energy into MISO from projects connected to non-MISO transmission providers;
- equipment supplies and costs, especially for wind turbines;
- federal Production Tax Credit renewal uncertainties;
- uncertainties about the long-term reliability and maintenance costs of wind farms; and
- the need to renegotiate or replace our wind power purchase agreements as they eventually expire.

These obstacles are not unique to GRE and are being addressed regionally and industry-wide. For example, MISO is addressing the generator interconnection queue issues through a reformed process that it has proposed to the Federal Energy Regulatory Commission. Future transmission needs are being addressed through CapX 2020's transmission proposals and through additional studies by MISO, the CapX 2020 utilities, and Minnesota transmission providers in conjunction with other stakeholders. We are participating in developing these solutions. We are also investigating additional actions such as adding energy storage (both utility-scale, such as batteries and pumped hydro and customer-scale, such as storage space and water heating), taking an ownership position in a portion of our renewable portfolio, and developing other renewable resources such as biomass and anaerobic digesters.

Community-Based Energy Development (C-BED) projects have been encountering many of the same obstacles noted above, which are not unique to their C-BED status. Many of the solutions, if successful, will be beneficial to C-BED projects.

Transmission

GRE owns over 4000 miles of high voltage transmission facilities. Because of intertwined service territories, many of our member systems' loads are served by transmission facilities owned by other utilities and vice versa. GRE and those utilities have turned functional control of most of their transmission facilities over to MISO, which provides service through a common tariff. A few pre-MISO agreements remain in effect, dealing with transmission arrangements for GRE's North Dakota generating assets and transactions with Manitoba Hydro.

Although the regional transmission system is generally adequate to meet current needs, expansion will be critical to meet future load growth and to support increasing development of energy resources such as wind that are distant from load centers.

The electric grid is heavily interconnected and must be evaluated, operated, and expanded in a coordinated manner to assure reliability and cost-effectiveness. GRE's transmission planning is closely coordinated with other organizations, including MISO, the Midwest Reliability Organization (MRO), the Minnesota Transmission Owners (MTO), CapX 2020, Subregional Planning Groups (SPGs), and the Mid-Continent Area Power Pool (MAPP).

CapX 2020, a joint initiative of eleven regional transmission utilities, is developing long range plans and coordinating the development of specific projects to address "backbone" transmission needs in and around Minnesota. The first phase of projects includes 345kV transmission lines from the Twin Cities to North Dakota, South Dakota, and Wisconsin and a 230kV line between Bemidji and Grand Rapids, Minnesota.

GRE's transmission plans have been reported in

- the Minnesota Transmission Owners 2007 *Biennial Transmission Report and Renewable Energy Standards Report*, and
- the MISO 2007 *Transmission Expansion Plan* (MTEP-07).

The transmission system and the issues surrounding its use and expansion are exceedingly complex. Some significant issues include:

- reforming the generator interconnection process to provide more certainty about timing and costs;
- developing a cost allocation mechanism for transmission projects that cross multiple rate zones and serve multiple purposes; and
- assuring that adequate transmission will be available to reliably meet the Minnesota Renewable Energy Standard.

GRE is involved in addressing these issues through the various organizations noted above.

Capacity Expansion Modeling

We used a commercially-available capacity expansion optimization program, Ventyx CEM, for our modeling, with the following assumptions:

1. No interactions with the short-term energy market (a self-sufficient perspective).
2. CO₂ costs were examined ranging from \$0 per ton of CO₂ to \$4, \$10, \$30, \$50, and \$70. These values are in 2008 dollars per short ton and were escalated at 3% per year. CO₂ costs were assumed to begin immediately. In scenarios involving CO₂ values greater than \$10 per ton, \$10 (escalating) was used through 2012 and the higher values thereafter.
3. Fuel costs were developed by GRE for coal and an outside advisor, Ventyx, for oil and natural gas. Expected and high natural gas prices were studied.
4. The federal Production Tax Credit (PTC) is extended under its existing terms (escalating) through 2012.
5. In most scenarios, the Minnesota Renewable Energy Standard was a floor to the amount of wind resources added. The model was allowed to select more wind if economical.
6. Existing resources remain in service through the study period, even though at high CO₂ costs baseload coal units shift to cycling operation, which may result in additional unrecognized costs for modifications, retirements, repowering, or retrofitting for CO₂ capture.
7. Contracts for resources, both purchases and sales, expire at the end of their terms.
8. In most of the scenarios, the load forecast reflects meeting Minnesota's 1.5% Energy Conservation Policy Goal without identifying specifically how it would be met nor what costs may be incurred in doing so.
9. No price-demand elasticity was included due to the complex interplay of changes such as CO₂ costs on other fuels, other uses of energy, housing patterns, and the economy in general.

We developed a Benchmark scenario that assumed a 2008 value of \$10/ short ton of CO₂, and expected values for other assumptions. We compared the benchmark to 16 other scenarios involving variations in CO₂ costs, gas prices, wind resource costs, load, and Renewable Energy Standard compliance.

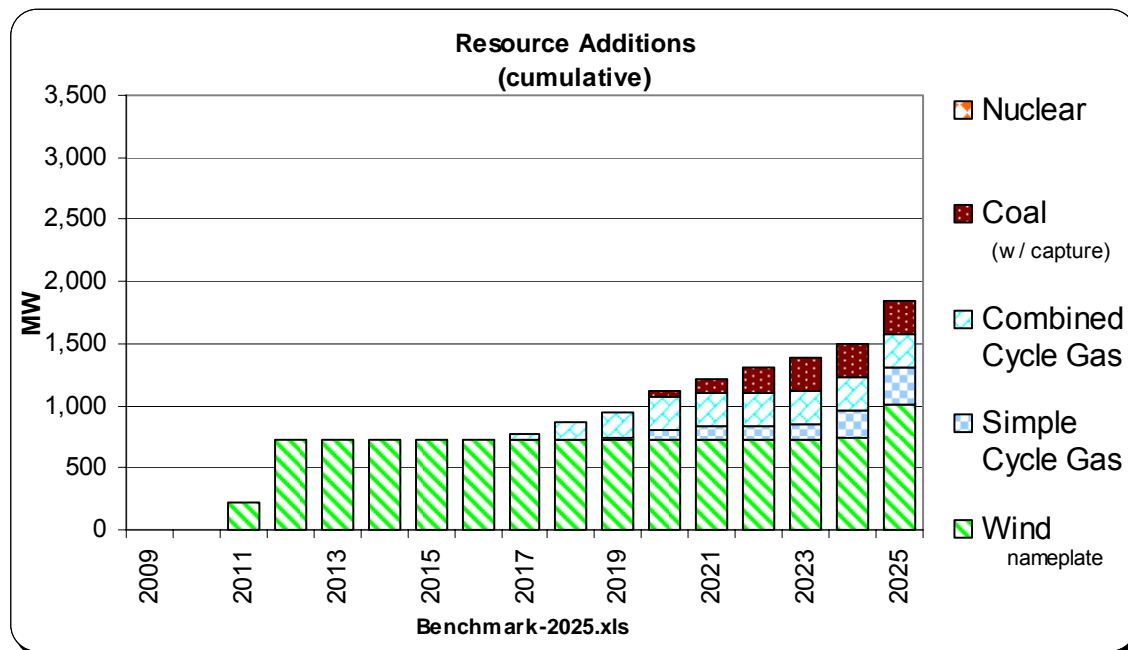
Conclusions from Modeling

Our capacity expansion modeling supports the following conclusions:

- Wind and gas resources (simple cycle or combined cycle combustion turbines) should suffice for the first ten years of the planning period; additional baseload resources will be needed in the 2020 timeframe.
- The optimal amount and timing of wind resources is very sensitive to the cost of wind energy, especially the Production Tax Credit.
- GRE's large fleet of modern gas fired peaking units has relatively flexible operating characteristics that can be used to accommodate the intermittency of additional wind resources.
- No new coal is selected before 2020 unless either the Renewable Energy Standard or the Minnesota 1.5% Energy Conservation Policy Goal is not met. In any scenario with carbon costs of \$10/ton or higher the only coal resources selected are those that include carbon capture.
- At high CO₂ costs (greater than \$30/t):
 - existing coal plants are no longer baseloaded, suggesting a need to modify them for cycling operation, retire or repower them, or add carbon capture;
 - nuclear or coal w/ carbon capture become more cost effective than natural gas; and
 - costs (and therefore rates) increase dramatically unless offset by emission allowances or some other form of credits.
- Although in various scenarios the model selects nuclear or coal with carbon capture to meet long-term baseload needs, there is no obvious "winner". Nuclear, coal with carbon capture, or other baseload resources with low or no CO₂ emissions (such hydro) remain candidates.

Resource Plan

The following chart shows our preferred resource plan, which is based on \$10/ton CO₂:



In the next five years, the only resource additions indicated in the preferred plan are wind. Since there is no assurance that the federal Production Tax Credit will be extended indefinitely, there is an incentive to acquire wind resources ahead of our needs.

We will need additional natural gas fired generation around the 2017 timeframe. No commitment decision is necessary now since such resources have relatively short lead times, although we will continue to develop options. The specific timing and types of these additions (simple cycle or combined cycle) will depend on market conditions, fuel costs, and the pace of demand and energy growth.

We will need additional low/no carbon baseload resources around 2020. There is enough uncertainty about the costs and future availability of resources such as nuclear and advanced coal with carbon capture that there is no clear choice at this time. Since any of these alternatives involve significant challenges and long lead times, early work to develop options is appropriate.

Our Plan is in the Public Interest

GRE is committed to providing reliable energy at competitive rates and to do so in harmony with a sustainable environment. We have kept that commitment to our members and to the public in developing this resource plan by:

- making conservation and energy efficiency our “first fuel” in helping consumers make the most of the energy they use and thereby reduce our need for new supply-side resources;
- working to improve the efficiency of our existing resources;
- continuing to meet much of our future energy requirements with renewable resources;
- evaluating a set of indicative future resource options using capacity expansion modeling under multiple scenarios that included, among other things, a wide range of possible future CO₂ costs; and
- developing a plan that maintains flexibility to adjust for new information and changing circumstances.

1 INTRODUCTION

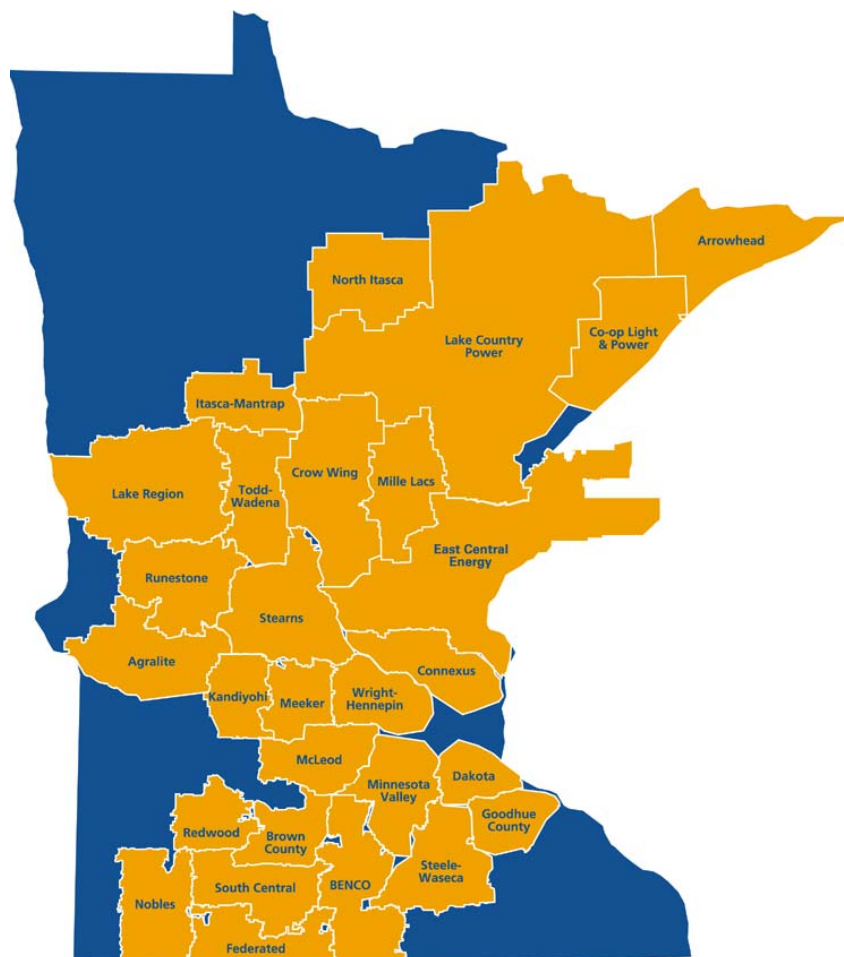
1.1 Great River Energy Overview

1.1.1 Our Business

GRE is a not-for-profit, electric generation and transmission cooperative corporation formed to provide wholesale electric service to 28 member electric distribution cooperatives. The services GRE provides include:

- procuring energy resources, either through the ownership of generation facilities or by obtaining contractual rights to energy from other suppliers, to meet all or a portion of our members' energy requirements;
- delivering energy to our members through our transmission facilities or through arrangements with other utilities; and
- other energy-related services, such as coordination of conservation and demand-side management programs, to achieve scale economies.

GRE is entirely owned by our members, who distribute electricity to approximately 631,000 consumers that include residences and farms, commercial and industrial facilities, and other customers, representing a total of approximately 1.6 million people across a large part of Minnesota and a small part of Wisconsin (see Figure 1-1). GRE is governed by a board of directors elected from among our members' boards, who in turn are elected by their members, the end-use consumers.

Figure 1-1 GRE Members' Service Territories

Twenty of GRE's members receive all of their requirements from GRE and will continue to do so under long-term contracts. Two of GRE's members (designated as "Fixed" in Figure 1-2) have chosen to fix the amount of capacity and associated energy that they receive from GRE at 2006 levels. Six other members (designated as "Fixing" in Figure 1-2) have elected to similarly fix the capacity and energy they receive from GRE at 2007 or 2008 levels. Resources to serve the future growth of these eight members will be supplied by others and are not included in this resource plan. GRE will continue to provide transmission service for the entire needs of all of our members.

Figure 1-2 GRE Members' Service Status

Member	Location	Status
Agralite Electric Cooperative	Benson, MN	Fixing
Arrowhead Electric Cooperative, Inc.	Lutsen, MN	All-req.
BENCO Electric Cooperative	Mankato, MN	All-req.
Brown County Rural Electric Assoc.	Sleepy Eye, MN	All-req.
Connexus Energy	Ramsey, MN	All-req.
Cooperative Light & Power	Two Harbors, MN	All-req.
Crow Wing Power	Brainerd, MN	Fixing
Dakota Electric Association	Farmington, MN	All-req.
East Central Energy	Braham, MN	All-req.
Federated Rural Electric Assoc.	Jackson, MN	Fixing
Goodhue County Cooperative Electric	Zumbrota, MN	All-req.
Itasca-Mantrap Cooperative Electrical Assoc.	Park Rapids, MN	All-req.
Kandiyohi Power Cooperative	Willmar, MN	All-req.
Lake Country Power	Grand Rapids, MN	All-req.
Lake Region Electric Cooperative	Pelican Rapids, MN	All-req.
McLeod Cooperative Power Assoc.	Glencoe, MN	All-req.
Meeker Cooperative Light & Power Assoc.	Litchfield, MN	Fixing
Mille Lacs Energy Cooperative	Aitkin, MN	All-req.
Minnesota Valley Electric Cooperative	Jordan, MN	Fixed
Nobles Cooperative Electric	Worthington, MN	All-req.
North Itasca Electric Cooperative, Inc.	Big Fork, MN	All-req.
Redwood Electric Cooperative	Clements, MN	Fixing
Runestone Electric Association	Alexandria, MN	All-req.
South Central Electric Association	Saint James, MN	Fixing
Stearns Electric Association	Melrose, MN	All-req.
Steele-Waseca Cooperative Electric	Owatonna, MN	All-req.
Todd-Wadena Electric Cooperative	Wadena, MN	All-req.

Member	Location	Status
Wright-Hennepin Cooperative Electric Assoc.	Rockford, MN	Fixed

1.1.2 Our Values

GRE's mission is to provide our members with reliable energy at competitive rates in harmony with a sustainable environment. We strive to keep these three components, (1) competitive rates, (2) reliability and (3) environmental stewardship, as balanced objectives in the development and execution of our plans.

Competitive Rates

We consider the impact on our rates to our members in making any material business or operational decision. As a not-for-profit cooperative, we were formed to provide reasonably priced wholesale electric services to our members.

Reliability

Our ability to reliably serve our members depends on the efficient operation of our generation and transmission facilities. In evaluating potential investments to our system, we weigh reliability considerations against the relative cost savings of any option. In addition, we have made and expect to continue to make substantial capital expenditures in our generation and transmission facilities in an effort to maintain and enhance our system's future efficiency and reliability.

Environmental Stewardship

We have taken substantial steps to mitigate the impact of our operations on the environment. Our efforts to enhance our environmental stewardship include purchasing energy from renewable sources, operating our facilities in accordance with certified environmental management systems, investing in emission controls and developing commercial uses for our facilities' by-products.

As fuel and new infrastructure costs rise and concerns about carbon dioxide and other emissions increase, GRE is emphasizing conservation and energy efficiency as a strategic imperative, treating them as our "first fuel". An underlying assumption in this resource plan is that GRE and its members will meet the 1.5% Energy Conservation Policy Goal established by the Minnesota Legislature in 2007.

1.2 Developments since GRE's Last Resource Plan

GRE's last resource plan filing was submitted on July 1, 2005 (Docket ET2/RP-05-1100). It called for more peaking and intermediate resources in 2008-2010, additional baseload resources in 2014-2016, and renewable resources (represented by wind) added in blocks throughout the period covered by the plan.

The following developments subsequent to that filing are notable:

- The Midwest ISO energy market was launched (April 1, 2005) just prior to GRE's last filing, with all of GRE's resources being sold into that market and all of GRE's load being

served from it. The market continues to evolve with expected start up of the Ancillary Services Market in the near future.

- GRE placed in service a 154 MW peaking unit at Cambridge, Minnesota and began constructing a 175 MW (summer rating) peaking unit at Elk River, Minnesota.
- GRE began receiving energy from the 100 MW Trimont wind farm and the 100 MW Prairie Star wind farm. GRE will begin receiving energy from the 99 MW Elm Creek wind farm, now under construction, by the end of 2008.
- GRE withdrew from the Big Stone II power project.
- GRE began constructing a combined heat and power project in Spiritwood, North Dakota that will ultimately provide approximately 62 MW of baseload capacity and 37 MW of peaking capacity.
- GRE completed turbine upgrades at one Coal Creek Station unit to increase its efficiency
- GRE and its member cooperatives have continued to promote load management conservation and efficiency programs and to increase those efforts as GRE's "First Fuel."
- In 2007, Minnesota enacted a 25% by 2025 Renewable Energy Standard (Minn. Stat. §216B.1691) and a 1.5% Energy Conservation Policy Goal (Minn. Stat. §216B.2401).
- Climate change has become an issue of increasing concern.
- Construction costs for all types of energy infrastructure have increased substantially.
- Fuel costs have increased and remain volatile.
- A slowdown in housing starts has decreased growth in our number of consumers, though the average use of electricity per consumer has increased.
- Eight of our member cooperatives have elected to fix the amount of capacity and related energy that they purchase from GRE.
- GRE constructed a new headquarters building that is intended in part to showcase energy efficient and environmentally sound building techniques.

2 PLANNING PROCESS

This section outlines GRE's process for developing a preferred resource plan and resulting action plan(s). Greater detail on each of the items is included in subsequent sections of this document.

2.1 Overview

1. We developed a system-level econometric load forecast that takes into account the recent housing recession. This forecast was adjusted to account for the additional conservation needed to meet Minnesota's energy conservation policy goal. (See *Section 3 and Appendices A and B*).
2. We compared the load forecast with our existing resource portfolio to identify future shortfalls. (See *Sections 4 and 6*).
3. We identified a list of generic resources available for future power supply. (See *Section 7 and Appendix E*).
4. We developed a set of base assumptions for a "benchmark" scenario which could be modeled and compared with alternative scenarios having differing assumptions. (See *Section 8*)
5. We modeled the benchmark and alternative scenarios using a capacity expansion optimization model. (See *Section 8 and Appendix C*)
6. We examined the scenarios to identify commonalities and differences in the resources added. (See *Section 8 and Appendix C*).
7. We used this examination of scenarios as a guide to formulate a preferred resource plan. (See *Sections 8 and 10 and Appendix C*).

2.2 Differences from 2005 Filing

In addition to the situational differences described in Section 1.2, this resource plan involves several process differences from GRE's prior resource plan filing of July 1, 2005 (Docket No. ET2/RP-05-1100):

- GRE acquired capacity expansion modeling software and the capability to use it "in house". Rather than study predetermined expansion plans, the capacity expansion model develops optimal (least cost) expansion plans for each scenario studied.
- All future resources are generic. Only existing and committed resources are represented explicitly in the modeling.
- A range of CO₂ costs well beyond statutory requirements was considered.

2.3 Compliance References

The Commission's August 4, 2006 dispositive order regarding the 2005 resource plan (Docket No. ET2/RP-05-1100) and its order issued October 31, 2007 (same docket number) granting a change in filing date following GRE's withdrawal from the Big Stone II project contained numerous requirements and suggestions for this resource plan. The points of those Orders and GRE's compliance actions are listed in Section 11.1 of this plan.

The relevant requirements of Minnesota statutes and rules are listed in Sections 11.2 and 11.3 with cross references to locations in this resource plan or filings in other dockets that address those requirements.

2.4 Trade Secret Information

Only Appendices D and E contain trade secret information.

3 LOAD FORECAST

This section describes GRE's 2008 system energy and demand forecasts.

3.1 Overview

GRE recently completed a 2006 Long Range Load Forecast (LRLF) that involved an intensive effort to remove the effects of DSM programs from historical load data and use the resulting series as the basis for forecasting. However, as 2007 load data became available, it became apparent that this forecast was too high in the early years because of the current housing recession and deteriorating economic conditions. The number of residential consumers added during 2007 was well below forecast levels and 2008 did not look any better for housing growth. The effects of the housing recession are large enough that we did not want to use the 2006 LRLF as the basis for our resource planning efforts. Instead, we developed a system-level econometric forecast of energy and demand using the methodology described below.

3.2 Forecast Methodology

During 2008, we prepared a monthly econometric forecast of GRE demand and energy for use in a Monte-Carlo exploration of the probability of exceeding various forecast load levels. It was named the "2008 Exploratory Risk Analysis Econometric Model" (ERAEM).

The 2008 ERAEM turned out to be very good statistically. We accounted for the housing recession and economic slowdown by assuming that the very low residential consumer growth rate in 2007 would continue through 2008 and partly through 2009, after which growth would return to the amounts forecast in the 2006 LRLF.

In the resulting forecast, the summer season demand forecast starts out substantially lower than the 2006 LRLF but grows faster. In the tenth year they are approximately the same as forecasted in the 2006 LRLF. Thus for the critical first decade of planning, resource requirements are lower using the 2008 forecast.

The result of the econometric model is a forecast of monthly system demand and energy. We then developed a Monte-Carlo model and used it to calculate 50% and 90% probable levels of system seasonal summer peaks¹.

¹ The seasonal system peaks calculated by the Monte Carlo model are higher than the individual months' peak forecast by the econometric model. The Monte Carlo model forecasts higher peaks because it uses the variability of weather in both July and August to forecast a seasonal peak. The probability of experiencing hotter than normal weather is greater when looking at the season as a whole. Where as the monthly model uses the variability of weather in each specific month to forecast the likely peak in each individual month.

3.2.1 Conservation in the 2008 ERAEM

GRE has had extensive conservation programs underway since 1980. Our historical load data reflects the effects of those conservation programs. When this historical data is used in an econometric model, the forecast reflects a continuation of conservation programs proportional to historical programs. The forecast is an “embedded conservation” forecast. Because of this, it is not correct to subtract out the entire effect of future additional conservation programs. Only greater than proportional (trend) conservation efforts can properly be subtracted.

To provide the numbers needed to adjust the 2008 ERAEM forecast for greater-than-historical conservation embedded, a trend forecast of conservation was needed. Energy conservation estimates from 2004 to 2007 were used to calculate the trend. We recognize that using such a short series of estimated data for a long-term forecast introduces uncertainty. Despite that uncertainty it was necessary to restrict the analysis to that data because data before 2004 was not available.

We assumed that the demand effects are proportional to the energy effects. This is an assumption that new energy-conserving appliances are used like the average appliances on the GRE system.

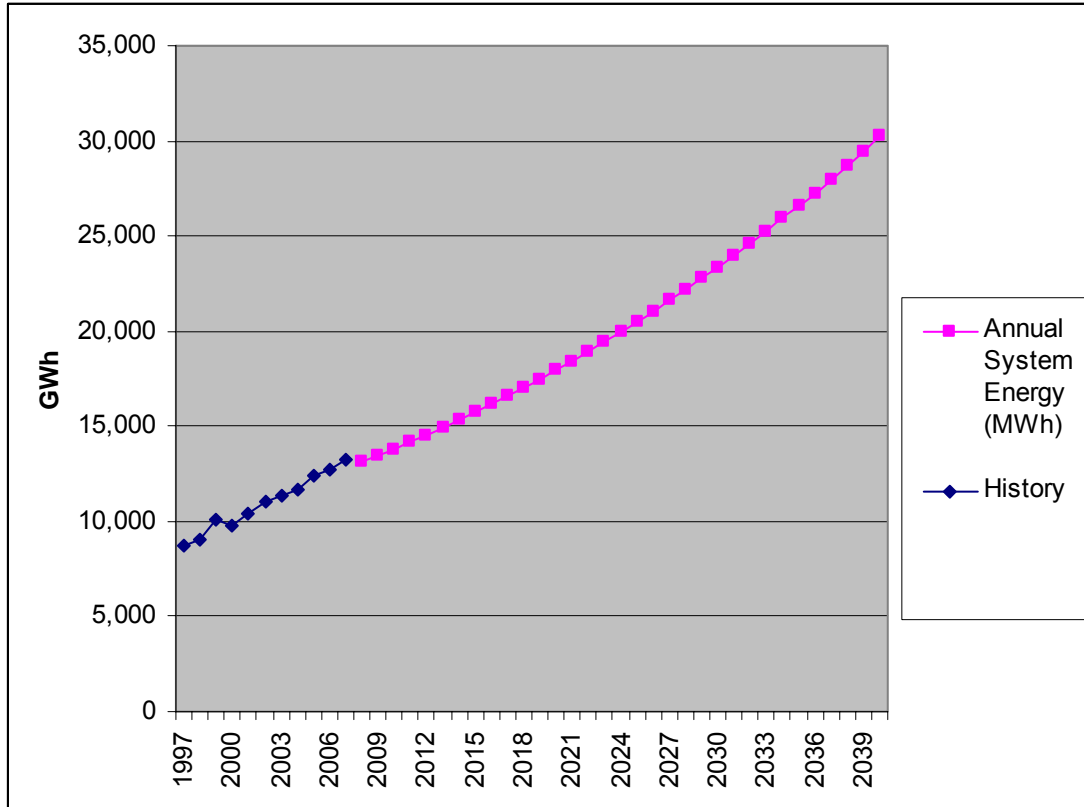
See Appendix B for the detailed adjustments to the forecast for the effects of conservation.

3.3 Forecast

Following is a summary of the demand and energy forecasts used in this resource plan as a base case. These figures include the total load of all of GRE’s member cooperatives, including those that are taking fixed requirements service rather than all requirements service. The fixed requirements members are accounted for in this resource plan by adding unspecified “fixing growth” resources that will be supplied by others rather than by subtracting the growth of those members from the load forecast. As noted above, these forecasts reflect embedded conservation at historical levels. Forecasts with additional conservation to meet the Minnesota 1.5% Energy Conservation Policy Goal are documented in Appendix B.

System Energy

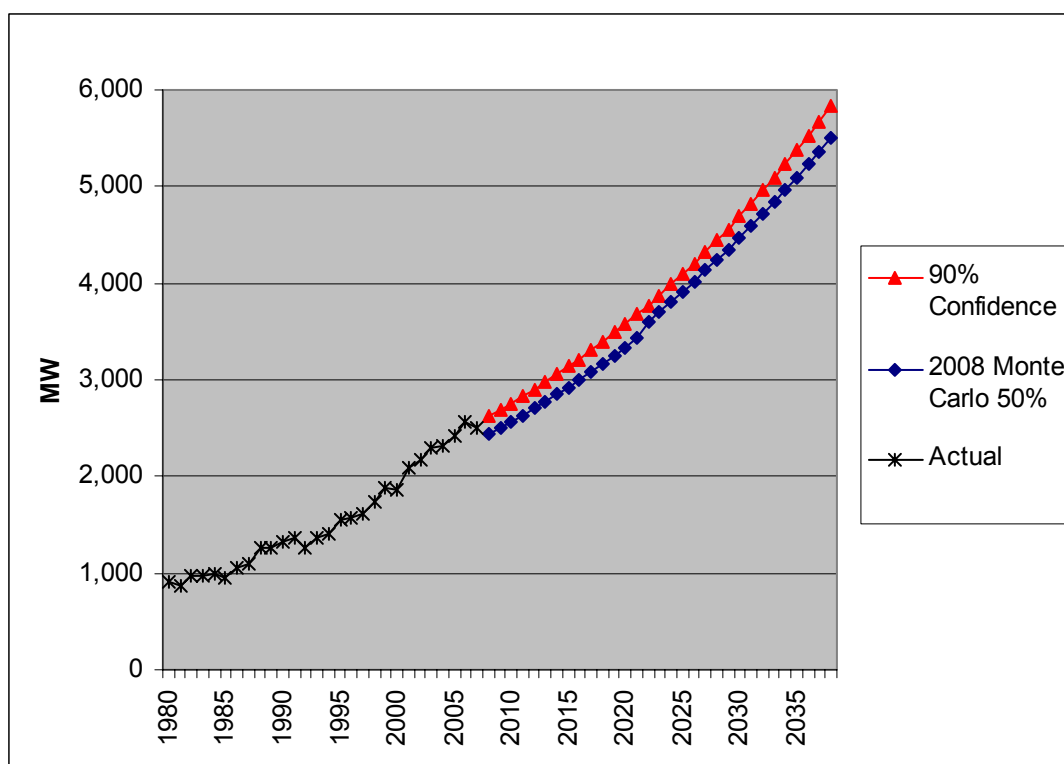
Figure 3-1 2008 ERAEM Energy Forecast



System Demand

GRE uses a 90% probability forecast for long-range capacity planning purposes². We feel that planning to this level is prudent and reflects a level of risk acceptable to our members. Figure 3-2 shows the 90% demand forecast that we used for capacity planning and the 50% demand forecast that corresponds to our 50% probability energy forecast.

Figure 3-2 Comparison of the 2008 ERAEM Monte Carlo Seasonal Demand and 2008 ERAEM 90% Confidence Demand Forecast Results



² This 90% probability forecast has been called "Scenario 5" in past GRE resource plans.

3.4 Space Heating Uncertainties

The electricity price increases of the 1980s virtually eliminated uncontrolled space heat loads from the GRE system. Eliminating those winter loads along with the increasing desire for air conditioning has made GRE increasingly summer peaking. The recent run up in the prices of fuels used for residential space heating has provided a direct incentive for customers to choose electricity for space heating once again. While it doesn't appear that we are in immediate danger of becoming winter peaking and having the winter peak demand drive the need for additional capacity, space heating loads tend to have a much higher load factor than other types of load (like air conditioning) and may drive the need to adjust the resource mix even if no additional capacity is needed in the short run.

4 EXISTING AND COMMITTED RESOURCES

4.1 Existing Demand Side Resources

4.1.1 Existing Load Management, and Conservation and Energy Efficiency Programs

GRE's conservation and energy efficiency programs are designed to assist and educate member cooperatives and their customers. The programs provide incentives such as rebates, low-to-zero interest loans, and conservation education to help reduce energy consumption and costs. GRE promotes these programs and provides the member cooperatives assistance in implementing the programs.

Conservation and energy efficiency programs can be broadly broken into two categories. The first is indirect conservation. These are programs that educate and inform customers of ways to conserve energy, but are not always quantifiable. Some examples include: providing conservation-related bill stuffers, handouts, and newsletter articles; educating customers to plant trees near their homes to provide summer shade and keep blinds open in the winter to allow for the solar effect; and encouraging customers to conduct self-driven home energy audits.

The second category is direct energy conservation. These programs have quantifiable energy and/or capacity savings. Examples of these are air source or ground source heat pumps, high-efficiency appliances, premium efficiency motors, variable speed drives and high efficiency lighting.

GRE's load management programs are designed to allow GRE to remotely control connected end-use loads during periods of high demand. Common examples are cycled air conditioning, controlled irrigation, off-peak water heating and interruptible commercial and industrial loads. A detailed description of each program can be found in the Conservation Improvement Program (CIP) report filed June 2, 2008 (Docket No. 08-254).

Generally GRE's conservation and energy efficiency programs decrease energy (i.e. MWh) use while load management emphasizes lowering the peak demand (i.e., MW). The increased efforts by GRE and the member cooperatives to focus on energy conservation (i.e., MWh) can be illustrated in several manners:

- An increased energy efficiency rebate budget, which was 3 million dollars in 2005, is now over 7 million dollars in 2008
- The addition of a Marketing Communications department at GRE which is responsible for developing GRE's energy conservation marketing communication strategies
- The development of a \$20 million dollar energy efficient building design zero interest loan program based on the Leadership in Energy and Environmental Design (LEED) program parameters.

- The development of an \$8 million dollar commercial energy efficient equipment (3E) zero interest loan program

These substantial changes are a result of GRE and member cooperatives continuing recognition of the economic value of cost-effective conservation and energy efficiency.

Figure 4-1 illustrates that GRE and the member cooperatives exceed the mandated minimum spending on load management and conservation programs. The reported energy and demand savings realized from the conservation and energy efficiency programs is detailed in the next section.

Figure 4-1 GRE and Member Cooperative Spending vs. Mandated Minimum Spending

GRE and Member Cooperative Spending vs. Statutory Minimum Spending						
	2005	2006	2007	2008 Plan	2009 Plan	2010 Plan
Total Minimum Requirement	\$12,548,011	\$12,548,011	\$12,548,011	\$14,174,735	\$14,174,735	\$14,174,735
Minimum Requirement Conservation	\$6,274,006	\$6,274,006	\$6,274,006	\$7,087,368	\$7,087,368	\$7,087,368
Minimum Requirement Load Management	\$6,274,006	\$6,274,006	\$6,274,006	\$7,087,368	\$7,087,368	\$7,087,368
Actual or Planned Expenditures						
Conservation Programs	\$8,804,999	\$7,107,678	\$8,569,956	\$11,003,628	\$12,497,203	\$13,737,013
DSM Programs	\$9,006,082	\$11,087,258	\$12,302,569	\$15,205,865	\$12,651,867	\$12,432,853
	\$0	\$0	\$0	\$0	\$0	\$0
Total Spending	\$17,811,081	\$18,194,936	\$20,872,525	\$26,209,493	\$25,149,070	\$26,169,866
Spending as a Percent of Mandated Requirement	142%	145%	166%	185%	177%	185%

4.1.2 Impact of Existing Conservation, Energy Efficiency, and Load Management Programs

Because GRE's customer base is largely residential (nearly 60% of 2007 energy sales) the daily load curve is primarily influenced by residential usage. GRE's load curve experiences two peaks, one in the morning and another occurring sometime between mid-afternoon and early evening. The afternoon peak constitutes the daily peak.

To improve its load factor, GRE has encouraged cost-effective load management and energy conservation programs that help to flatten the load curve, particularly in the summer months. Summer programs that reduce demand during peak periods include cycled air conditioning and air source heat pumps, controlled irrigation, off-peak water heating, and interruptible commercial and industrial programs. Through these efforts GRE has been successful in controlling demand the approximant equivalent of a 200 MW power plant. Reducing peak demands through load control helps to reduce GRE's need to build additional peaking resources. GRE also estimates that its conservation improvement programs in 2007 resulted in a total energy savings of approximately 58 million kWh.

Figure 4-2 summarizes the estimated capacity and energy savings of GRE's load management and energy conservation programs³. The savings includes distribution and transmission losses and the MAPP 15% reserve requirement.

Figure 4-2 2007 Load Management and Conservation Summary

Load Management and Conservation Summary		
Year	Summer Capacity Reduction (kW)	Annual Energy Savings (kWh)
2002	271,247	20,851,791
2003	331,073	39,516,243
2004	345,962	30,842,222
2005	364,000	29,299,610
2006	384,000	32,076,202
2007	360,000	58,060,845
2008 Plan	380,000	77,429,381
2009 Plan	400,000	127,188,900
2010 Plan	420,000	167,574,462

4.2 Existing and Committed Supply Side Resources

Following is a summary of GRE's existing generators and major transactions.

Figure 4-3 Simplified GRE Capacity Resources and Current Summer Accredited Rating in 2008

Unit Name	Capacity MW
Pleasant Valley Station (Peaking)	414.9
Lakefield Junction (Peaking)	497.0
Cambridge CT (Peaking)	21.1
Cambridge CT2 (Peaking)	154.3
Maple Lake CT (Peaking)	19.4
Rock Lake CT (Peaking)	19.8
St. Bonifacius CT (Peaking)	56.2

³ The capacity reduction shown is at the time of what would otherwise be the system peak. At other times, less load may be controllable. To minimize impacts on program participants, GRE may elect not to fully exercise its ability to control loads if sufficient peaking capacity is available. To conservatively allow for these factors, GRE uses a lower capacity reduction estimate for resource planning purposes, for example 200 MW in 2008.

Elk River Station 1 (RDF)	10.1
Elk River Station 2 (RDF)	10.5
Elk River Station 3 (RDF)	16.2
Stanton Station (Coal)	188.3
Stanton Station diesel	1.0
Coal Creek Station 1 (Coal)	548.4
Coal Creek Station 2 (Coal)	573.0
Coal Creek Station diesel	2.1
Chandler Wind (6 MW)	0.3
McNeilus Wind (6 MW)	0.3
Christoffer Wind (6 MW)	0.4
Trimont Wind (100 MW)	12.0
Prairie Star Wind (100 MW)	12.0
Total:	2553.3
Major Purchases	Capacity MW
Genoa 3 (Share of coal plant)	169.9
Western Area Power Administration	89.8
Manitoba Hydro Diversity Exchange	150.0
Manitoba Hydro capacity and energy	50.0
Minnesota Power Block A & B	175.0
NSP/Dynegy (ends in 2008)	150.0
Total Major Purchases:	784.7
Major Sales	Capacity MW
Willmar	30.0
NSP (Diversity Exchange)	50.0
Total Major Sales:	80.0

These ratings are for 2008 and they will vary from year to year based on annual performance testing. Trimont and Prairie Star wind have not been operating long enough to establish a capacity rating so 12 MW is assumed based on expectations. All existing GRE wind projects are purchased from developers. The purchases and sales represent the larger transactions for the summer 2008. They may change seasonally.

4.2.1 Existing and Committed Fossil-Fuel Resources

GRE's existing fossil-fuel resources can be characterized as baseload or peaking resources.

4.2.1.1 Existing Baseload Resources

GRE's existing base load generators include the 188 MW Stanton Station and the 1,121 MW Coal Creek Station. Both are located in central North Dakota. Stanton Station switched to Powder River Basin subbituminous coal (PRB) from lignite in November 2004. Coal Creek Station uses lignite coal from the adjacent Falkirk mine.

4.2.1.2 Existing Peaking Resources

GRE's major peaking generation includes Lakefield Junction, Pleasant Valley, and Cambridge Stations. Lakefield Junction is a six-unit dual fuel combustion turbine facility capable of burning natural gas or fuel oil. The station is currently rated at 497.0 MW in the summer and 550.0 MW in the winter. Pleasant Valley Station is a three-unit dual fuel combustion turbine facility capable of burning natural gas or fuel oil. The station is currently rated at 414.9 MW in the summer and 487.0 MW in the winter. Cambridge Station consists of a natural gas combustion turbine and a small fuel oil combustion turbine. The station is currently rated for 175.4 MW in the summer and 29.0 MW in the winter.

GRE also owns three other oil-fired combustion turbines, two of which (Rock Lake and Maple Lake) each have a summer rating of approximately 20.0 MW and a winter rating of approximately 27.0 MW. The third combustion turbine (St. Bonifacius) is currently rated for 56.0 MW in the summer and 70.0 MW in the winter.

4.2.2 Existing Renewable Resources

GRE provides renewable energy to its member cooperatives through its green energy pricing program and as part of its regular resource portfolio. Renewable resources included in GRE's portfolio include wind, refuse-derived fuel, anaerobic digesters and landfill gas.

GRE member cooperatives offer a green pricing option, Wellspring® Wind Energy, to their members. Cooperative members pay a premium to cover the incremental cost of the additional renewable energy. Wellspring® energy, purchased voluntarily by cooperative members, does not count toward fulfilling Minnesota's Renewable Energy Standard. GRE member cooperatives may offer Wellspring® in 100 kWh blocks, as a percentage of monthly usage or in predetermined contribution levels. GRE member cooperatives promote Wellspring® in regular

marketing efforts (newsletters and bill inserts); on their websites; and in special promotions (tours, member appreciation events).

GRE began acquiring wind resources in February 1999 by arranging for the development of three wind turbines with a combined nameplate capacity of 2 MW near Chandler, Minnesota. In December 2001, GRE added an additional 4 MW of wind energy at Chandler. In 2003, GRE began purchasing energy from a 6 MW wind facility in Dodge County, Minnesota and from a 6 MW wind facility in Jackson County, Minnesota.

In November 2005 GRE began to purchase the output of Trimont Wind I, LLC (Trimont), a 100 MW wind project located in Martin and Jackson Counties of Minnesota. In November 2007 GRE began to purchase the output of Prairie Star Wind, a 100 MW wind project located in Mower County in Minnesota.

GRE owns and operates Elk River Station, a waste-to-energy facility. The station utilizes refuse-derived fuel as its primary energy source, a renewable fuel as defined by Minnesota Statutes 216B.1691. Refuse-derived fuel is produced from municipal solid waste. Utilizing refused-derived fuel for energy recovery at Elk River Station reduces the amount of municipal waste that is landfilled by between 250,000 and 300,000 tons annually.

GRE has contracted to purchase the output of two anaerobic digester projects. Haubenschild Farms Inc., a large dairy farm with approximately 1,000 dairy cows, currently operates an anaerobic digester project with one 150 kW generator in the service territory of GRE member East Central Electric Cooperative. The digester project generates approximately 1,100,000 kWh per year. Northern Plains Dairy, a large dairy farm with approximately 3,000 cows, currently operates an anaerobic digester project with two 130 kW generators in the service territory of GRE member BENCO Electric Cooperative. The digester project generates approximately 2,000,000 kWh per year.

GRE has a contract with the Elk River Municipal Utility for the purchase of 3.2 MW of capacity and energy from landfill gas generators at the Elk River Landfill.

4.2.3 Committed Renewable Resources

GRE is purchasing the output of the 99 MW (nameplate) Elm Creek wind project. Elm Creek is under construction during 2008 and expected to reach commercial operation before the end of the year. It is located in close proximity to the Trimont project in Martin and Jackson counties.

4.2.4 Other Committed Resources

GRE is constructing a 175 MW combustion turbine at its Elk River campus to provide additional peaking capacity. It will be fueled primarily with natural gas, with ultra-low sulfur fuel oil as a back up. The project will be in service in early 2009.

GRE is participating in the Spiritwood Station, a combined heat and power project, with two industrial developers (an existing malting plant and a proposed ethanol plant). The project will be fueled with dried lignite from Coal Creek Station and will have an overall thermal efficiency of approximately 66%. While GRE intends for Spiritwood to ultimately be a capacity and energy resource of 99 MW, the project must sell its energy into the MISO market on a merchant basis until transmission arrangements for firm deliverability are fully in place. The project is partially baseload in nature (62 MW) and partially peaking in nature (37 MW). The project is expected to become available in two steps. Because of transmission limitations, only 50 MW of baseload capacity is projected to be available in the first quarter of 2010. Transmission for the remaining 49 MW (12 MW baseload and 37 MW peaking) may not become available before 2015.

GRE has contracted to purchase the output of a 5-7 MW pipeline compressor heat recovery system. It is located on the Northern Border natural gas pipeline near the city of Trimont in southwest Minnesota. It will be “fueled” by the high temperature exhaust of a combustion turbine in the natural gas pipeline compressor station. The plant is expected to become operational in the next two years. Since no additional fuel is consumed in producing the electricity there are no incremental emissions associated with it.

GRE is constructing an 18 MW emergency standby generator near Grand Marais, Minnesota to provide power during outages of the long radial transmission line serving that area. The plant will consist of nine 2 MW diesel generators and will be completed in July, 2008.

4.2.5 Existing Long-Term Purchase Resources

GRE has the following major long-term purchase resources:

- Life-of-the-plant contract with Dairyland Power Cooperative to purchase half the output (170 MW) of the Genoa 3 coal-fired plant, which is located in Genoa, Wisconsin.
- Manitoba Hydro capacity diversity exchange for 150 MW of capacity in the summer with 15 percent planning reserves. The contract expires on April 30, 2015.
- Northern States Power capacity diversity exchange for 50 MW of capacity in the winter. The contract expires on April 30, 2010.
- Minnesota Power 175 MW capacity and energy with 15 percent planning reserves. The contract expires on April 30, 2010.

Twelve of GRE's 28 members have been allocated hydropower from the Western Area Power Administration (WAPA) totaling 86.8 MW of summer capacity. GRE also directly receives an allocation of 3 MW of firm summer capacity. These are firm purchases that include 15 percent for planning reserves.

4.2.6 Major Sales

GRE has the following major long-term sale obligations:

- Willmar capacity contract for 30 MW. This contract expires on December 31, 2015.
- Manitoba Hydro capacity diversity exchange for 150 MW of capacity in the winter with 15 percent planning reserves. The contract expires on April 30, 2015.
- Northern States Power capacity diversity exchange for 50 MW of capacity in the summer. The contract expires on April 30, 2010.

4.2.7 Committed Purchases and Sales

GRE has no other long-term purchase or sale commitments at this time.

4.2.8 MISO Market and Short-term Transactions

MISO initiated a market for energy in April 2005. In the MISO Market, our generation facilities and contractual resources technically no longer directly serve our members' energy requirements. Instead, we and other MISO Market participants submit day-ahead or real-time bids and offers for the purchase or sale of energy at various locations in the MISO system. MISO then evaluates the bids and determines how to economically and reliably dispatch the generation facilities of all of the participants that submitted offers to sell energy on an hourly basis.

In practice, however, we meet a significant portion of our member requirements in the MISO Market by "self-providing" our member requirements with our base load generation facilities by offering these facilities into the day-ahead market in amounts that will serve our members and meet our obligations to third parties. We meet our remaining energy requirements by obtaining the least costly energy available from spot purchases of energy in the MISO Market, energy we offer into the MISO Market from our own facilities, or from bilateral contracts with entities outside of MISO⁴.

MISO settles hourly offers and bids based on locational marginal prices. Locational marginal prices are market-based prices corresponding to the specific time and location of the purchase or sale, taking into account transmission congestion and losses.

The clearing price paid by purchasers of energy and received by generators in any hour reflects the costs of the last incremental generation unit dispatched during that hour. Based on this process, generating facilities will normally not be dispatched unless they are operating economically. MISO reimburses generators if they dispatch uneconomically (i.e., when their

⁴ As noted in Section 8.1, we used a "self-serving" approach in our modeling work for this resource plan.

operating costs exceed the market clearing price) or are otherwise operated at MISO's discretion, such as for reliability reasons.

In addition to participating in the MISO market, GRE regularly enters into bilateral contracts for capacity and or energy for seasonal or shorter term periods to minimize our operating costs.

5 ENVIRONMENTAL CONSIDERATIONS

5.1 Operational Highlights of Existing Resources

5.1.1 Clean Air Act Title IV Requirements

Coal Creek Station and Stanton Station, as well as several of GRE's combustion turbine stations, have affected units under the federal acid rain regulations (Title IV of the Clean Air Act Amendments).

These regulations limit NO_x levels at Coal Creek Station to 0.40 lb/MMBtu at each unit and at Stanton Station to 0.46 lb/MMBtu for Unit 1 and 0.40 lb/MMBtu for Unit 10. The facilities have complied with their applicable limits through the installation of low NO_x burners and other combustion controls including over-fire air.

The acid rain program also places limits on emissions of SO₂ and creates a market for SO₂ emission allowances. Under this program, the U.S. Environmental Protection Agency allots a specified number of SO₂ allowances to each unit for each year. Utilities are free to:

- “under-control” and buy allowances,
- “over-control” and sell allowances, or
 - hold allowances for future use;
 - trade or transfer allowances in power sales or other transactions,
 - pool allowances with other utilities to mitigate risk, or
 - use allowance futures contracts and options to hedge against future price changes.

Upgrades have been made to the scrubbers on both units at Coal Creek Station and on Unit 10 at Stanton Station. Coal Creek Station's two units are allotted 44,497 allowances per year. Great River Energy also has installed a pollution control, energy recovery and emission reduction project at Coal Creek Station whereby the plant provides steam for an adjacent ethanol plant. More details on this project are provided in section 5.1.3.

Stanton Station's two units are allotted 8,781 allowances per year. In 2004, Stanton Station switched from lignite to Powder River Basin (PRB) coal. Switching to PRB provides several advantages. The plant handles and burns less coal because of PRB coal's higher heat content, resulting in lower emissions. In addition, ash generation and handling is reduced because PRB has an ash content that is 50% less than lignite. Stanton Station is currently designing a SO₂ scrubber for Unit 1, which will result in lower plant SO₂ emissions.

No additional modifications should be required for continued compliance with the SO₂ provisions of the acid rain program.

5.1.2 Fly Ash Sales

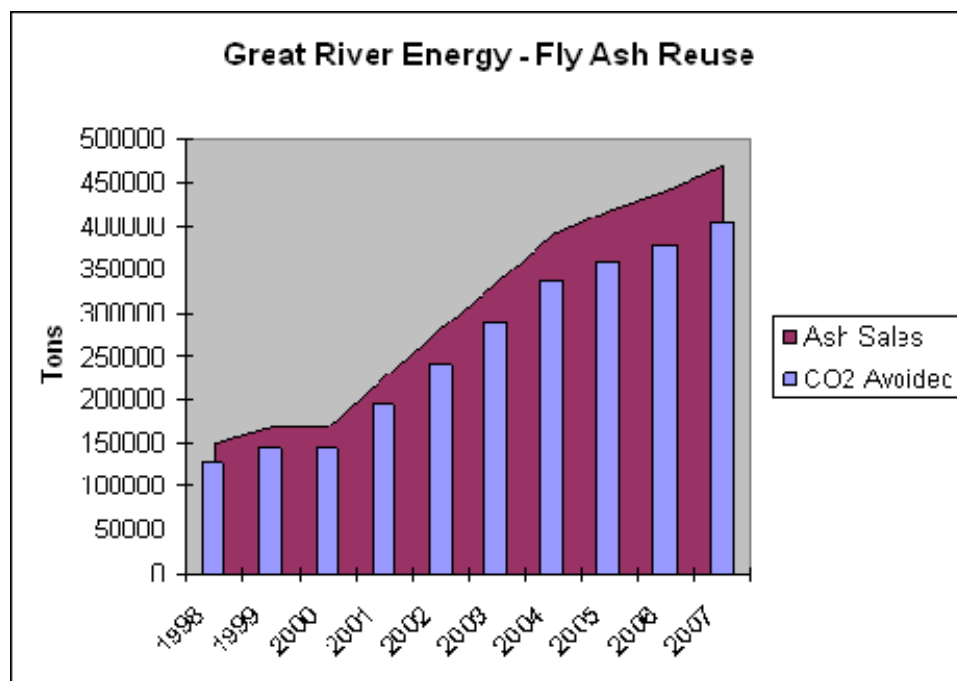
Since 2003, GRE has actively participated in the EPA's Coal Combustion Products Partnership (C2P2) to promote the benefits of coal combustion products – including fly ash.

As a by-product of coal combustion, GRE generates approximately 520,000 tons of fly ash per year at Coal Creek Station. Historically, fly ash was stored in landfills, but over the last ten years GRE has been very successful in finding alternative uses for it. It is primarily used as a partial replacement for cement, which makes the concrete stronger and more durable than concrete made with cement alone. It has also been used in other products. For example, fly ash was used in the backing of the carpet in GRE's new headquarters building.

Re-using the ash avoids cement production, reducing CO₂ emissions in the cement production process. For each ton of fly ash that is used as a cement replacement, greenhouse gas emissions are estimated to be reduced by just over 0.8 tons. Since 1998, nearly 2.5 million cumulative tons of CO₂ have been avoided through GRE's ash re-use.

By re-using the ash, GRE also avoids storing the ash in landfills, resulting in cost savings of over \$4 per ton. Since 1998, over \$10 million in cumulative landfilling costs have been avoided through re-use.

Stanton Station fly ash has been used to replace cement and scoria fines as a product to absorb the oil/water sludge created during oil well drilling and for soil stabilization. Today nearly all the Stanton fly ash is used in the oil field industry.

Figure 5-1 Coal Creek-Fly Ash Reuse

5.1.3 Cogeneration for an Ethanol Plant

GRE completed integration of Blue Flint Ethanol with Coal Creek Station, which provides steam for their distiller's grain drying and other system thermal requirements. In addition to the benefit of using low pressure steam that would normally be unused, the project will result in much lower emissions than a stand-alone ethanol project.

The primary benefit of locating the ethanol plant adjacent to Coal Creek Station is to allow for beneficial use of low temperature/quality energy from Coal Creek Station by the ethanol facility. Approximately 60 percent of the process steam for the ethanol facility will come from recovery and use of low pressure steam at Coal Creek Station. This steam is not usable in Coal Creek Station's steam cycle, and it would normally be rejected to the cooling towers as waste heat. The remaining 40 percent of the ethanol plant's process steam needs are for higher pressure steam, which also comes from Coal Creek Station.

As part of the cogeneration project, several improvements were completed at Coal Creek Station that will result in large emission reductions. With respect to SO₂ emissions, these include installation of liquid distribution rings, upgrades to the mist eliminator wash system, and the addition of air heater seals. These improvements are expected to reduce net SO₂ emissions from the station by approximately 900 tons per year. With respect to NO_x emissions, the improvements include installation of new manual tilt drives on the Unit 1 separated over-fire air compartments. The new tilt drives in conjunction with the reduced air heater leaks are expected to reduce NO_x emissions by approximately 600 tons per year.

5.1.4 Coal Drying Project

In January 2003, the U.S. Department of Energy selected Great River Energy's Coal Creek Station to participate in a clean coal technology project. Through the project, Coal Creek Station conducted a large-scale coal-drying study to determine if it is feasible to dry large quantities of lignite for use at the plant. Lignite has a high moisture and ash content. By reducing the moisture and ash content, less coal is required to generate the same amount of electricity. This also results in fewer emissions. Through the project, the moisture content of lignite will be reduced from 38 percent to less than 30 percent. This will improve the quality of lignite - making it closer to the quality of PRB sub-bituminous coal from Montana and Wyoming. As a result, efficiencies will increase by 2.8 to 5 percent. Sulfur dioxide emissions are expected to decrease by 25 percent. Mercury, carbon dioxide, nitrogen oxides and particulate emissions are also all expected to decrease due to the reduction of the flue gas volume and dryer density separation.

The dryer technology is being applied to one of the two units. The dryer is under construction and expected to be in operation by 4th quarter 2009. GRE is pursuing marketing the dryer technology for use in other power plants.

5.2 Future Environmental Regulations

GRE has provided a comprehensive overview of potential future environmental regulations in its prior resource plan filings. The Commission has ordered GRE to continue to include updates on environmental issues and contingency plans for compliance with expected future regulations. The policies have not changed significantly since our last filing.

5.2.1 Regional Haze

The U.S. Environmental Protection Agency (EPA) published final regional haze regulations in 1999. The goal of these regulations is to improve visibility in Class 1 areas, such as national parks and wilderness areas, to reach "natural conditions" by 2064. The rule requires certain power plants to install Best Available Retrofit Technology (BART) to control SO₂, NO_x and Particulate Matter (PM). Since 2005, Great River Energy has been working closely with the North Dakota Department of Health (NDDH) and has provided detailed BART analyses for each affected unit that identifies feasible control options for each pollutant, cost estimates for the respective controls, expected emission rates and associated visibility improvements for each combination of controls. NDDH is expected to issue their final BART determination soon. These emission controls must be installed and operational no later than 5 years after EPA approves the North Dakota BART State Implementation Plan (SIP), which may be as soon as 2013. Coal Creek and Stanton stations have been working diligently on their BART control strategies and do not anticipate any difficulty meeting the regulatory timelines.

In 2018, NDDH will start the second round of regional haze reductions. Cost effective controls and associated visibility improvements will again be determined for all emission sources in the state with an effective date of 2023 for any applicable control requirements.

5.2.2 National Ambient Air Quality Standards

The U.S. Environmental Protection Agency (EPA) periodically reviews the National Ambient Air Quality Standards (NAAQS) to determine the protectiveness of the existing standard. In 2008, the eight-hour ozone standard was changed from 0.08 parts per million to 0.075 parts per million. The one-hour ozone standard was revoked except in limited areas of the country. A new fine particulate matter (PM_{2.5}) standard was created in 1997 at a maximum annual average of 15 micrograms per cubic meter and the maximum 24-hour average was revised in 2006 to be 35 micrograms per cubic meter.

Minnesota and North Dakota are in attainment with the revised ozone and PM_{2.5} NAAQS. As such, the NAAQS change is not expected to directly impact GRE's operating plants. Indirectly, the Clean Air Interstate Rule (CAIR), developed to assist non-attainment areas come into compliance with the limits, will affect GRE's Minnesota facilities. CAIR is discussed further in Section 5.2.4.

5.2.3 Mercury

Since the late 1990s, Great River Energy has been an industry leader in researching mercury reduction technologies at our plants. We continue to work with partners such as the Electric Power Research Institute (EPRI), U.S. Department of Energy (DOE), and North Dakota's Energy & Environmental Research Center (EERC) to identify and test novel mercury reduction technologies.

In 2005, the EPA published its Clean Air Mercury Rule (CAMR). Coal Creek and Stanton stations were covered by this rule and had made plans to install controls and monitor their emissions in compliance with this cap and trade program. The CAMR rule was then vacated by the U.S. Court of Appeals for the DC Circuit on February 8, 2008. The EPA sought review by the full District Court, which request was denied. The time for appeal has not yet expired.

If the DC circuit court ruling holds, EPA will be required to develop Maximum Achievable Control Technology (MACT) standards under Section 112 of the Clean Air Act, which could take several years. EPA has indicated that the likely rule would require 90 percent removal, the same standard contained in the Minnesota Mercury Emission Reduction Act of 2006 (MMERA). The MMERA requires a public utility that owns a dry-scrubbed or wet-scrubbed coal-fired electric generation unit with capacities greater than 100 megawatts (MW) to propose to employ the available technology for mercury removal that is most likely to result in the removal of 90 percent of the mercury emitted from the unit. The EPA is likely on a 12-month schedule to propose a Utility MACT standard, which would result in final rules in 2010. Since Great River Energy has conducted and continues to conduct significant mercury reduction research at our plants, we are uniquely positioned to respond to either a CAMR or MACT regulatory program once finalized.

5.2.4 Clean Air Interstate Rule

The Clean Air Interstate Rule (CAIR), a two-emission rule, was signed March 10, 2005 by the EPA Administrator. CAIR requires reductions in emissions from states that will contribute

significantly to non-attainment of, or interfere with the maintenance of, the PM_{2.5} and/or the 8-hour ozone National Ambient Air Quality Standards (NAAQS). Minnesota has been identified as a significant contributor in the PM_{2.5} NAAQS and will be required to reduce SO₂ and NO_x emissions. Therefore, GRE's Minnesota facilities will be required to comply with the CAIR provisions. CAIR emission reductions will be implemented in two phases: Phase I will begin in 2009 and 2010 for NO_x and SO₂, respectively, and Phase II will begin in 2015.

CAIR SO₂ emission reductions are based on Title IV Phase II allowance levels. Required SO₂ emission reductions are 50 percent in 2010 and 65 percent in 2015. CAIR NO_x emission reductions are based on emissions from facilities in existence at the time of rule promulgation. A new allowance system is being implemented for NO_x emissions. Required NO_x emission reductions are approximately 56 percent in 2009 (from units in existence from 1999 - 2002) and 64 percent in 2015.

The state of Minnesota currently has no plans to submit a State Implementation Plan (SIP) for CAIR. CAIR administration in Minnesota is proceeding under the U.S. Environmental Protection Agency's Federal Implementation Plan (FIP) published in 2006 with amendments in 2007.

5.2.5 Greenhouse Gas Emissions

There is currently no state or federal regulation of CO₂ emissions. The United States has not signed the Kyoto Protocol and it is not likely to sign any international agreement under the current administration. Nevertheless, GRE continues to evaluate its greenhouse gas emissions and assess opportunities for carbon reduction.

GRE actively participated in Minnesota's Climate Change Advisory Group process to develop a state action plan. We are involved with the Midwest Governors Association's Energy Initiatives and have a seat on the Energy Efficiency Advisory Group. GRE is a partner in the U.S. Environmental Protection Agency's SF₆ Emission Reduction Partnership for Electric Power Systems program whereby we establish and report progress towards annual SF₆ (sulfur hexafluoride) reduction goals. GRE continues to be a funding member of the Energy & Environmental Research Center's Plains CO₂ Reduction partnership (PCO₂R) which conducts research into CO₂ sequestration. We have an established cross-functional carbon team that is evaluating opportunities for carbon reduction and offsets. GRE has been tracking and voluntarily reporting its greenhouse gas emissions since 1995. GRE is a Founding Reporter of The Climate Registry. In assessing generating technologies to meet its customers' needs, GRE includes externality costs for CO₂ emissions.

5.2.6 Impaired Waters and Total Maximum Daily Loads

Every two years the U.S. Environmental Protection Agency (EPA), under the Clean Water Act, requires states to publish and submit an updated list of waters that do not meet designated uses due to pollutant impacts. The impaired waters list, 303(d) list, includes lakes, streams and rivers with impairments for use as drinking water, fishable waters, swimming, industrial use and/or irrigation.

Once the water body is listed, the state must begin the process of addressing the impairment. The first stage of this process is development of a total maximum daily load (TMDL). A TMDL is the total maximum daily pollutant load a water body can receive from all sources while maintaining applicable water quality standards and supporting the water body's designated uses.

The development of a TMDL is designed to assess the load on a water body from point sources, non-point sources, and natural background conditions. Once these loads are quantified, each source can be assigned a given amount of pollutant load expected to ensure the receiving water body will meet water quality standards and designated uses.

At this time states are generally in the water body assessment phase, but TMDLs have either been developed or are in development for an increasing number of water bodies. As this process proceeds, TMDLs will likely be developed for water bodies to which GRE either has or is seeking permitted discharges. This could change discharge limits, result in limits for additional analytical parameters or even possibly preclude permitting of a new or expanded discharge to a given water body. The most likely affected parameters include mercury, phosphorous, total suspended solids, and temperature.

In many instances the impairments mentioned above have significant contributions from non-point and natural background sources. Due to the difficulty in controlling the loads from these sources, significant reduction goals may be allocated to point sources such as GRE's permitted discharges. Retrofitting existing facilities and implementing new pollutant reduction technologies will likely require significant capital expenditure to achieve relatively small reductions for a given pollutant. Based on this it appears pollutant trading and restoration projects will play a significant role in the TMDL process. GRE will continue to monitor TMDL development and assess potential impacts to our facilities.

5.2.7 Aquatic Life Protection at Cooling Water Intake Structures

Section 316(b) of the Clean Water Act requires that the location, design, construction, and capacity of a cooling water intake structure (CWIS) reflect the best available technology (BAT) for minimizing environmental impact including threat to aquatic life. As part of a settlement agreement EPA began development of new regulations to address impacts to aquatic life at CWISs. The new regulations consist of three phases. Phase I (released December 18, 2001) applies to new facilities with a CWIS. Phase II became final July 9, 2004 and applies to existing utility power plants that have an NPDES permit and a CWIS with a design capacity of greater than 50 million gallons per day (mgd). Phase III was proposed November 24, 2004 and applies to non-utility CWISs greater than 50 mgd. The Phase II rule was remanded back to EPA by the 2nd Circuit Court in early 2008. Currently, EPA is rewriting the rule to address the Court findings.

Phase I of the rule applies to any new facilities with an NPDES permit and a CWIS design of greater than 2 mgd. The rule provides a two-track decision making process of either installing highly protective intake technologies or conducting a site-specific analysis of the proposed CWIS's impacts to aquatic life. The study must demonstrate the proposed CWIS will be

adequately protective of aquatic life. Any new projects planning to utilize surface water for cooling purposes will have to address Phase I of the rule.

Phase II of the rule is for existing utility CWISs based on the parameters mentioned above. The previous Phase II rule applied performance standards based on the size of the intake, the amount of water it withdraws and the source water body type. With the Phase II portion currently being rewritten by EPA, specific performance standards and what constitutes “best available technology” are unknown at this time.

Any new requirements will affect Elk River Station and Stanton Station. Currently both stations have completed initial strategy analyses for compliance with the new rule and are conducting baseline and limited planning exercises based on available information.

5.3 Renewable Energy Objectives and Standard

5.3.1 Compliance Status

GRE has added renewable resources well ahead of the renewable energy objectives of Minn. Stat. §216B.1691. Figure 5-1 shows GRE’s renewable energy surpluses in MWh over the past 6 years.⁵

Figure 5-2 Historical Renewable Compliance

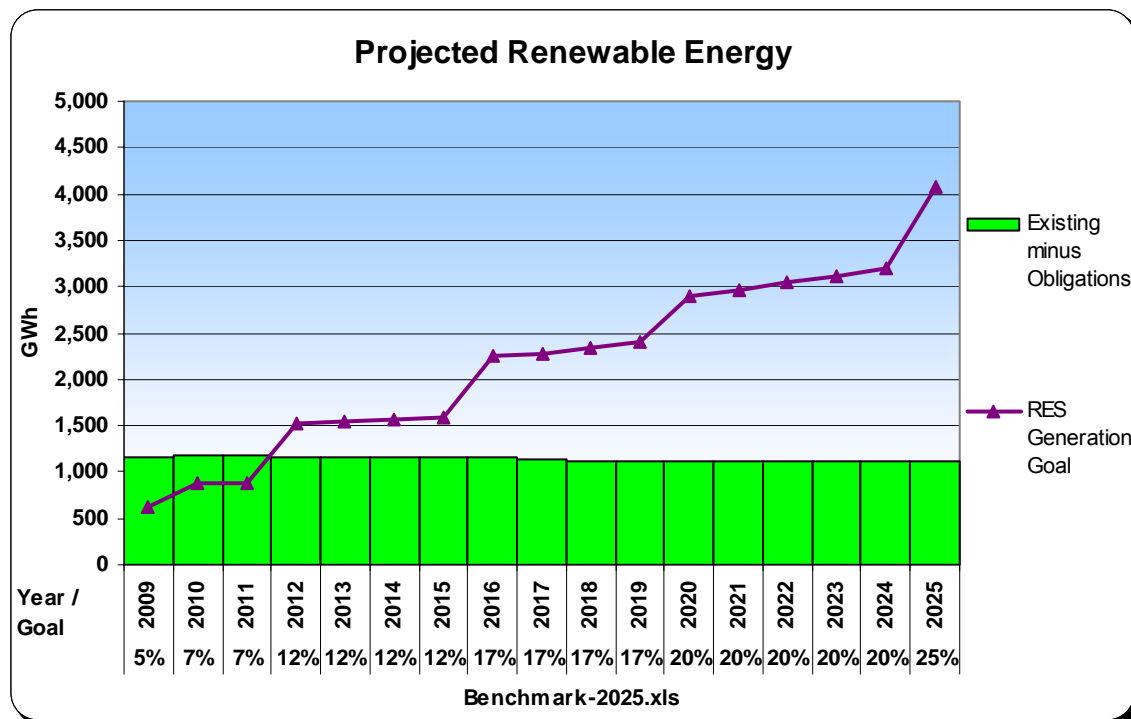
Year MWh	Total Renewable Generation	Renewable Generation Available for MN REO	Renewable Generation Required for MN REO	Surplus (Deficit)
2002	197,459	178,307	108,124	70,183
2003	225,397	200,842	112,127	88,715
2004	250,454	227,772	115,019	112,752
2005	294,246	270,103	122,352	147,751
2006	553,181	306,988	125,611	181,377
2007	594,994	435,388	129,927	305,461

As shown in Figure 5-3, with the existing and committed renewable resources described in Section 4.2.2 and 4.2.3, GRE has sufficient renewable resources under contract to meet the renewable energy objectives of Minn. Stat. §216B.1691 through 2011 and is well on the way toward meeting the first tier (12% during 2012-1015) of the eligible energy technology standard

⁵ The differences between “Total Renewable Generation” and “Renewable Generation Available” are due to Wellspring Wind Energy (green pricing) sales, renewable energy credit sales, and renewable energy allocated to Wisconsin. “Renewable Energy Required” is for the 1% of retail sales renewable energy objective applied to GRE member sales adjusted for delivery losses.

(renewable energy standard) of that statute. Significantly more renewable resources will be needed to meet the subsequent tiers. Investigating the resource mix implications of adding those resources was a significant part of the modeling aspects of this resource plan.

Figure 5-3 Projected Renewable Compliance with Existing and Committed Resources



GRE is registered with the Midwest Renewable Energy Tracking System (M-RETS) established pursuant to Docket E-999/CI-04-1616.

5.3.2 Compliance Efforts

Most of GRE's renewable energy is purchased under long-term contracts with project owners. We identified most of these contract opportunities through requests for proposals (RFPs). We issued our most recent RFP in May, 2007 and received over 60 proposals, mostly from wind developers, totaling approximately 3500 MW. We expect to continue issuing RFPs and considering unsolicited proposals as opportunities arise.

5.3.3 Obstacles Encountered or Anticipated

The obstacles that we have encountered are not unique to GRE, but are significant:

- Transmission.
 - Interconnection queue. The MISO generator interconnection queue operates on a first in, first out basis and is overrun with requests, particularly in areas with high wind development potentials. The length of the queue has fed upon itself as even highly speculative projects must queue up early to preserve any chance of getting studied and connected. This has resulted in severe uncertainties about when proposed interconnections will be studied, let alone actually get built.
 - Transmission capacity. Because of an overall lack of transmission capacity, many projects that do get interconnected are limited to using transmission on an as-available basis⁶. As a result, they or the utility purchasing energy from them are exposed to unhedged congestion costs and a greater risk of curtailments. The magnitude of these risks depends in large measure on how quickly such generating resources are added relative to the rate at which transmission capacity is expanded. Having adequate transmission capacity is also important in assuring that the grid can reliably and economically accommodate the intermittency of wind energy. This will grow in importance as the proportion of wind energy in the region increases. Some of the issues inhibiting transmission development are described briefly in Section 9.4.
 - MISO seams. Projects served by transmission systems that are not part of the MISO network are subject to pancaked transmission charges by the non-MISO transmission providers. Those charges put such projects at a severe cost disadvantage when serving loads within MISO, including GRE's. For GRE, this inhibits utilizing wind resources in many parts of the Dakotas.
- Equipment Supplies and Costs. Project costs have increased significantly in recent years due to a combination of strong global demand for wind energy and tight supplies of equipment (especially wind turbines), increased costs of commodities and components, the weakness of the dollar, and higher delivery and construction costs.
- Production Tax Credit (PTC) uncertainties. The federal PTC is a significant factor in the economics of wind projects, far too large to ignore. Yet the PTC has a history of being renewed erratically and for relatively short periods of time, making project timing critical and bringing a certain boom-and-bust characteristic to wind energy development in the U.S.
- Long-term Reliability. Most wind projects in this region are in early stages of their economic lives and are using equipment of recent design. The base of experience with keeping wind projects operating over the long term is relatively thin. Some projects

⁶ Many wind projects have only Energy Resource Interconnection Service rather than Network Resource Interconnection Service or an accompanying transmission service reservation, either of which would reserve transmission capacity for the wind project **but often requires more costly network upgrades**. Reserved transmission capacity is necessary to acquire congestion hedges (in the form of Financial Transmission Rights or Auction Revenue Rights) and a higher priority with respect to curtailments.

have experienced serious equipment failures⁷ and unexpected maintenance costs and downtimes.

- Contract Expirations. While GRE's power purchase agreements are long-term, they will eventually expire and will need to be renegotiated or replaced in the post-2025 timeframe. Project developers are tending to disfavor long-term contracts, which conflicts with our desire for stable, long-term resources.

5.3.4 Potential Solutions to Obstacles

- Transmission.
 - Interconnection queue. MISO is proposing to reform the generator interconnection queue by favoring projects that produce evidence that they are likely to get built. MISO filed this proposal with the FERC June 26, 2008. If successful, this approach will bring far more rationality to the generator interconnection process and will reduce a major uncertainty in wind resource development and acquisition efforts.
 - Transmission capacity. Efforts to plan and build additional transmission capacity are described in Section 10, including studies and discussions among the many stakeholders who are interested in furthering the development of renewable resources.
 - MISO seams. MISO has proposed to offer certain market services to non-MISO utilities to address some of the seams issues between them and MISO⁸. This proposal will not, however, eliminate pancaked transmission charges for generating projects that interconnect with non-MISO transmission systems. Such projects will continue to be at a competitive disadvantage in serving GRE and other MISO members.
 - Storage. Some of the transmission capacity and network integration issues associated with wind and other nondispatchable resources could be addressed by deploying storage technologies such as batteries, pumped hydro, or compressed air. In addition to investigating these technologies at the utility scale, GRE and its members are exploring use of customer-side technologies such as storage space and water heating and plug-in hybrid vehicles as potential ways to make better use of nondispatchable renewables.
- Equipment Supplies and Costs. The current market favors developers and utilities who have secured supplies of turbines and other critical equipment. However, as the wind energy business matures, equipment supply shortages should diminish and equipment prices should become more cost-driven. How and when this will happen is a matter of much interest and debate industry-wide.
- Long-term Reliability. Increasing experience with the installed fleet of wind turbines will, over time, reduce uncertainties about maintenance requirements and costs. GRE is a member of organizations such as the American Wind Energy Association and the Utility

⁷ A wind farm serving GRE suffered separate catastrophic fires in two wind turbines in 2008, destroying the turbines in both instances.

⁸ This "Module F" proposal is currently before the FERC in docket ER08-637.

Wind Interest Group that are working to make wind an economical and reliable resource over the long haul.

- Contract Expirations. GRE continues to favor proposals with longer terms. We are investigating opportunities to take ownership positions in future projects for a portion of our portfolio.
- Non-Wind Renewables. In addition to wind, GRE continues to pursue other eligible technologies such as biomass and anaerobic digesters, both through our RFPs and through unsolicited proposals. To the extent that the resources are dispatchable, we credit them with the value of the capacity that they provide. In addition, GRE's member cooperatives have numerous small wind, solar, and methane projects connected to their distribution systems.

5.3.5 Community-Based Energy Development (C-BED)

In GRE's most recent renewable RFP, we expressly encouraged proposals from C-BED projects. About half of the 3500 MW of proposals that we received were from self-declared C-BED projects. Unfortunately, all but a handful of those projects were too far back in the MISO interconnection queue to be ripe for consideration at this time. GRE short-listed several C-BED projects for further evaluation and power purchase contract negotiations, but all have encountered delays with their interconnections or other problems. The problems with these projects are not necessarily a result of their C-BED status – they are for the most part encountering the same obstacles noted in Section 5.3.3 that all projects are facing. We are taking a patient approach with these projects and provide information and guidance where we reasonably can. But for now, we have no C-BED projects on-line or under contract.

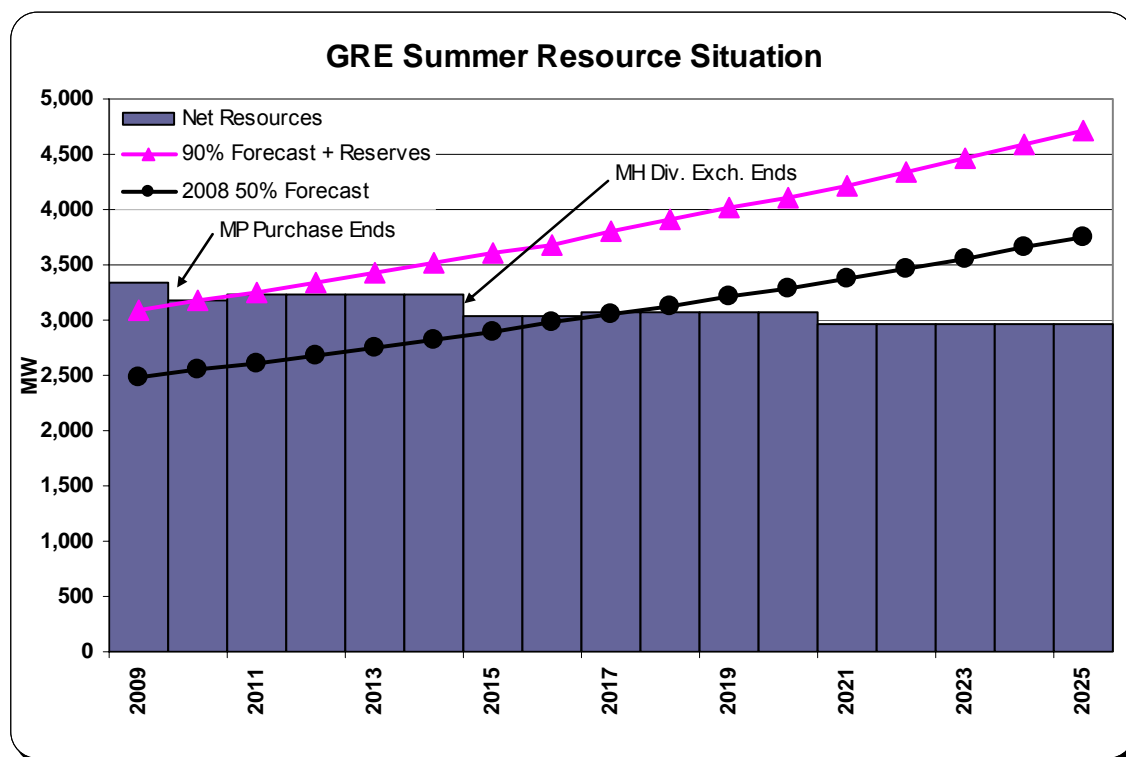
6 RESOURCE REQUIREMENTS

This section describes GRE's net resource requirements after considering the forecasted demand and existing resources. In response to efforts to meet the Minnesota 1.5% Energy Conservation Policy Goal and to ascertain the impact of meeting it compared to continuing our historical trend of conservation, we have evaluated GRE's summer resource situation under both the 2008 Exploratory Risk Analysis Econometric Model (ERAEM) forecast with conservation at historic trends and this forecast adjusted for additional conservation.

Only annual energy savings as a result of specific conservation programs implemented by GRE are counted toward CIP goals. However, programs implemented will have an ongoing effect of reducing energy needs. Therefore, the effects of annual conservation programs have been assumed to continue for an average of ten years. Thus additional conservation efforts have a cumulative effect on the load forecast. A value of 1 kW for every 5,267 kWh of conserved energy was used in the analysis of the effects of energy conservation on peak demand⁹. Specific results of the conservation adjustment are documented in Appendix B.

6.1 GRE's Summer Resource Situation

Figure 6-1 GRE Summer Resource Situation based on the 2008 ERAEM Forecast



⁹ This value was used in our analysis as recommended by the MN Department of Commerce in their comments dated December 21, 2007 in the Elk River Peaking Station Certificate of Need proceeding (Docket No. ET2/CN-07-678).

Figure 6-2 GRE Summer Resource Situation based on 2008 ERAEM Forecast Adjusted for the Effects of Additional Conservation

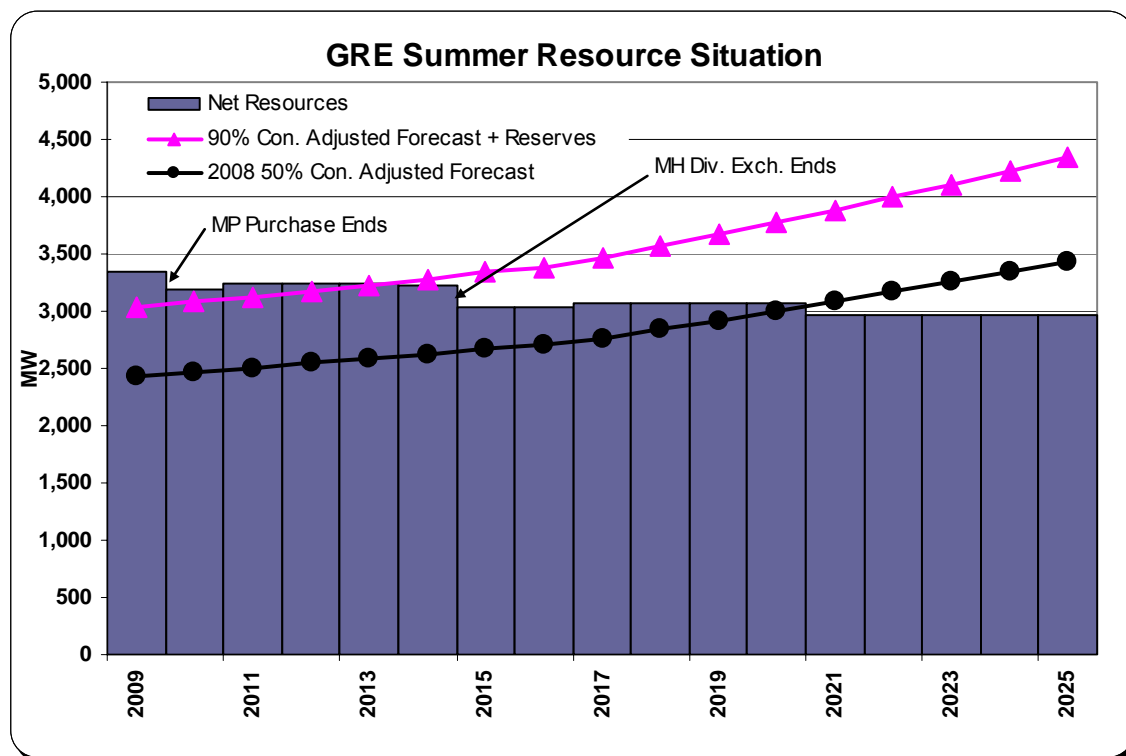


Figure 6-3 GRE Projected Surplus/Deficit Based on the 2008 ERAEM Forecast and the Forecast Adjusted for Additional Conservation

GRE Projected Surplus/Deficit on 2008 ERAEM Forecast			GRE Projected Surplus/Deficit on 2008 ERAEM Forecast Adjusted for the Effects of Conservation		
Year	PROJECTED SURPLUS/DEFICIT (MW)	EFFECTIVE RESERVES	Year	PROJECTED SURPLUS/DEFICIT (MW)	EFFECTIVE RESERVES
2009	339.7	30.5%	2009	396.5	33.5%
2010	138.7	20.8%	2010	230.0	24.9%
2011	126.5	20.1%	2011	252.5	25.7%
2012	57.7	17.3%	2012	218.4	24.2%
2013	-12.9	14.5%	2013	182.5	22.6%
2014	-91.4	11.5%	2014	139.3	20.7%
2015	-354.6	2.6%	2015	-88.6	11.6%
2016	-415.7	0.7%	2016	-114.5	10.7%
2017	-479.3	-1.0%	2017	-141.6	9.8%
2018	-563.7	-3.4%	2018	-225.8	6.9%
2019	-657.1	-5.9%	2019	-319.1	3.8%
2020	-727.9	-7.7%	2020	-387.8	1.7%
2021	-922.8	-12.3%	2021	-580.8	-3.9%
2022	-1,016.3	-14.4%	2022	-672.5	-6.3%
2023	-1,109.4	-16.3%	2023	-760.5	-8.5%
2024	-1,214.1	-18.4%	2024	-860.8	-10.9%
2025	-1,311.8	-20.3%	2025	-954.1	-13.0%

These deficit numbers are derived by subtracting the 90% confidence of each demand forecast from available resources. This is sufficient for long-term planning. However, GRE bases its short-term capacity planning on recent actual load levels, expected weather and economic trends, market conditions, and other contemporary information.

6.2 Contingencies that May Impact Supply and Demand

Policy decisions concerning carbon reductions have the potential to significantly impact both supply and demand. GRE currently relies on coal for a large percentage of the energy that we supply. These resources could be significantly impacted by carbon management policy choices that result in high CO₂ costs. Carbon management policies that result in higher electricity prices will likely reduce demand.

Planning capacity reserve margin levels may change with the continuing evolution of MISO and regional wholesale markets. GRE is currently a member of the MAPP Generation Reserve Sharing Pool, which requires a 15% reserve margin based on actual (after-the-fact) peak loads. However, as part of GRE's transition into MISO, we are considering joining the Midwest Planning Reserve Sharing Group (Midwest PRSG), a larger group which is more closely aligned with MISO. Within the Midwest PRSG, planning reserves are based on a percentage (initially 14.2% for GRE) of forecast expected (50% probability) demand. The net effect of this change would be to reduce GRE's planning reserve requirements by approximately 150-200 MW. The Midwest PRSG is expected to be a transitional arrangement, to be supplanted by MISO's Reserve Adequacy Requirement (Module E), which is currently under review by the FERC (Docket ER08-394-000).

The recent increase in the prices of fuels used for residential space heating has provided a direct incentive for customers to choose electricity for space heating, a switch that may occur rapidly. Although GRE and the region have surplus of winter capacity, space heating loads tend to have relatively high load factors, which may drive the need to adjust the resource mix even if no additional capacity is needed in the short run.

6.3 Changes in GRE Members' Purchases from GRE

As described in Section 1.1, eight of GRE's members have elected to fix the amount of capacity and associated energy that they obtain from GRE and to serve their growth from other suppliers. The remaining 20 members have elected to remain all-requirements customers of GRE under long-term contracts. In this resource plan, we have adopted the approach of including in our forecasts all of the demand and energy requirements of all of our members, including the eight "fixing" members. We have accounted for the future growth of the "fixing" members by identifying a category of nonspecific resources to be supplied by others.

7 RESOURCE OPTIONS

This section considers a comprehensive set of demand and supply-side resource options that could be implemented to meet GRE's resource requirements.

7.1 Demand Side Options

GRE's preferred plan assumes that we will meet the 1.5% Energy Conservation Policy Goal of Minn. Stat. §216B.2401 (2007). How GRE will strive to meet that goal is described in GRE's 2008 Conservation Improvement Plan filed June, 2 2008 (Docket No. 08-254) and included here by reference.

7.1.1 DSM as a Resource

GRE and our members have put significant efforts into using Demand Side Management (DSM), which includes energy efficiency, conservation and load management to reduce its needs for supply-side resources.

For load management, GRE's member cooperatives have installed over 230,000 directly-controlled loads, which give GRE the capability of reducing its summer peaks by approximately 200 MW or nearly seven percent of its peak.

The commitment of GRE and our members to conservation and energy efficiency continues to grow, evidenced by its increasing energy efficiency program rebates, loan programs and increased staffing. The additional program dollars and staffing will focus on furthering GRE and the member cooperatives conservation and energy efficiency efforts with the intent of meeting the conservation policy goal established in the 2007 legislative session.

Program participation and market penetration in the various DSM programs is encouraged by evaluating and, when necessary, changing or adding programs to ensure a better fit with market realities and GRE requirements. Two recent examples of program additions include: GRE's LEED loan program and the Energy Efficient Equipment (3E Loan Program). GRE's member cooperatives may also provide feedback that particular programs are not cost effective, or marketing efforts need to be redirected for better customer saturation.

GRE continues to promote its very successful cycled air conditioning program. Of GRE's nearly 630,000 end-use consumers, approximately 55% have central air conditioning in their homes. Today, GRE cycles over 130,000 of these central air conditioners on hot summer days. This represents a nearly unprecedented 33% customer participation rate in the cycled air conditioning program. Air conditioner use is a primary driver behind GRE's summer peak. Thus the cycled air conditioning program is one of GRE's best load management resources to reduce its annual peak.

7.1.2 Future DSM Program Development

In developing its DSM program portfolio, GRE examines the overall potential of demand-side resources among its end-use consumers. To do this, we analyze the following:

Technical Potential: The study starts with the entire universe of programs that can reduce demand for capacity and energy.

Economic Potential: This step narrows the scope to the programs that pass certain cost-benefit tests.

Achievable Potential: This final step considers more intangible factors such as consumer preference and saturation of programs.

In 2006, we contracted with an advanced analytics consulting firm, Quantec, LLC, to conduct an energy conservation potential study. The goal of the study was to identify DSM resource types that focused primarily on energy efficiency and to develop bundles/blocks of DSM resources that could then be included in our capacity expansion modeling. Some of the key results of the study included:

- Quantec did not identify any economic programs that were missing from GRE's DSM portfolio.
- Quantec helped to demonstrate to GRE the practical limits to achievable energy conservation
- Quantec identified some bundles of existing programs such as weatherization programs and appliance rebates which could be modified (e.g. higher rebates or overall budgets) that would result in increased energy savings.

We used the results from the Quantec study to help analyze its energy efficiency programs. Changes implemented included increasing our budget for conservation program rebates.

Despite our strong commitment to demand side programs, we acknowledge that there are practical challenges in developing them and unique risks in relying upon them. The results achieved through demand side programs depend upon consumer actions that are inherently more difficult to predict, monitor, measure, and control than supply side resources. For example, new programs take time to develop momentum and old programs can sometimes maintain momentum beyond their usefulness or lose momentum as consumer preferences change. Costs per kW or KWh reduced are often uncertain and depend on factors such as program costs, saturation rates, and estimates of what consumers would have done absent the programs. Some programs involve subsidies that require compromises among perceived winners and losers to effect. Nevertheless, we firmly believe that demand side programs are more important than ever in today's environment. We are committed to seeking ways to help our members make the most of the energy they use.

7.2 Supply Side Options

7.2.1 Generic Resource Options

The following generic supply side resource options were evaluated in the capacity expansion modeling described in Section 8. These resources are considered as proxies that represent classes of resource types.

Further characterizations of these resources are included in Appendix E (Trade Secret).

1. **Wind**, in 100 MW (nameplate) blocks. Wind resources were assigned a capacity value of 12% of nameplate based on GRE's experiences with its existing wind projects.
2. **1x0 Simple Cycle Gas Turbine**: a current state of the art frame-type combustion turbine.
3. **2x0 Simple Cycle Gas Turbine**: same as #2 except having two combustion turbines on one site, which provides some scale economies.
4. **1x0 Advanced Simple Cycle Gas Turbine**: An advanced combustion turbine such as the General Electric LMS 100. Such machines are capable of more flexible operation than frame-type combustion turbines and operate at higher efficiencies.
5. **2x0 Advanced Simple Cycle Gas Turbine**: same as #4 except having two units on one site.
6. **4x0 Advanced Simple Cycle Gas Turbine**: same as #4 except having four units on one site.
7. **1x1 Combined Cycle Gas Turbine**: a current state-of-the-art combustion turbine with the exhaust heat recovered in a heat recovery steam generator (HRSG) to power a steam turbine-generator.
8. **2x1 Combined Cycle Gas Turbine**: same as #7 except having two combustion turbines, both exhausting heat to a HRSG, which powers a single steam turbine-generator.
9. **1x1 Hybrid Peaker**: similar to a combined cycle gas turbine, but having a HRSG that is capable of "running dry", which allows the combustion turbine to be run independently of the HRSG and the steam turbine-generator. This is a very flexible resource since it retains all of the operating flexibility of the combustion turbine (including rapid start up) while providing efficiency similar to a conventional combined cycle plant when all of the elements are placed in operation.
10. **Ultra Supercritical PC (without CO₂ capture)**: Pulverized coal (PC) boilers are characterized by the steam conditions (temperature and pressure) that they are capable of providing. Most existing PC boilers are designed for sub-critical steam conditions, such as 1,000F and 2,400 psig. Ultra supercritical designs use more advanced materials that allow greater temperatures and pressures, typically 1,100F and 3,600 psig, resulting in greater efficiency. This technology was assumed to become available for service in 2014.

11. **Ultra Supercritical PC (with CO₂ capture):** same as #10 except with the addition of post-combustion capture of CO₂. The CO₂ capture capability results in a higher heat rate (lower efficiency) and a higher capital cost. This technology was assumed to become available for service in 2015.
12. **IGCC (without CO₂ capture):** a current state-of-the-art Integrated Gasification Combined Cycle power plant without CO₂ capture. This technology was assumed to become available for service in 2014.
13. **IGCC (with CO₂ capture):** same as #12 except with added CO₂ capture capabilities. This technology was assumed to become available for service in 2015.
14. **Advanced Ultra Supercritical PC with CO₂ Capture:** like #10, but an advanced design taking advantage of research expected to increase steam conditions to 1,400°F and 5,000 psig and CO₂ capture using more efficient reagents, resulting in both reduced capital costs and improved efficiency. This technology was assumed to become available for service in 2020.
15. **Advanced IGCC with CO₂ Capture:** like #13, but an advanced design taking advantage of research expected to reduce auxiliary power consumption, increase component efficiency, and use high hydrogen content synthesis gas in the combustion turbine, resulting in both reduced capital costs and improved efficiency. This technology was assumed to become available for service in 2020.
16. **Nuclear:** based on designs that are currently under licensing review by the NRC and expected to reach commercial operation late in the next decade. They are characterized by passive safety systems and simpler design configurations than earlier designs. This technology was assumed to become available for service in 2020.

7.2.2 Opportunities at existing plants

Only generic resource options were considered in our capacity expansion modeling. There are a number of potential resource opportunities at GRE's existing plants that were not modeled specifically. These potential opportunities are described in Appendix D (Trade Secret).

8 RESOURCE PLANS

These are times of great change and uncertainty for energy producers, consumers, and policy makers. Rising costs for all types of generators, volatile fuel prices, and uncertainties about the magnitude and timing of future carbon regulations all are significant factors in determining what directions utilities should pursue in meeting future needs. The approach in this resource plan filing is to look at a broad range of assumptions in a number of scenarios to develop a resource plan that will be robust in meeting our objectives of reliability, cost, and environmental stewardship.

While this investigation is more informative than definitive; we have identified a preferred resource plan to provide a benchmark for planning and discussions.

8.1 Key Modeling Assumptions

Modeling provides a useful guide for the judgments necessary in planning. But in making those judgments it is important to keep in mind the assumptions and limitations that are inevitably part of any modeling effort. Our key assumptions are listed below.

1. Due to the unpredictability of market conditions, no interactions with the short-term energy market were allowed. We found it impractical to reconcile market price forecasts with varying assumptions such as fuel and CO₂ costs in a consistent-enough manner to provide meaningful results. In reality, interacting with the market would result in lower overall costs than the self-sufficient perspective taken here.
2. CO₂ costs were examined ranging from \$0/ton of CO₂ to \$4, \$10 \$30, \$50 and \$70. These values are in 2008 dollars per short ton and were escalated at 3% per year.
3. In scenarios involving CO₂ values higher than \$10 per ton, the higher values were assumed to begin in 2013.
4. The federal Production Tax Credit (PTC) for wind energy was assumed to be extended under its existing terms through 2012, after which it was assumed to be supplanted by CO₂ regulations.
5. In most scenarios, the Minnesota Renewable Energy Standard was a floor to the amount of wind added. The model was allowed to select more wind if economical.
6. All existing resources remain in service over the forecast period. This limitation is significant in scenarios with high CO₂ costs. In those scenarios baseload coal units shift to cycling operation, suggesting that they would need to be modified, retired, repowered, or retrofitted with CO₂ capture. Such changes were not included in this study and would represent additional costs in those scenarios.
7. All contracts for resources, both purchases and sales, are allowed to end at their contract term, without extension or renewal.
8. In most of the scenarios, the load forecast reflects meeting Minnesota's 1.5% Energy Conservation Policy Goal without identifying specifically how it would be met nor what costs may be incurred in doing so.
9. No price-demand elasticity was included because of the complexity of the interrelated consequences of certain cost increases. This is significant because some scenarios,

particularly those with high CO₂ costs, would result in much higher costs that would be reflected in higher rates. Since electricity costs would not be affected in isolation, the resulting effect on demand would depend on the interplay of such higher costs on other fuels, other uses of energy, housing patterns, and the economy in general.

8.2 Capacity Expansion Model

In preparing this resource plan, GRE used the Capacity Expansion Model (CEM) program produced by Ventyx, Inc. CEM was developed by Henwood Energy Services, which was acquired by Global Energy Decisions, which itself has been acquired by Ventyx. As part of an ongoing consolidation of vendors and service providers to the utility industry, Ventyx has also acquired the vendor supplying the Strategist modeling package. Strategist and CEM remain separate products at this time.

GRE uses CEM in part because it aligns with the Ventyx Power Market Advisory Service that GRE uses as one source of market and fuel price forecasts. Those forecasts and the insights gained through the processes of creating them provide a good foundation for developing a perspective on the key drivers behind future energy prices. GRE also uses CEM because it provides flexibility in modeling resources. For example, CEM is capable of optimizing wind resources without the need to hardcode specific levels of wind additions.

CEM solves for the expansion plan that minimizes the present value of revenue requirements (PVR) over the study period while meeting load balance and reserve capacity requirements. It minimizes the dispatch costs of currently available resources and determines an optimal system-wide resource expansion plan. It is capable of handling multiple expansion alternatives simultaneously for the entire system and planning horizon. GRE used the program in its linear programming mode, which finds the optimum expansion plan without constraining specific resources by size. This gave us an indication of the optimum size of our need for each resource in each year.

8.3 Study Process

GRE's resource planning process is ongoing, with studies and scenarios changing as new information becomes available and strategic decisions are made. While the study process is long and detailed, it can be simply described as verifying and updating data inputs, selecting scenarios to study, determining the specific assumptions to use in each scenario, and examining and comparing results.

8.3.1 Data Inputs

8.3.1.1 Financial

An escalation rate of 3% was used on all costs except where noted otherwise. Cost of capital and discount rate assumptions are shown in Appendix E (Trade Secret).

8.3.1.2 Forecasts

Load Forecast

As described in Section 3 and Appendix A, GRE developed an econometric load forecast (the ERAEM forecast) for 100% of the GRE member requirements as a starting point. This forecast was then adjusted as follows for use in our modeling:

1. Reductions in demand and energy to represent the growth of the eight members who have elected to fix their purchases from GRE (this adjustment was reflected in the model as a no cost resource);
2. Adders to summer peak demand associated with a 90% probability forecast (this adjustment was reflected in the model as a demand sale with no associated energy);
3. Reduced energy and demand to account for conservation greater than the historical trend in meeting the Minnesota 1.5 % Energy Conservation Policy Goal (this adjustment was reflected in the model through a modification of the load inputs to the model);
4. An increase in load growth for higher growth scenarios such as may result from plug-in hybrid electric vehicles (PHEV) or other causes (this adjustment was reflected in the model through a modification of the load inputs to the model).

See Appendix B for specific details of each adjustment.

Fuel Forecasts

Coal

The forecast of the cost of coal for the Coal Creek, Stanton, Genoa, and Spiritwood plants is an internal process that best represents mining and contract costs. The Fall 2007 Ventyx forecast for coal in North Dakota was used for all potential new coal fired generation

Oil

The Fall 2007 Ventyx forecast of oil prices was used for our existing oil fired generation.

Natural Gas

Gas prices are based on Ventyx forecasts with GRE-specific adders for locational costs. Due to great concern over the recent volatility of natural gas prices, we reran all of our scenarios to reflect updated forecasts that became available from Ventyx in mid-May, 2008. Scenarios with both expected and high natural gas prices were modeled.

Emissions Forecasts

The values for particulates in all modeling scenarios are the high Minnesota Externalities values. Expected costs to GRE of NO_x, SO₂, and Hg are expected to be higher than the Minnesota Externalities values. Therefore; Fall 2007 Ventyx forecasts were used in all modeling scenarios. CO₂ was valued at \$0, \$4, and \$10/ton. In addition scenarios using \$30, \$50, and \$70/ton were also modeled. In these scenarios \$10/ton was used until the higher values were assigned starting in 2013. These values are in 2008 dollars per short ton and all were escalated from 2008 at 3% per year.

8.3.1.3 Resources

Existing Resources

The following is a list of the major data inputs for existing resources that were verified and/or updated:

- Capacities and planning capacity factors
- Scheduled outages and forced outage rates
- Variable costs
- Heat rates and emissions outputs
- Contract dates

Future Resource Options

- Capacities and planning capacity factors
- Forced and maintenance outage rates
- Heat rates and emissions outputs
- Construction costs
- Variable and fixed costs
- Wind energy pricing consistent with GRE's most recent purchases and prices 20% higher in high wind cost scenarios
- Allowances for transmission costs

Detailed model inputs are included in Appendix E (Trade Secret).

8.3.2 Scenario Descriptions

Assumptions were held constant across the scenarios except the following:

- The cost assigned to CO₂.
- The forecast of natural gas prices.
- The cost of wind generation.
- The ability to meet the Renewable Energy Standard.
- The amount of conservation in the load forecast.
- The probability level of the load forecast.

An extensive number of scenarios were modeled to systematically examine the effects of each change in assumption. Figure 8-1 lists them. A red font indicates a change from the Scenario 3, which, as described below, was designated as our benchmark.

Figure 8-1 List of Scenario Assumptions

Assumption/ Scenario ID	Scenario Name	Forecast	1.5% Conservation	Natural Gas Forecast	CO2 \$/ton	Wind Price	RES
1	Status Quo	90%	No	Ventyx Expected Spr08 + GRE adders	\$0.00	Last RFP	No
2	SQ + RES	90%	No	Ventyx Expected Spr08 + GRE adders	\$0.00	Last RFP	Yes
2B	SQ + RES & \$10CO2	90%	No	Ventyx Expected Spr08 + GRE adders	\$10.00	Last RFP	Yes
3	Benchmark	90%	Yes	Ventyx Expected Spr08 + GRE adders	\$10.00	Last RFP	Yes
3A	Benchmark + No New Wind	90%	Yes	Ventyx Expected Spr08 + GRE adders	\$10.00	Last RFP	No Wind
4	Benchmark + zero \$ CO2	90%	Yes	Ventyx Expected Spr08 + GRE adders	\$0.00	Last RFP	Yes
5	Benchmark + \$4 CO2	90%	Yes	Ventyx Expected Spr08 + GRE adders	\$4.00	Last RFP	Yes
6	Benchmark + \$30 CO2	90%	Yes	Ventyx Expected Spr08 + GRE adders	\$10 through 2012 then \$30	Last RFP	Yes
7	Benchmark + \$50 CO2	90%	Yes	Ventyx Expected Spr08 + GRE adders	\$10 through 2012 then \$50	Last RFP	Yes
8	Benchmark + \$70 CO2	90%	Yes	Ventyx Expected Spr08 + GRE adders	\$10 through 2012 then \$70	Last RFP	Yes
9	Benchmark + high gas \$	90%	Yes	Ventyx High Spr08 + GRE adders	\$10.00	Last RFP	Yes
10	Benchmark + high gas \$ & high wind \$	90%	Yes	Ventyx High Spr08 + GRE adders	\$10 through 2012 then \$30	Last RFP	Yes
11	Benchmark + high gas \$, \$30 high wind \$	90%	Yes	Ventyx High Spr08 + GRE adders	\$10.00	+20%	Yes
12	Benchmark + high wind \$	90%	Yes	Ventyx Expected Spr08 + GRE adders	\$10.00	+20%	Yes
13	Benchmark + high wind \$ & \$30 CO2	90%	Yes	Ventyx Expected Spr08 + GRE adders	\$10 through 2012 then \$30	+20%	Yes
14	Benchmark + base case forecast	50%	Yes	Ventyx Expected Spr08 + GRE adders	\$10.00	Last RFP	Yes
15	Benchmark + PHEV forecast	90%	No	Ventyx Expected Spr08 + GRE adders	\$10.00	Last RFP	Yes

Red font identifies values different than the Benchmark study.

As a starting point, Scenario 1 included a set of status quo assumptions: a demand forecast adjusted to meet the needs of GRE's members at a 90% probability level, the expected price forecasts of fuel, zero CO₂ costs, DSM and conservation proportionate with historical levels, and no RES requirement. In this scenario the model was free to select resources based on economic assumptions without being forced to meet existing or future CO₂, conservation or renewable energy requirements.

In Scenario 3 all assumptions were the same except the following: meeting the Minnesota 1.5% Energy Conservation Policy Goal, installing wind to meet, at minimum, the RES and more if economical, and CO₂ at \$10/ton. This became our Benchmark Scenario and all of the other scenarios were compared to it.

8.3.3 Scenario Results

Due to the volume of data produced by the CEM Model, we developed a report card of key indicators to ease comparison of scenarios. The report card with results for all scenarios is included in Appendix C. The report card focuses on results for the year 2025 since that is a key year of interest with the Renewable Energy Standard reaching 25%. In this section, several key scenarios of interest are described in more detail.

Figure 8-2 is a subset of the energy breakdown summary chart included in the report card. Present here are just 2 scenarios, Scenario 3, the Benchmark scenario and Scenario 6, the Benchmark scenario with higher (\$30 instead of \$10) CO₂ costs. For the both scenarios approximately 10% of total energy is represented by the growth of the fixed members, for which GRE is not responsible. Another 10% is “supplied” by the incremental conservation needed to meet Minnesota’s 1.5% Energy Conservation Policy Goal. In Scenario 6, the higher CO₂ cost results in less energy from fossil sources and more from renewables and nuclear (as a proxy low/no CO₂ baseload resource).

The small white boxes show CO₂ emissions. With higher CO₂ costs these emissions are nearly 1/3 lower than would be the case with lower CO₂ costs.

Figure 8-2 Energy Breakdown in 2025, Scenarios 3 and 6

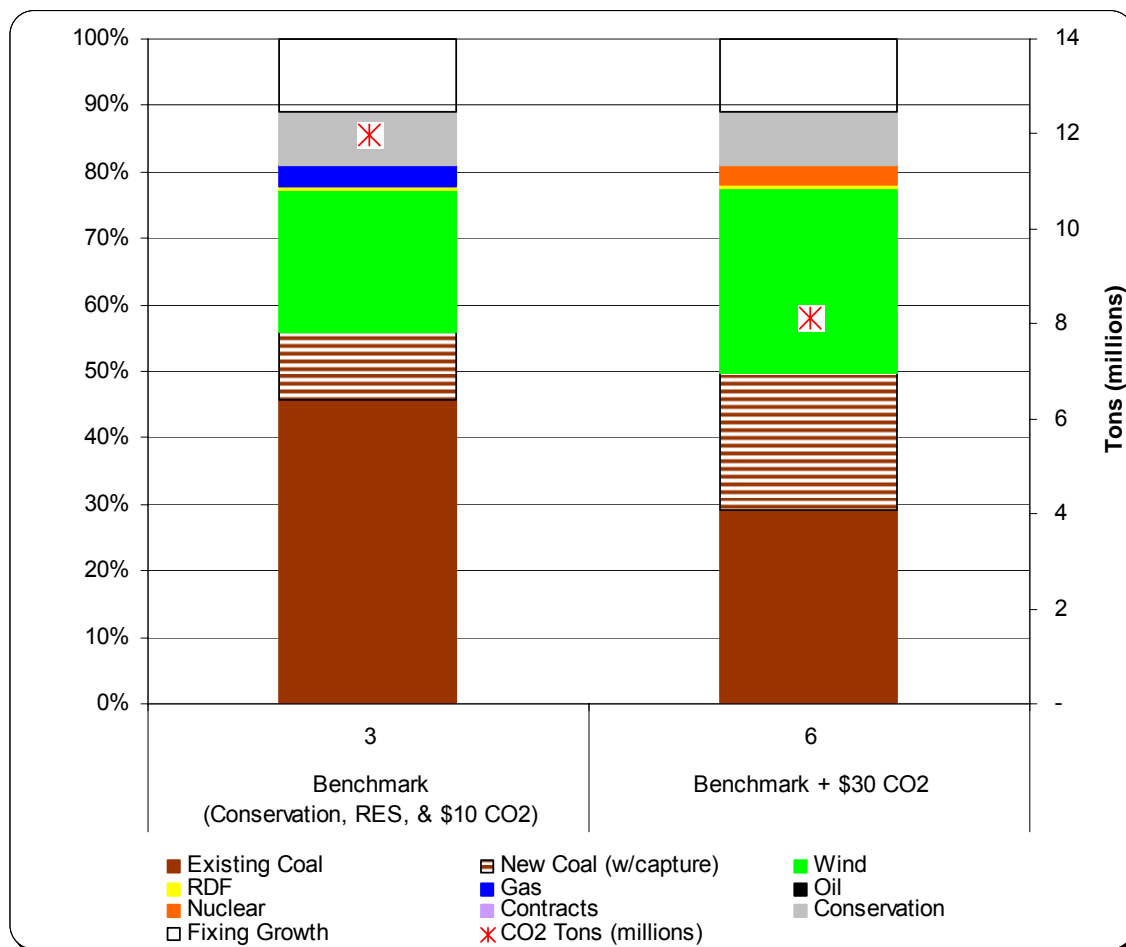


Figure 8.3 compares the same scenarios for capacity. Again the amounts due to fixing member growth and conservation are similar between the scenarios. With higher CO₂ costs, less gas fired generation is added, existing coal units produce less energy, and more low/no CO₂ baseload is added in the form of both nuclear and coal with carbon capture.

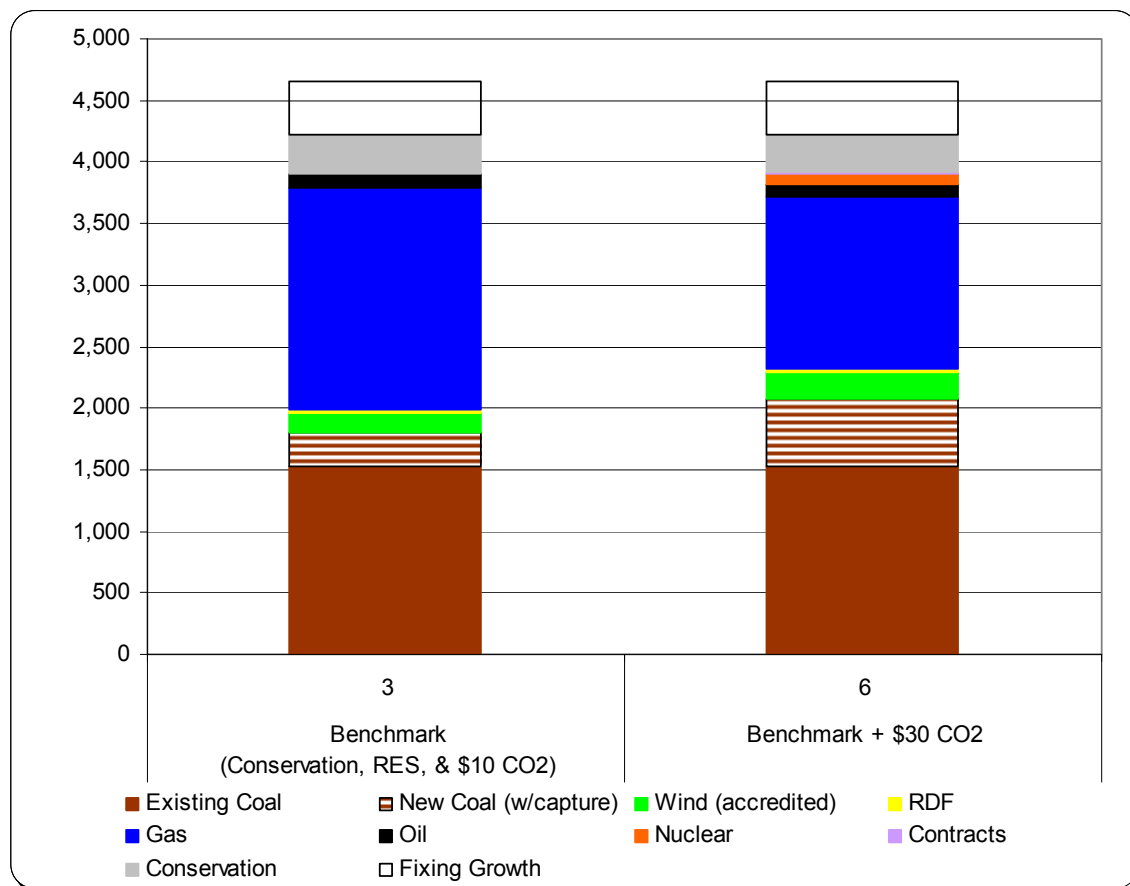
Figure 8-3 Capacity Breakdown in 2025, by Scenario

Figure 8-4 provides more detail about the differences between the scenarios. The Present Value of Revenue Requirements (PVRR) are shown, both as a total and a breakdown into cost associated with existing and new resources. The costs of CO₂, which are included in the PVRR figures, are also shown separately.

The capacity additions are broken down for various time periods and by type. With higher CO₂ costs, the results show:

- More wind additions. While the quantities suggested are unlikely to be achievable, the suggestion to add more wind sooner is clear.
- A shift from combined cycle to simple cycle natural gas fired generation. This outcome arises because at higher carbon costs even efficient gas-fired generation becomes expensive, limiting its use to peak periods.
- More low/no CO₂ baseload.

CO₂ emissions, both total and intensity, are listed at the bottom of the table and show reductions of approximately 1/3 with higher CO₂ costs.

Figure 8-4 Additional Details, Scenarios 3 and 6

Study ID		3	6	
Alternative Assumptions		Conservation \$10 CO ₂	Conservation \$30 CO ₂	
Financial (NPV \$billions) (to year 2025)	Existing Station Costs	5.589	6.157	
	Proposed Station Costs	1.884	3.092	
	PVRR	7.472	9.250	
	CO ₂ Costs	1.567	2.633	
Capacity Additions (MW)	2009-2014	Wind (nameplate)	721	1420
	2015-2019	SCGT	19	149
		CCGT	213	0
	2020-2025	Wind (nameplate)	295	0
		SCGT	272	0
		CCGT	51	0
		Baseload	273	632
	Total 2009-2025	Wind (nameplate)	1016	1420
		SCGT	291	149
		CCGT	264	0
Baseload		273	632	
Total		1844	2201	
Emissions	Million Tons CO₂ in 2025	11.988	8.120	
	CO₂ Tons/MWh in 2025	0.72	0.49	

Sets of seven year-by-year charts are shown for Scenarios 3 and 6 in Figures 8-5 through 8-11 and 8-12 through 8-18 respectively and for all of the scenarios in Appendix C.

The seven charts show:

1. Energy Sources
2. Projected Renewable Energy, including Renewable Energy Standard
3. Peak Obligations vs. Capacity
4. Resource Additions (annual)
5. Resource Additions (cumulative)
6. Natural Gas Burn
7. CO₂ Emissions

The following series of graphs show results for the Benchmark (\$10 CO₂) scenario, Scenario 3. Figure 8-5 shows wind generation meeting our new energy needs until 2020, when we assume the low/no carbon baseload becomes available, represented here by coal with carbon capture.

Figure 8-5 Benchmark Scenario Energy Generation by Year

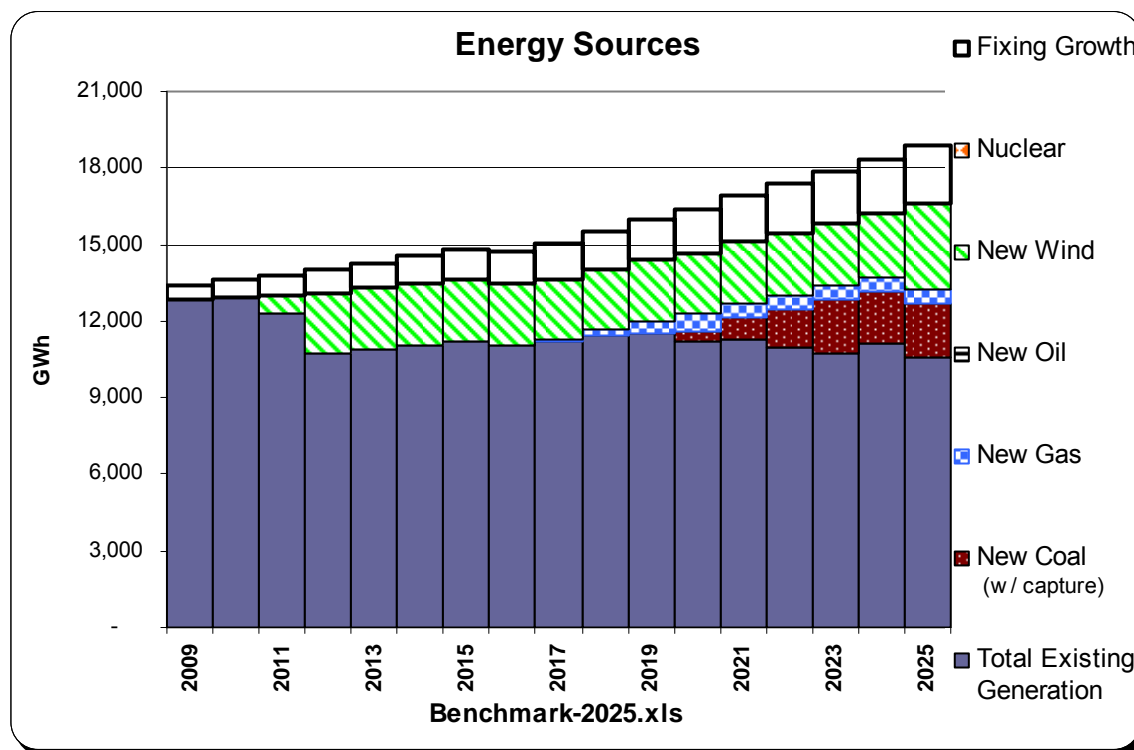


Figure 8-6 below shows the level of renewable energy generation expected in the Benchmark scenario. In this scenario, the model treats the Renewable Energy Standard as a floor and may select more wind if economical. A key modeling assumption is that the current production tax credit (PTC) will be in effect through 2012. The effect of this assumption is to add almost all wind resources before 2012. While this result is likely unachievable in practice, it illustrates the sensitivity of the results to wind energy cost assumptions.

Figure 8-6 Benchmark Scenario Projected RES Compliance

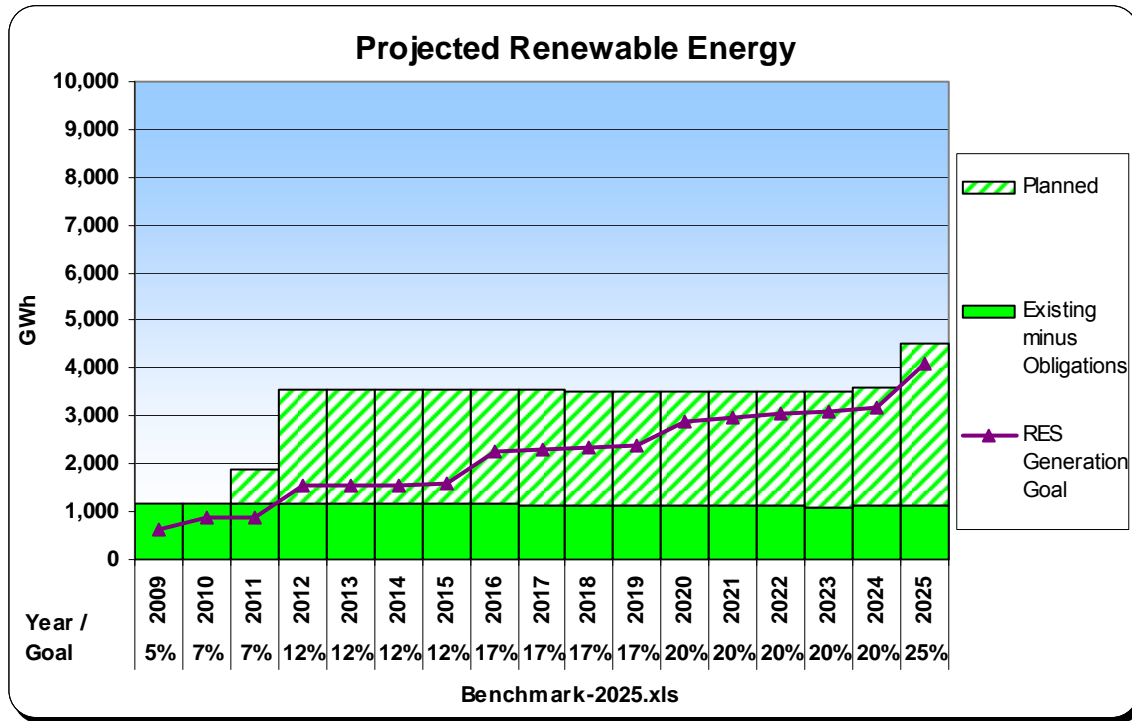


Figure 8-7 below illustrates the summer capacity situation for this scenario over time.

Figure 8-7 Benchmark Scenario Resource Situation

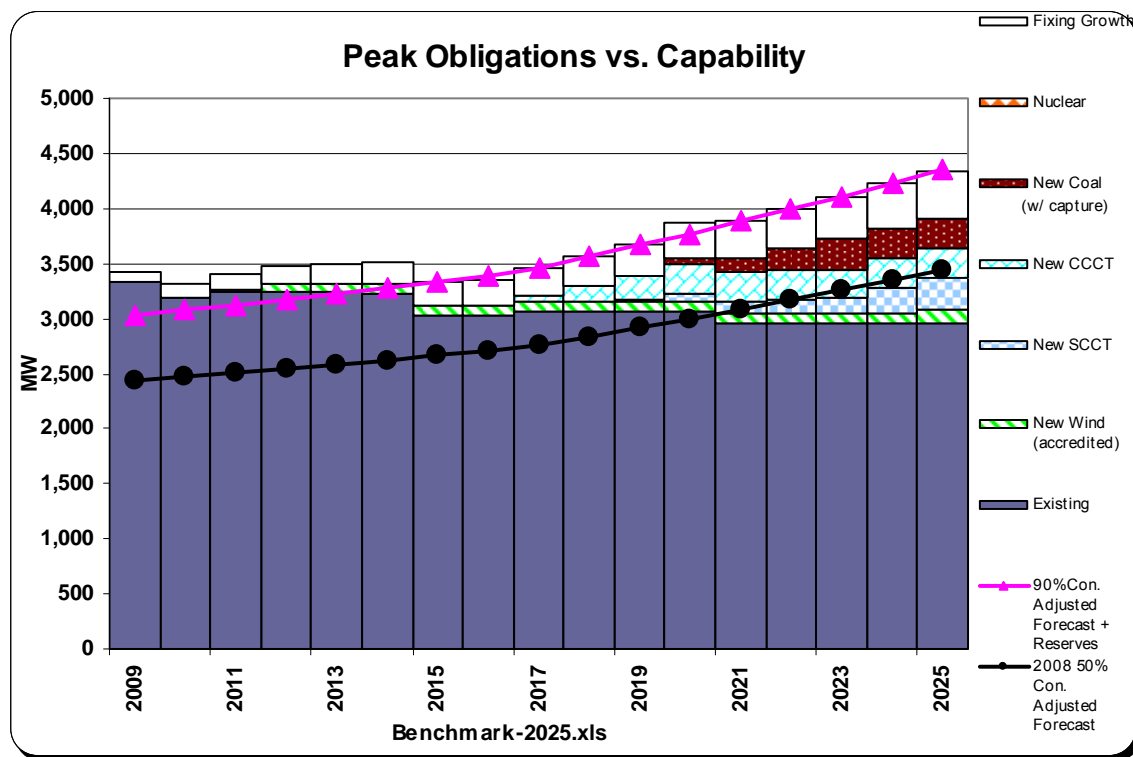


Figure 8-8 below illustrates when resource additions are made on an annual basis in the Benchmark scenario. It starkly illustrates how sensitive wind additions are to price and the continuation of the production tax credit (PTC), with the strong “front loading” of the wind additions through 2012, when the PTC is assumed to expire.

Note that the coal additions have carbon capture and are representative of low/no CO₂ baseload technologies, which are not assumed to be available until 2020.

Figure 8-8 Benchmark Scenario – Resource Additions by Year

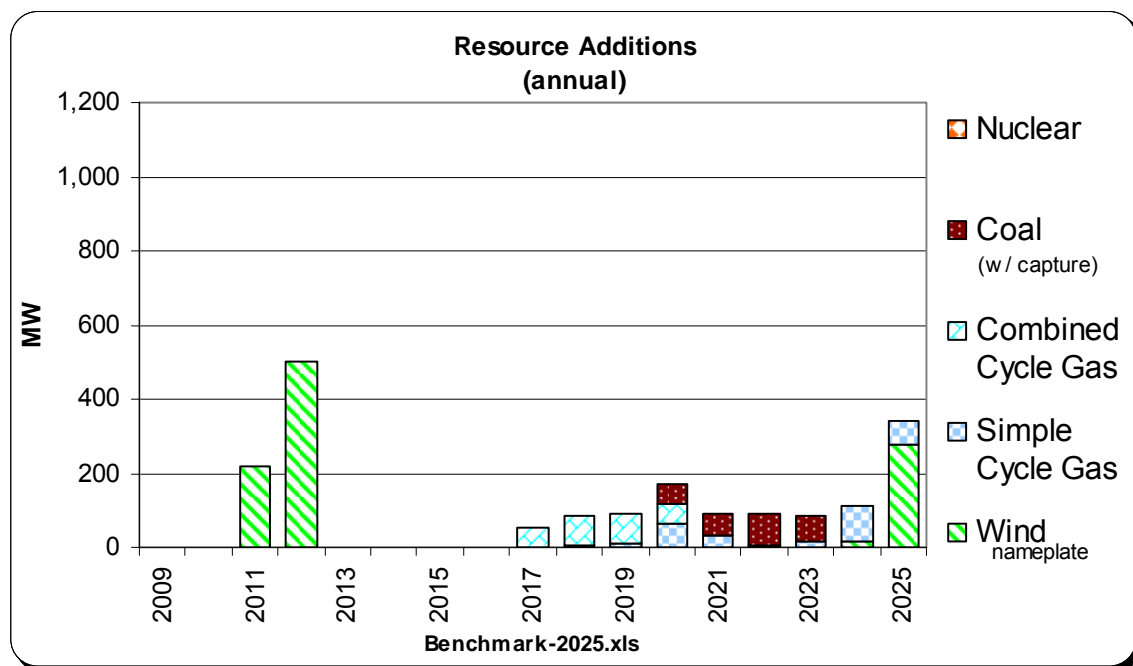


Figure 8-9 below illustrates the resource capacity additions on a cumulative basis.

Figure 8-9 Resource Additions (cumulative)

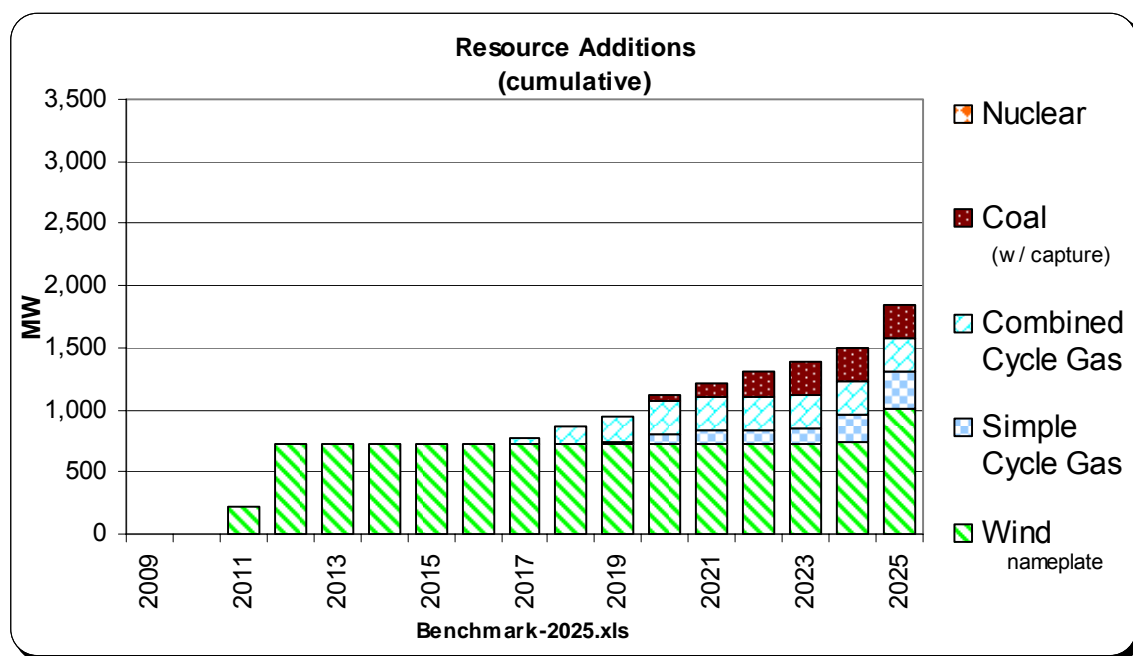


Figure 8-10 below illustrates the natural gas burn (in absolute terms) year by year for the Benchmark scenario. In Appendix C, we show the percentage of energy produced from natural gas in 2025 for each scenario. In the Benchmark scenario, 3% of energy comes from natural gas in 2025. For the other scenarios the percentages range from 0% to 5%. As Figure 8-10

below illustrates more gas is burned in some years before 2025 than in 2025, reflecting the addition of more low/no carbon generation post 2020.

Using natural gas to supply up to 5% of our energy needs is reasonable. Including significant amounts of wind resources will require additional gas fired generation to deal with wind's intermittency. Natural gas does present some significant challenges in dealing with price volatility and volume volatility. The volatility of natural gas prices is well known. But volume volatility presents as additional risk. GRE's gas generation consists of simple cycle peaking units. The dispatch of these units is strongly influenced by weather because our load is very weather sensitive. In a cool summer we may burn very little gas while in a hot summer our gas consumption increases dramatically. This volume volatility combined with volatile prices makes hedging our gas costs particularly challenging. In addition, MISO rules do not permit us to recover our hedging costs via the MISO market.

Figure 8-10 **Natural Gas Burn**

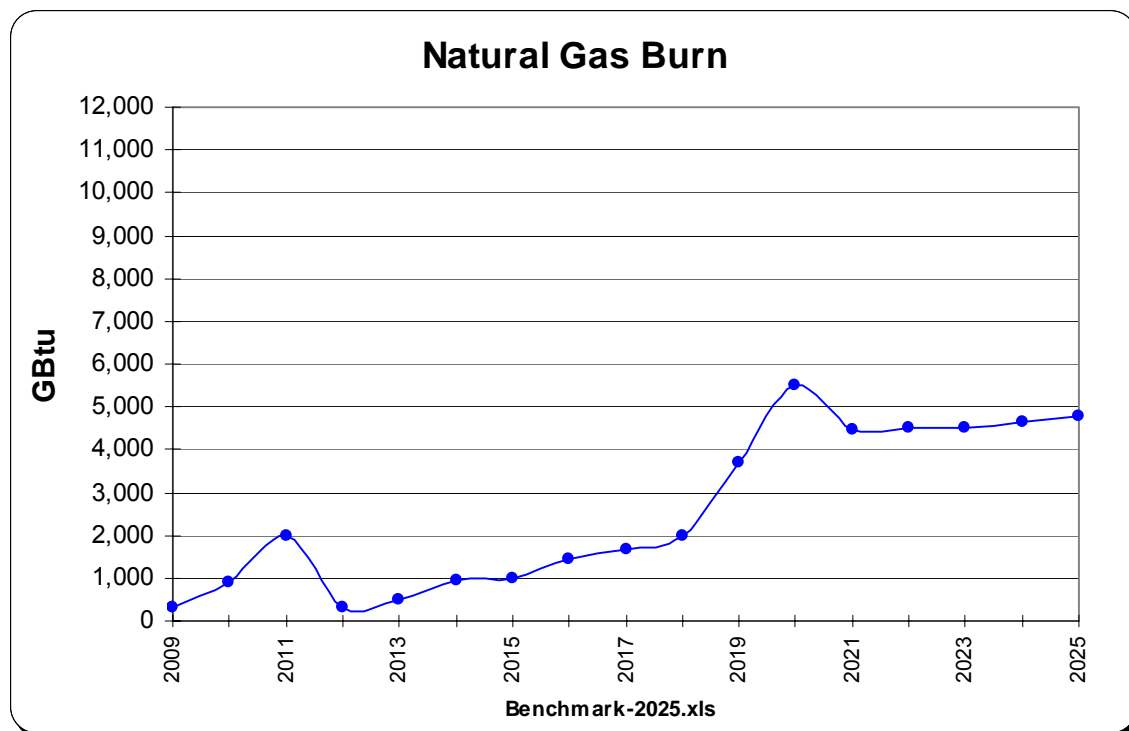
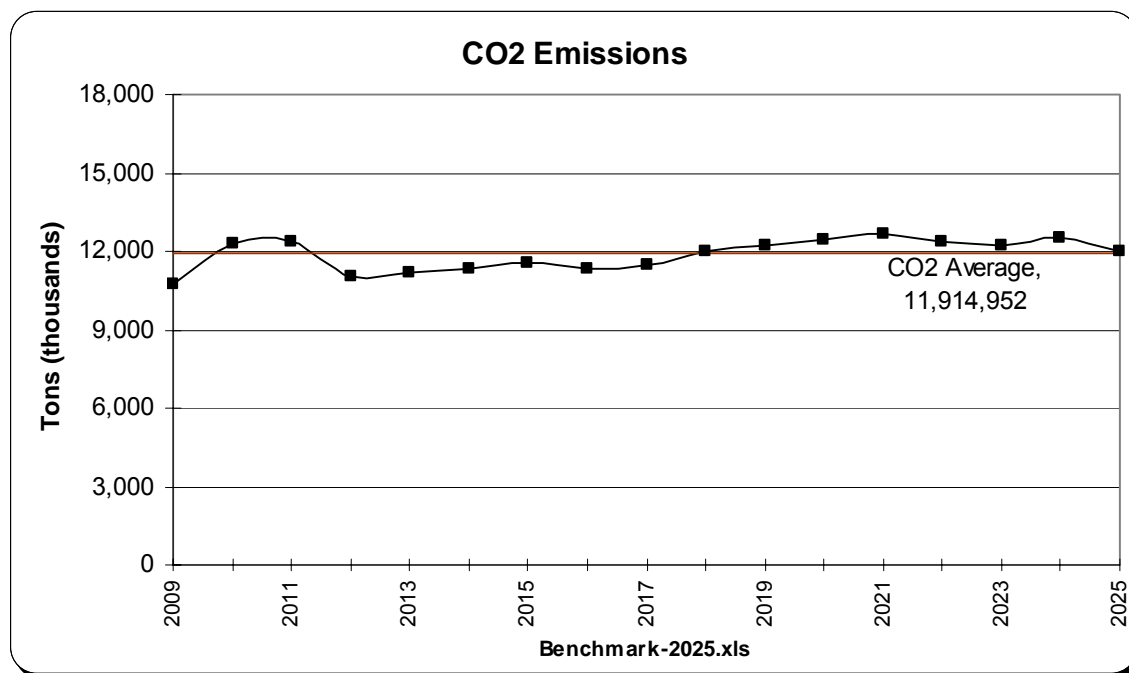


Figure 8-11 below illustrates CO₂ Emissions over time. At \$10/ton, there is relatively little impact on overall CO₂ emissions. The major wind addition in 2012 suppresses CO₂ emissions significantly but then tends to drift higher until approximately 2020.

Figure 8-11 CO₂ Emissions

The following seven figures show the results for Scenario 6, the Benchmark scenario with \$30/ton CO₂ costs instead of \$10/ton. All other assumptions are held constant to illustrate the impact of higher CO₂ costs.

Figure 8-12 through 8-16 show that this scenario's higher CO₂ costs result in more early wind additions. The 25% level of renewable energy is met very early, reflecting both the importance of low/no carbon resources in a higher CO₂ cost regime and the significance of the Production Tax Credit. Adding this much wind this quickly is unlikely to be feasible due to equipment supply and transmission limitations (the model was not restricted in the amount of wind that it could add in any year), but the direction to aggressively add wind suggested by this scenario is clear.

At higher CO₂ costs, more low/no carbon baseload resources (represented as coal with carbon capture and nuclear) are selected as soon as those low carbon options became available for selection in 2020.

There is a significant reduction in energy produced by existing units and less energy is produced from gas, with the gas resources added later than in the Benchmark scenario. The reason for this is likely that GRE already has a large fleet of modern gas peaking units with relatively flexible operating characteristics that can be used (in this self-sufficient modeling structure) to accommodate the intermittency of the large additions of wind resources in this scenario.

Figure 8-12 Energy Sources – Benchmark +\$30 CO₂

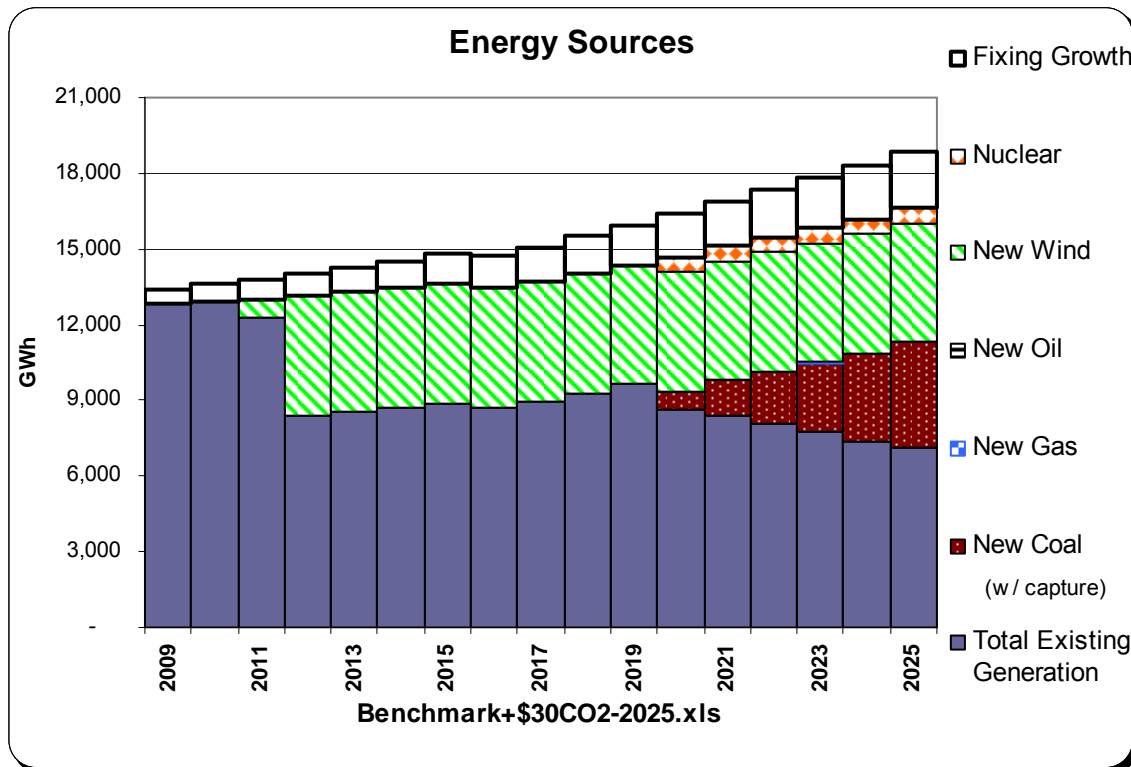


Figure 8-13 Projected Renewable Energy – Benchmark +\$30 CO₂

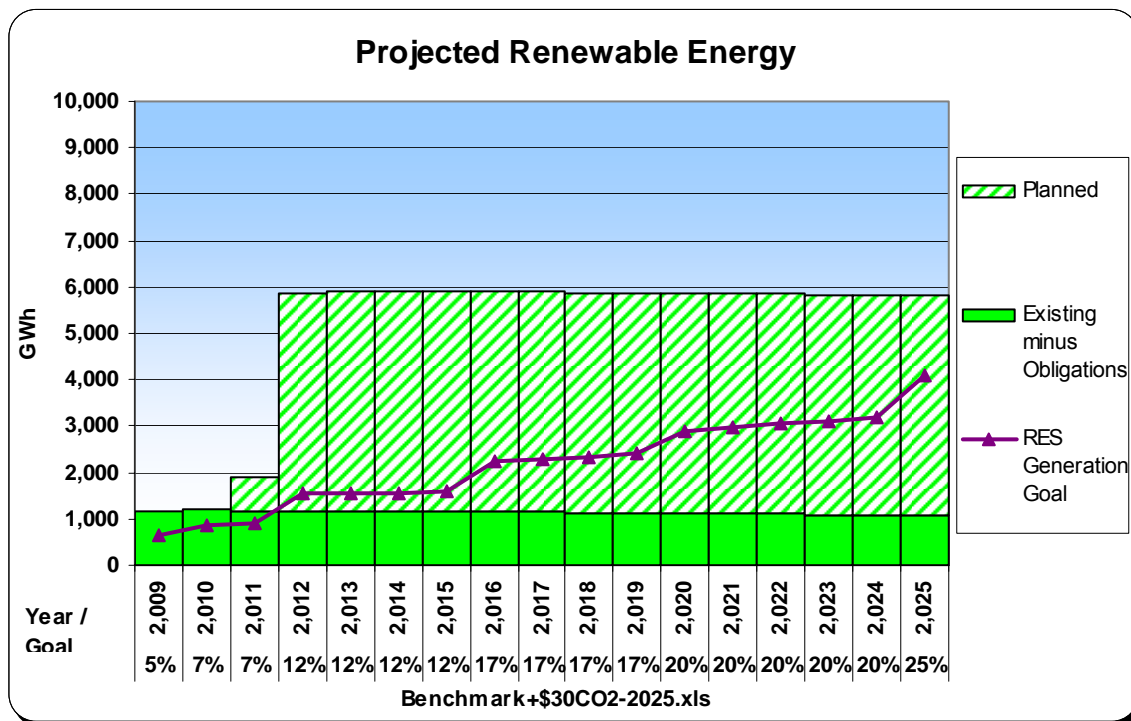


Figure 8-14 Peak Obligations vs. Capability – Benchmark +\$30 CO₂

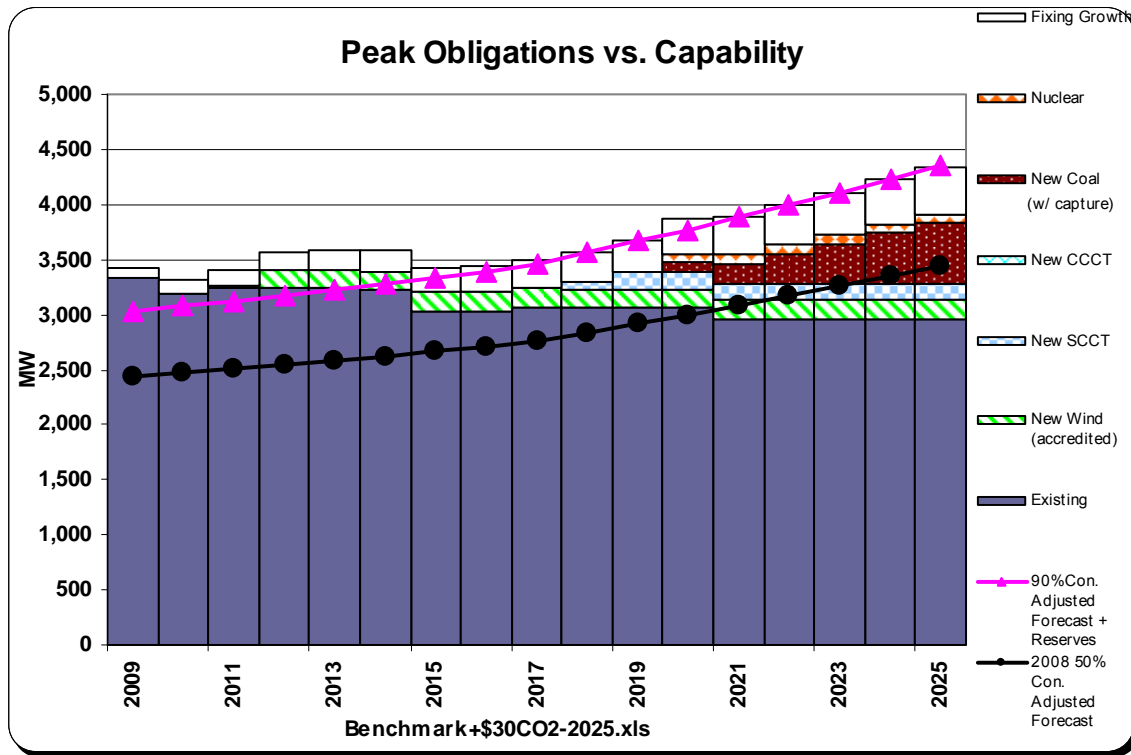


Figure 8-15 Resource Additions (annual) – Benchmark +\$30 CO₂

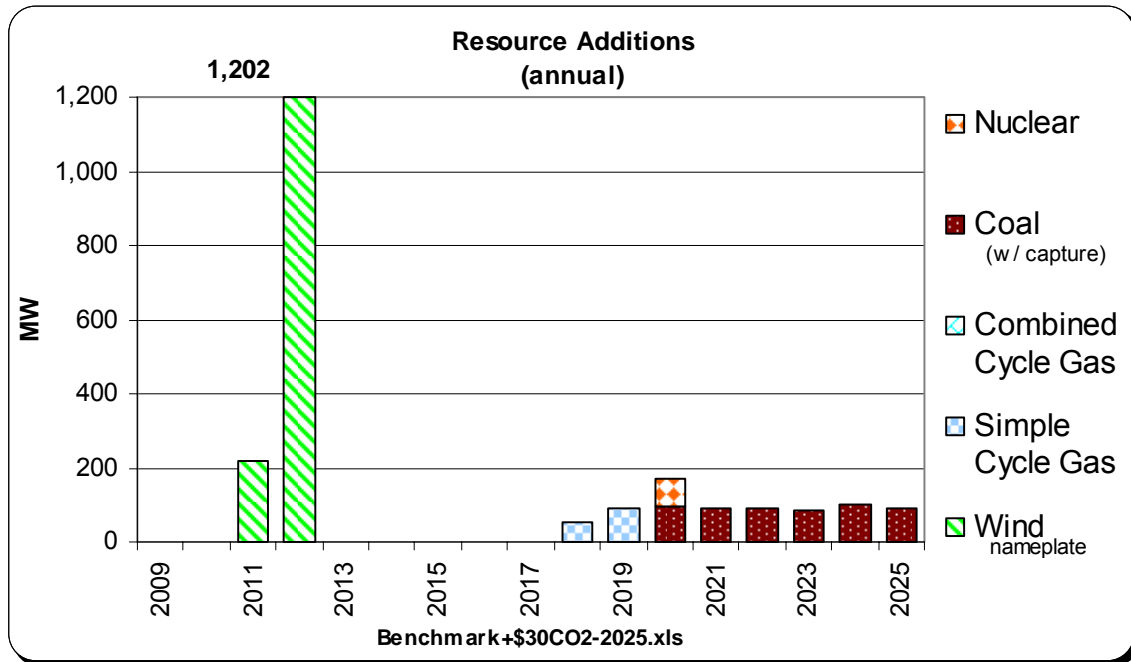


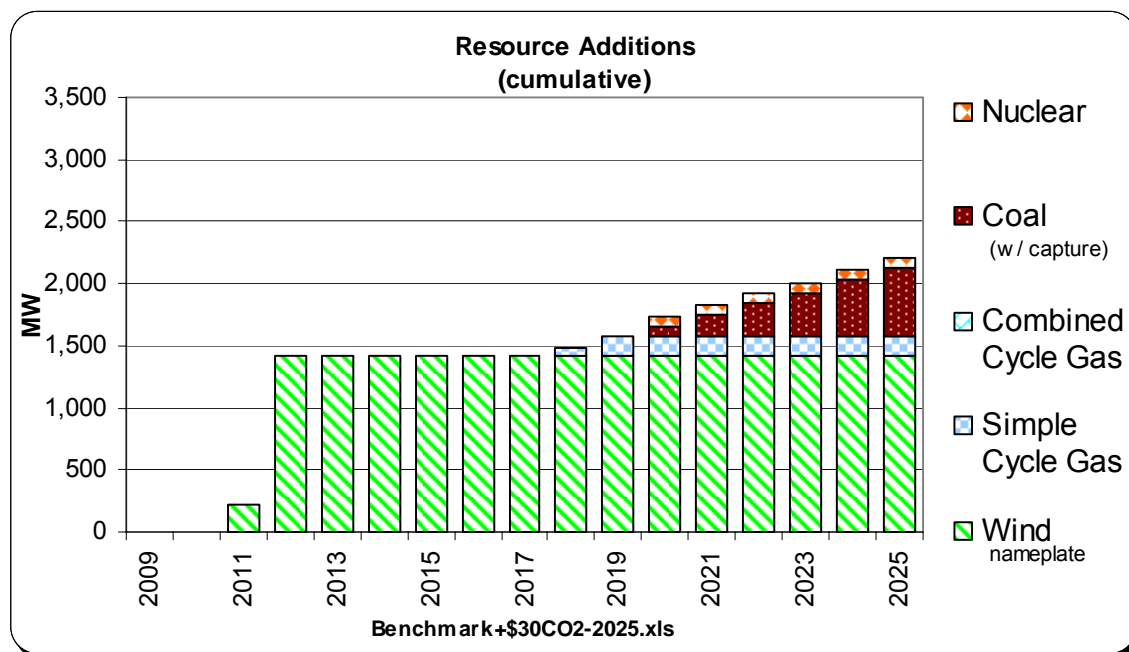
Figure 8-16 Resource Additions (cumulative) – Benchmark+\$30 CO₂

Figure 8-17 below shows the reduced natural gas burn resulting from significantly more wind added than in the Benchmark scenario. Later in the study period it is further reduced with the addition of coal with carbon capture and nuclear. In this scenario, gas units are relied upon primarily to make up for wind's intermittency, with more energy served by the greater amount of wind resource.

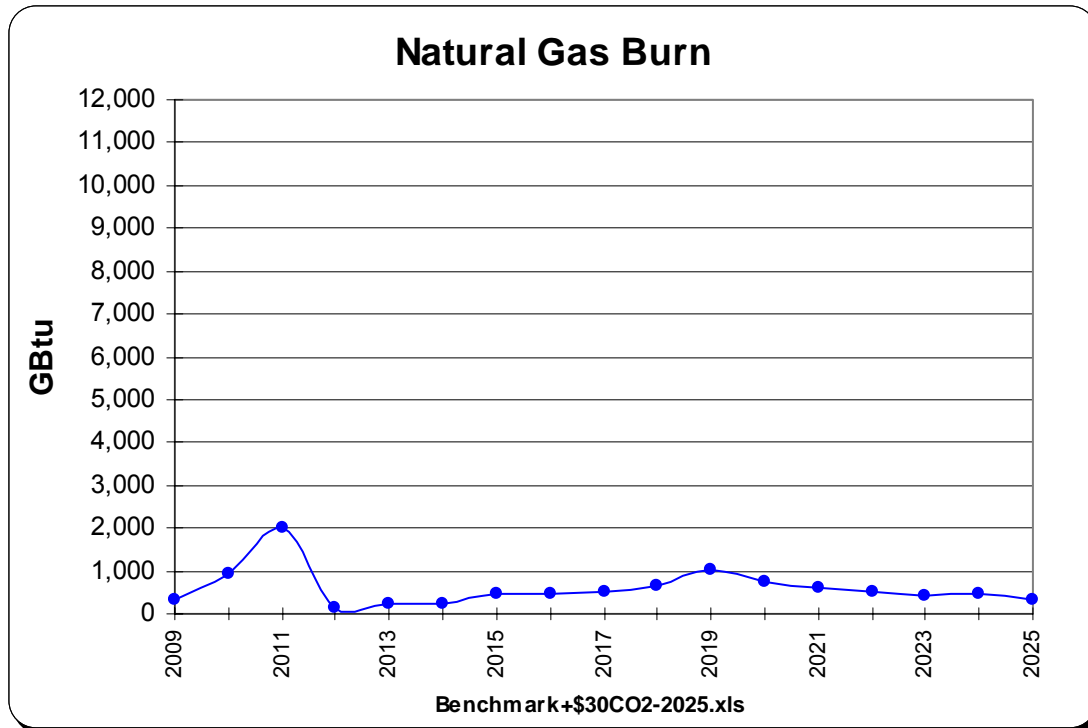
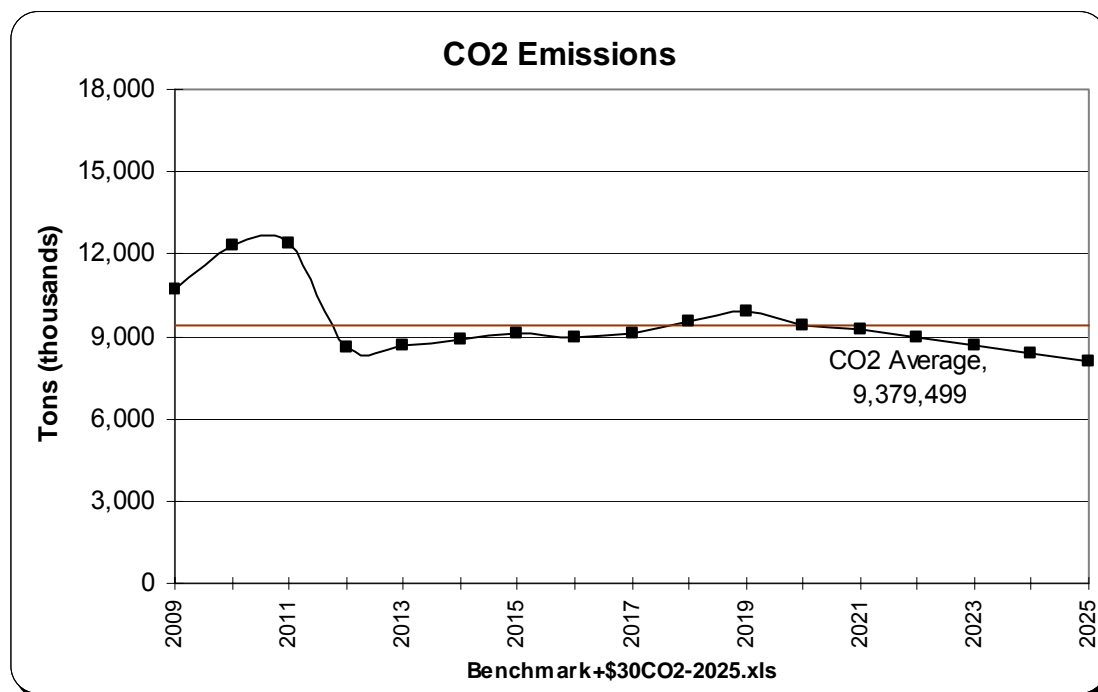
Figure 8-17 Natural Gas Burn – Benchmark +\$30 CO₂

Figure 8-18 illustrates a significant reduction in total CO₂ emissions with the large early additions of wind, reaching a new equilibrium that is approximately 25% lower than in the Benchmark scenario.

Figure 8-18 CO₂ Emissions – Benchmark +\$30 CO₂

The remaining figures in this section illustrate the effects of changes in assumptions other than carbon costs.

Figure 8-19 compares the Benchmark (Scenario 3) to a scenario with higher loads (Scenario 2B). The result is more resources of the same types, but with peaking shifted earlier in time and proportionally slightly less wind and more low/no CO₂ baseload overall. With the higher load, emissions and the total cost increase due to the greater amount of resources added. Note that the PVRRs are not directly comparable as proxies for rate impacts because of the differences in load.

Figure 8-19

StudyID		3	2B	
Alternative Assumptions		Conservation \$10 CO2	High Load \$10 CO2	
Financial (NPV \$billions) (to year 2025)	Existing Station Costs	5.589	5.691	
	Proposed Station Costs	1.884	2.643	
	PVRR	7.472	8.334	
	CO2 Costs	1.567	1.596	
Capacity Additions (MW)	2009-2014	Wind (nameplate)	721	925
	2015-2019	SCGT	19	225
		CCGT	213	317
	2020-2025	Wind (nameplate)	295	199
		SCGT	272	185
		CCGT	51	0
		Baseload	273	439
	Total 2009-2025	Wind (nameplate)	1016	1124
		SCGT	291	410
		CCGT	264	317
		Baseload	273	439
		Total	1844	2290
Emissions	Million Tons CO2 in 2025	11.988	12.003	
	CO2 Tons/MWh in 2025	0.72	0.66	

Figure 8-20 compares the Benchmark (Scenario 3) to scenarios with:

- higher gas prices (Scenario 9), and
- higher wind prices (Scenario 12).

The primary effect of higher gas prices is to add less combined cycle generation and instead add more peaking capacity and low/no CO₂ baseload resources. Gas combined cycle units would not be utilized as much at higher gas prices.

With higher wind prices the ultimate resource mix remains relatively unchanged because of the 25% Renewable Energy Standard, however less wind is added ahead of the requirements of the RES.

Figure 8-20

StudyID		3	9	12	
Alternative Assumptions		Conservation \$10 CO2	Conservation \$10 CO2 High Gas Prices	Conservation \$10 CO2 High Wind Prices	
Financial (NPV \$billions) (to year 2025)	Existing Station Costs	5.589	5.631	5.678	
	Proposed Station Costs	1.884	1.893	2.062	
	PVRR	7.472	7.524	7.740	
	CO2 Costs	1.567	1.543	1.589	
Capacity Additions (MW)	2009-2014	Wind (nameplate)	721	727	641
	2015-2019	SCGT	19	66	8
		CCGT	213	165	234
	2020-2025	Wind (nameplate)	295	289	376
		SCGT	272	295	280
		CCGT	51	0	30
		Baseload	273	394	275
	Total 2009-2025	Wind (nameplate)	1016	1016	1017
		SCGT	291	361	288
		CCGT	264	165	264
Baseload		273	394	275	
Total		1844	1936	1844	
Emissions	Million Tons CO2 in 2025	11.988	11.406	11.975	
	CO2 Tons/MWh in 2025	0.72	0.69	0.72	

8.4 Modeling Conclusions

After considering the modeling results, we draw the following conclusions:

- Wind and gas resources (simple cycle or combined cycle combustion turbines) should suffice for the first ten years of the planning period; additional baseload resources will be needed in the 2020 timeframe.
- The optimal amount and timing of wind resources is very sensitive to the cost of wind energy, including the Production Tax Credit.
- GRE's large fleet of modern gas fired peaking units has relatively flexible operating characteristics that can be used to accommodate the intermittency of additional wind resources.
- No new coal is selected before 2020 unless either the Renewable Energy Standard or the Minnesota 1.5% Energy Conservation Policy Goal is not met. In any scenario with carbon costs of \$10/ton or higher the only coal resources selected are those that include carbon capture.
- At high CO₂ costs (greater than \$30/t):
 - existing coal plants no longer are baseloaded; they shift to a cycling operation mode which suggests a need to retire or repower them, or add carbon capture;
 - nuclear or coal w/ carbon capture become more cost effective than gas; and

- costs (and therefore rates) increase dramatically unless offset by emission allowances or some other form of credits.
- Although the model selects nuclear or coal with carbon capture in various scenarios to meet long-term baseload needs, there is no obvious “winner”. Nuclear, coal with carbon capture, or other baseload resources with low or no CO₂ emissions (such as Manitoba Hydro) remain candidates to meet this need.

8.5 Preferred Plan

The resources selected in the Benchmark scenario, which includes conservation and carbon costs of \$10/ton, are fairly representative of the resources added in most of the scenarios. Thus we have selected those resources as our preferred plan. Figures 8-23 and 8-24 illustrate the annual and cumulative resources selected in the Benchmark scenario. Note that the coal resources included in these charts include carbon capture and, as noted above, should be interpreted as representing a need for baseload resources with low or no CO₂ emissions, which could be met with nuclear, coal with carbon capture, hydro, or a combination thereof.

Figure 8-21

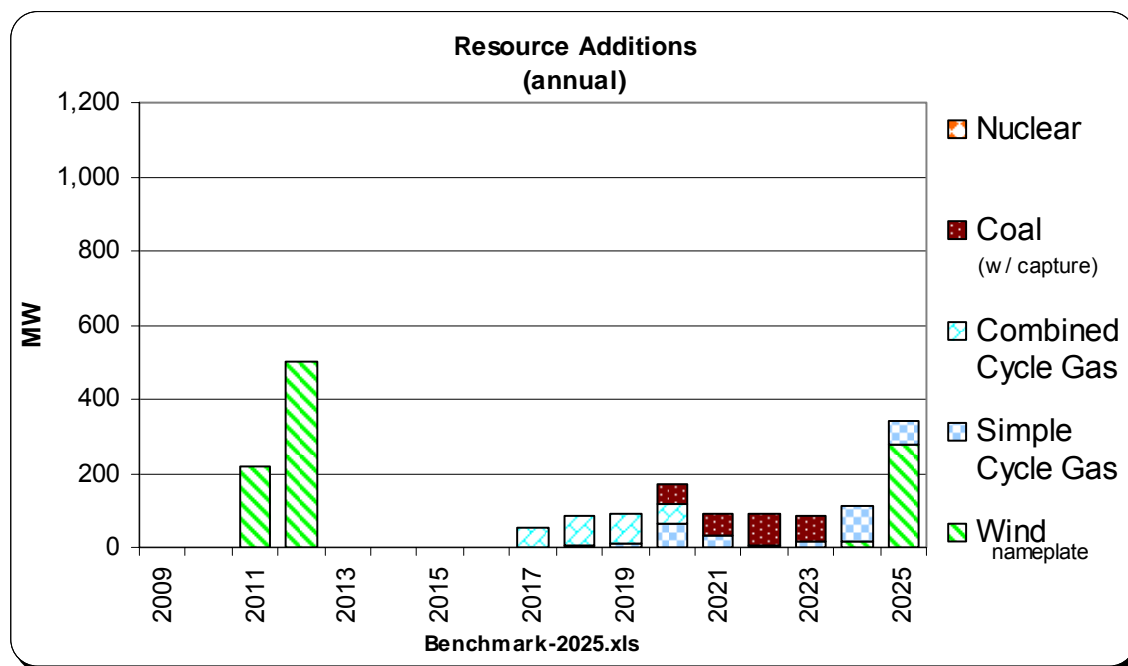
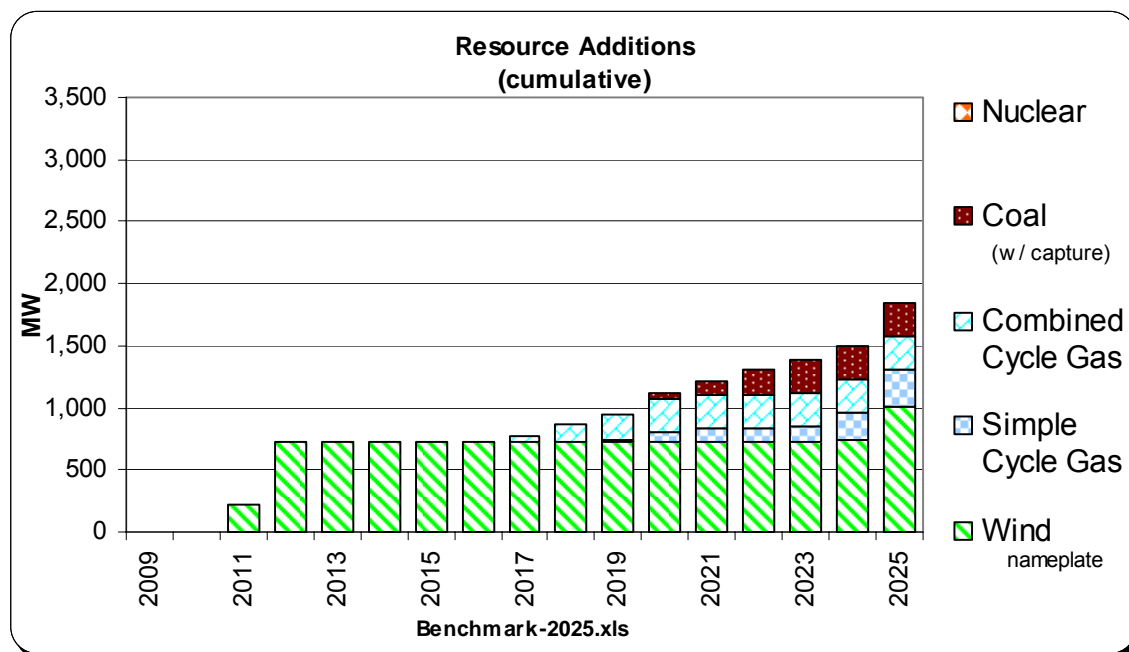


Figure 8-22



In addition to the resources shown in the charts above, our preferred plan includes the following:

- Aggressively pursue conservation / efficiency to meet Minnesota's 1.5% Energy Conservation Policy Goal.
- To the extent practicable, add wind resources while the Production Tax Credit is in effect.
- Add combustion turbine or combined cycle resources depending on energy market expectations.
- Pursue physical and financial gas hedging strategies.
- Investigate energy storage options (both utility-scale and customer-scale) to address wind integration issues and market price swings.
- Pursue unique opportunities for low CO₂ resources such as biomass projects, solar, combined heat and power projects, and efficiency improvements in existing plants.
- Begin now to develop future baseload options with low or no CO₂ emissions, such as nuclear, coal with carbon capture, and Manitoba Hydro.
- Consider the implications of future CO₂ costs on the dispatch of existing coal units.
- Adjust as new information becomes available and circumstances change.

9 TRANSMISSION

9.1 Background

GRE is both a transmission user and a transmission provider. Through a combination of GRE-owned transmission, transmission service through the Midwest Independent Transmission System Operator (MISO), and legacy contracts, GRE delivers power and energy from its generating resources to the loads of its member cooperatives as well as engages in power transactions with others.

GRE owns and maintains significant transmission resources, listed in Figure 9-1.

Figure 9-1 GRE Transmission Facilities

GRE TRANSMISSION FACILITIES	
Voltage	Miles
≤69-kV	2,944
115-kV	381
161-kV	49
230-kV	523
345-kV	75
500-kV	70
Total	4,042

GRE's member distribution cooperatives own the substations that connect their distribution systems to the transmission system.

GRE's transmission facilities were developed in close coordination with other utilities in the area. Because of intertwined service territories, many of GRE's loads are served from transmission facilities owned by adjacent utilities¹⁰ and vice versa. GRE and these utilities have turned functional control over most of these transmission facilities over to MISO. MISO provides transmission service on them pursuant to its Open Access Transmission and Energy Markets Tariff (TEMT). GRE uses Network Integration Transmission Service under the TEMPT for deliveries to its member cooperatives.

Certain legacy agreements remain in place and are grandfathered under the TEMT, including (1) GRE's transmission arrangements to deliver power and energy to and from Manitoba Hydro; and (2) the transmission arrangement to deliver the output of Stanton Station to Xcel and Otter

¹⁰ Northern States Power Company d/b/a Xcel Energy, Minnesota Power, Otter Tail Power Company, Southern Minnesota Municipal Power Agency, and International Transmission Company / Alliant Energy.

Tail Power in North Dakota in return for their supply of power and energy to GRE loads in Minnesota. Several other grandfathered transmission agreements¹¹ remain in place for joint use, load service, and/or delivery in certain local areas. GRE owns a 436-mile ±400kV direct current transmission line that delivers the output of Coal Creek Station to Minnesota and is classified as a generation outlet not under the MISO tariff.

9.2 Transmission Planning

Although the regional transmission system is generally adequate to meet current needs, expansion will be critical to meet future load growth and to support increasing development of energy resources such as wind that are distant from load centers.

The electric grid is heavily interconnected and must be evaluated, operated, and expanded in a coordinated manner to assure reliability and cost-effectiveness. GRE's transmission planning is closely coordinated with other organizations. GRE is a member of and participates directly in several regional entities:

- MISO, which in addition to administering the TEMT, also has responsibilities for regional transmission planning and expansion as part of its role as a FERC-recognized Regional Transmission Operator. Further information about MISO is available on-line at www.midwestiso.org. MISO's transmission expansion plans (MTEP-07 being the most-recent approved plan) are also available at that web site under the "Planning" tab.
- The Midwest Reliability Organization (MRO), an organization of regional utilities established to develop regional reliability standards and ensure compliance with standards of the North American Electric Reliability Corporation (NERC) as well as its own. Further information about MRO is available on-line at www.midwestreliability.org and about NERC at www.nerc.com.
- The Mid-continent Area Power Pool (MAPP), which has historically provided resource pooling and transmission coordination functions for its members across a large part of the upper Midwest. Over time, these functions are being transitioned to MISO as they evolve, at least for GRE. Further information about MAPP is available on-line at www.mapp.org.
- The Minnesota Transmission Owners (MTO) group, a consortium of 14 sponsoring utilities and three participating government agencies, fulfills the utilities statutory obligations for transmission planning in the state of Minnesota. These obligations include the development of the Minnesota Biennial Transmission Plan, as well as studies associated with meeting the Minnesota Renewable Energy Standard (RES) and the Distributed Renewable Generation (DRG) study requirements. Further information about the MTO group is available at www.MinnElecTrans.com.
- CapX 2020, a joint initiative of eleven regional transmission utilities to develop a long-range vision and extra high voltage transmission expansion projects to ensure that load in the region can be served reliably, provide outlet capability for renewable and other generation additions and facilitate energy markets. As a first phase of transmission expansion, the CapX 2020 utilities are pursuing Certificates of Need and route permits for four transmission lines:

¹¹ Counterparties include Hutchinson Utilities Commission, Willmar Municipal Utilities, and Western Area Power Authority.

- The **Twin Cities -La Crosse 345 kV Project** is an approximately 150-mile transmission line project between the southeast corner of the Twin Cities, Rochester and La Crosse, Wisconsin. This project also includes two new 161 kV transmission lines from a new Rochester Substation into Rochester.
- The **Twin Cities - Fargo 345 kV Project** is an approximately 250-mile, 345 kV transmission line between Monticello, St. Cloud, Alexandria and Fargo, North Dakota.
- The **Twin Cities - Brookings County 345 kV Project** is an approximately 200-mile, 345 kV transmission line between the southeast corner of the Twin Cities and Brookings County, South Dakota. This project also includes a 25-mile, 345 kV segment from Marshall to a new Hazel Creek Substation in the Granite Falls area, and an eight- to 10-mile, 230 kV transmission line from Hazel Creek to the Minnesota Valley Substation in Granite Falls.
- The **Bemidji - Boswell 230kV Project** is a 68 mile, 230 kV transmission line project from the Wilton substation near Bemidji to the Boswell substation near Grand Rapids.

CapX 2020 and the MTO group are also engaged in several planning studies that will provide an updated vision of the transmission system to meet needs further into the future. That includes delivering renewable energy in quantities sufficient to meet the milestones of the RES and also the renewable energy requirements of neighboring states. The studies are being closely coordinated with MISO, neighboring transmission owning utilities, the Minnesota Office of Energy Security and a diverse group of stakeholders formalized as the Technical Review Committee. MISO also has numerous studies underway with similar objectives, but that consider a broader geographic area. The CapX 2020 utilities actively participate in those studies. The first four studies listed below will provide a roadmap for transmission expansion that is efficient and assures that subsequent projects will integrate well, meet future needs and provide flexibility for changing conditions.

- Vision Study 2016: Produce an updated Vision Plan that addresses reliability-driven needs and also emphasizes the transmission requirements to meet the MN RES 2016 milestone and regional renewable energy supply needs.
- Vision Study 2025: Similar to Vision Study 2016, but focused transmission to meet the MN RES 2025 milestone, renewable energy supply needs for the region and broader market areas, future baseload generation needs and a possible new higher voltage transmission overlay.
- Generation and Transmission Optimization Study: Analyze the tradeoffs between locating generation, primarily renewables, closer to load centers which would require less transmission versus locating it in areas further from the load centers which may have certain offsetting advantages, such as better average wind speeds.
- Distributed Renewable Generation Study: Identify locations across greater MN where renewable generation installations between 10 and 40 MW can be added and fully utilize existing transmission capacity while minimizing the need for transmission upgrades and expansion. The study is being conducted in two phases, each analyzing adding 600 MW of distributed generation. More information about the DRG study can be found at <http://www.puc.state.mn.us>.

- Corridor Study: Determine if the existing 230 kV line from the Granite Falls to Panther to Blue Lake (Chaska) substations should be upgraded to a higher voltage. Previous studies have shown that this line significantly limits transfers from the west, particularly from generation in the Buffalo Ridge area and in eastern South Dakota.

Further information about CapX 2020, the proposed projects, and studies is available on-line at www.capx2020.com.

- Subregional Planning Groups (SPGs) meet regularly to provide a forum for coordination and discussion of transmission issues and proposed projects among participating utilities and other interested stakeholders.

9.3 Reporting of Transmission Plans

GRE's transmission plans and those of other regional utilities are reported in considerable detail within the following planning documents:

- Minnesota Transmission Owners *2007 Biennial Transmission Report and Renewable Energy Standards Report*, filed November 1, 2007 in Docket E999/M-07-1028 pursuant to Minn. Stat. § 216B.2425. This report and additional information is available on the Minnesota Electric Transmission Planning website, www.minnelectrans.com.
- *MISO Transmission Expansion Plan 2007*, available at the MISO website, www.midwestiso.org, under the "Planning" tab.

9.4 Issues Inhibiting Transmission Development for Energy Resources

The planning process for new transmission is done on a regional basis, overseen by MISO, rather than being integrated with generation planning within individual utilities. At any given time, many studies are underway to identify transmission facilities required to deliver the output of possible new generating resources on a generic basis. But transmission plans for specific generating projects are not developed until those projects work their way through the first-come, first-served MISO generator interconnection queue. This leads to uncertainty about the cost and availability of transmission for potential generating projects, which in turn leads to uncertainty about which generating projects will actually get built. Combined with a wave of interest in potential new wind projects, the result has been a dysfunctional interconnection process. MISO is proposing a revised generation interconnection process that provides a fast-track for low-impact connections and broader regional planning for large-scale projects.

Uncertainties about cost allocations further complicate the development of transmission infrastructure. The current methodology for recovering transmission investments generally assigns costs to customers within a transmission zone, with some provisions for direct assignment. This has created barriers to the development of transmission projects that deliver power across multiple zones and transmission projects that address multiple needs (such as reliability, generator outlet, and market economies). MISO and other groups are investigating better methods for identifying benefits and assigning costs, but these issues remain largely unresolved.

10 ACTION PLAN

10.1 Resource Acquisition

The only near term (the next 5 years) resource additions indicated in the preferred plan are wind resources. We will continue to explore opportunities to acquire additional wind resources under power purchase agreements and through ownership. Since there is no assurance that the federal Production Tax Credit will be extended indefinitely, there is an incentive to acquire wind resources ahead of our needs.

We expect to need additional natural gas fired generation around 2017. The lead times for such resources are relatively short so no commitment decision is necessary at this time, although early work to develop options is appropriate. The specific timing and types of these additions (whether simple cycle combustion turbines, combined cycle units, or some combination thereof) will depend on market conditions, fuel costs, and the pace of demand and energy growth.

We expect to need additional low/no carbon baseload resources around 2020. There is enough uncertainty about the relative costs and technological availability of resources such as nuclear and advanced coal with carbon capture that there is no clear choice at this time. Since any of these alternatives involve long lead times and significant challenges, early work to develop options is appropriate.

GRE has made conservation its “first fuel” and is committed to making significant strides in minimizing the need for future resources through conservation and efficiency. We have assumed in this resource plan that we will meet the Minnesota 1.5% Energy Conservation Policy Goal. If that goal is not met, then additional resources will be needed.

10.2 Schedule of Key Activities Including Construction and Regulatory Filings

No construction or regulatory filings are contemplated within the next five years unless needed for a GRE-owned wind resource or for advanced development of a peaking or combined cycle resource.

This does not include transmission projects, which are addressed in the reports described in Section 9.3

10.3 Commitment to Update the Commission

GRE will provide the Commission with timely notice of significant changes or deviations from the information presented in this plan.

10.4 Great River Energy's Resource Plan is in the Public Interest

GRE is committed to providing our members with reliable energy at competitive rates and to do so in harmony with a sustainable environment. We have kept that commitment in developing this resource plan by:

- making conservation and energy efficiency our “first fuel” in helping consumers make the most of the energy they use and thereby reduce our need for new supply-side resources;
- working to improve the efficiency of our existing resources;
- continuing to meet much of our future energy requirements with renewable resources;
- evaluating a set of indicative future resource options using capacity expansion modeling under multiple scenarios that included, among other things, a wide range of possible future CO₂ costs; and
- developing a plan that maintains flexibility to adjust for new information and changing circumstances.

The ways in which this resource plan addresses the factors that the Commission must consider in reviewing it are shown in Figure 10-1 below.

Although preparing this plan involved extensive analytics, we focused on making the plan more informative than definitive. Unlike other proceedings, such as Certificates of Need, that require black or white decisions, in a resource plan proceeding we have an opportunity to recognize the many shades of gray associated with how we should meet future electricity needs. We feel that this approach is appropriate in this time of great uncertainty about many of the key parameters that affect those choices.

We respectfully request that the Commission accept this plan as being in the public interest.

Figure 10-1 Commission Review of Resource Plans - Factors to Consider (Minn. Rule 7843.0500 Subp. 3)

Factor	GRE's Plan
<p>A.</p> <p>Maintain or improve the adequacy and reliability of utility service.</p>	<ul style="list-style-type: none"> • GRE uses a 90% probability forecast for long-term capacity planning. • GRE's plan provides for adequate capacity to meet its peak demand requirements over the planning period, including reserve requirements. • GRE is transitioning from a traditional reserve sharing pool to MISO's Resource Adequacy Requirement. GRE, on its own and through MISO and MAPP, is subject to the reliability compliance requirements of NERC and the Midwest Reliability Organization. • GRE has ongoing access to market resources in addition to the self-sufficient resources in the plan. • GRE regularly reviews its near-term capacity situation and makes transactions and plan adjustments accordingly. • Peaking capacity can be added in relatively short timeframes if plans need to change. GRE has extensive experience in procuring, constructing, and operating peaking facilities. • GRE's Transmission Division is actively engaged with other utilities and stakeholders in planning and implementing transmission upgrades and additions needed for reliable and economic operation of the electric system.
<p>B.</p> <p>Keep customers' bills and utility rates as low as practicable, given regulatory and other constraints.</p>	<ul style="list-style-type: none"> • GRE has made conservation and energy efficiency a strategic imperative to help consumers make the most of the energy they use and to minimize the need for new supply resources need. GRE, in concert with our members, will strive to meet the Minnesota 1.5% Energy Conservation Policy Goal. • GRE uses a capacity expansion optimization model to guide the development of resource plans. • GRE has considered a range of scenarios to identify plans that are robust in the face of major uncertainties. • GRE has improved the utilization of its existing assets through efficiency improvements and commercialization of waste heat and other byproducts of generating electricity. • GRE actively participates in MISO's energy markets and bilateral transactions to minimize overall costs. • GRE has determined that CO₂ costs can significantly impact rates. Until CO₂ policies are firmly in place, GRE intends to pursue future baseload needs with low or no CO₂ resources to potentially mitigate rate impacts.

<p>C.</p> <p>Minimize adverse socioeconomic effects and adverse effects upon the environment.</p>	<ul style="list-style-type: none"> • GRE has made conservation and energy efficiency a strategic imperative to help consumers make the most of the energy they use and to minimize the need for new supply resources need. GRE, in concert with our members, will strive to meet the Minnesota 1.5% Energy Conservation Policy Goal. • GRE has been adding wind and other renewable resources to its resource mix ahead of the Renewable Energy Objective/Standard and expects to continue doing so. • GRE has considered a wide range of CO₂ costs in developing its plans and intends to meet future baseload needs with resources that have low or no CO₂ emissions. • GRE has improved utilization of its existing assets and reduced direct and indirect emissions through efficiency improvements, combined heat and power projects, and commercialization of byproducts of generating electricity. • In 2007 GRE became a founding reporter to the Climate Registry • GRE is striving for ISO 14001 environmental management certification of all generating assets
<p>D.</p> <p>Enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations.</p>	<ul style="list-style-type: none"> • GRE has considered a range of scenarios to identify plans that are robust in the face of major uncertainties. • GRE has ongoing access to market resources in addition to the self-sufficient resources in the plan. • GRE regularly reviews its near-term capacity situation and makes transactions and plan adjustments accordingly. • Peaking capacity can be added in relatively short timeframes if plans need to change. GRE has extensive experience in procuring, constructing, and operating peaking facilities. • GRE is moving toward a more-diverse resource portfolio that includes renewables, gas, hydro, coal, nuclear, and other resources of various sizes, locations, technology types, and terms. • GRE is proactively doing front-end work on numerous resource alternatives to choose from as the energy landscape evolves. • GRE staff participate in organizations such as the Electric Power Research Institute, the American Wind Energy Association, the Midwest ISO, and many, many others to monitor and anticipate developments that may affect our business.
<p>E.</p> <p>Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.</p>	<ul style="list-style-type: none"> • See responses to D above.

11 COMPLIANCE

11.1 Orders

Figure 11-1 Docket No. ET-2/RP-05-1100 (In the Matter of Great River Energy's 2005 Integrated Resource Plan), *Order Neither Accepting Nor Rejecting for Resource Planning Purposes, Finding Compliance with Renewable Energy Objectives Statute, and Setting Filing Requirements*, issued August 4, 2006.

Point	Renewable Energy Objectives	Compliance Action
1	The Commission hereby finds GRE in compliance with the renewable energy objectives (REO) statute in 2005 and 2006; the Commission will continue to monitor future compliance through compliance filings, updates and future resource filings.	Compliance with the revised REO and Renewable Energy Standard requirements of Minn. Stat. §216B.1691 (2007) is addressed in Section 5.3.
2	GRE shall apply the Vintage Allocation method and the Fixed Allocation Factor ... in gauging its compliance with the renewable energy objectives statute	GRE uses the recommended methods in allocating renewable energy to its MN and WI loads
3	On or before October 1, 2006, GRE shall file a report and update showing its compliance with the renewable energy objectives statute. This report shall include any information sought by the Department of Commerce for its January 2007 report to the Minnesota Legislature.	Completed
Point	Integrated Resource Plan	Compliance Action
4	The Commission cannot accept or reject GRE's proposed integrated resource plan. The resource plan falls short of full acceptability because of missing information and analytical deficiencies.	GRE has carefully considered and adopted where practicable the guidance offered by the Commission in this Order.
5	GRE's resource plan filing is useful for resource planning purposes and will maintain reliability over at least the next several years in the Cooperative's system. The Commission makes no finding with respect to the acceptability or need for future energy facilities.	No action needed by GRE.
6	The Commission accepts GRE's commitment to adopt the following actions: a. To include a capacity expansion model as part of its modeling process; b. To analyze whether wind generation in excess of that required under the renewable energy objectives might be a cost-effective alternative; and c. To attempt to improve its analytical process for demand side management (DSM) and for its 50 percent and 75 percent conservation/renewable scenarios (e.g., by separating existing DSM from new DSM	<ul style="list-style-type: none"> a. This filing reflects use of a capacity expansion model. See Section 8.2. b. In most scenarios, GRE used RES compliance as a <u>floor</u>, allowing the CEM to choose more wind if economical. See Section 8.3. c. The filing and GRE's CIP filing include estimates of existing DSM. The scenarios analyzed encompass the 50/75% DSM/renewable scenarios, which were not analyzed separately. See Section 8.3.
7	The Commission encourages GRE, when preparing future resource plans, to adopt the following: a. Include wind as a generic resource that the capacity-expansion model can choose, and also include a capacity value in the wind input assumptions;	<ul style="list-style-type: none"> a. Wind is included as a generic resource which the capacity expansion model can choose. See Section 7.2. Wind resources have been credited with a capacity value of 12% of nameplate. See

	<p>b. Refrain from including any resources not yet procured (e.g., the Big Stone II power plant in the current filing) in all of the resource planning scenarios;</p> <p>c. Include in its future assessments of DSM resources an analysis of the cost effectiveness of varying amounts of DSM (i.e., various additional amounts above the statutory minimum amounts.)</p> <p>d. Include consideration of DSM in its 50 percent and 75 percent conservation/renewable scenarios;</p> <p>e. Work with its member, cooperatives to develop DSM projects, and clearly communicate to those members the benefits of DSM (e.g., mitigation of future rate increases).</p>	<p>Section 7.2.</p> <p>b. Only generic future resources are included in the scenarios studied. See Section 7.2.</p> <p>c. Meeting the 1.5% Energy Conservation Policy Goal of Minn. Stat. §216B.2401 is an assumption in the scenarios studied except those designed to measure the effects of greater or lesser levels of load. See Section 8.3.</p> <p>d. Ditto.</p> <p>e. Conservation is now our “First Fuel” in GRE’s strategic imperatives. GRE has reorganized and increased conservation budgets to reflect the importance of conservation. See Section 4.1, 7.1, 10.1.</p>
8	<p>The Commission encourages GRE, when preparing future resource plans, to consider and adopt the following actions, and if it determines not to implement any of them, to provide an explanation in GRE's next resource plan filing:</p> <p>a. Forecast system level energy and demand requirements using an econometric model;</p> <p>b. Reconcile the historical data to explain what appears to be negative line losses;</p> <p>c. Incorporate a weather variable into the econometric model;</p> <p>d. File an annual forecast with the Department; and</p> <p>e. In at least its contingency plan modeling, use a final CO₂ value of \$8 per ton as an annual levelized cost in 2004 with higher values thereafter, as was done in California.</p>	<p>a. GRE used an econometric forecast of system level energy and demand. See Section 3 and Appendix A.</p> <p>b. See Appendix A.6.</p> <p>c. See Appendix A.</p> <p>d. See Appendix F.</p> <p>e. GRE used a wide range of CO₂ values, including values greatly exceeding \$8/ton. See Section 8.3 and Appendix C.</p>
9	<p>GRE shall include the following informational items in its next resource plan filing:</p> <p>a. A review of the current price and price trends of allowances and/or credits for SO₂, NO_x and CO₂, as well as a comparison of the cost of implementing control technologies for these emissions;</p> <p>b. An update on the development of future pending and potential environmental regulations that may impact electric utility operations, based upon its monitoring of those issues;</p> <p>c. Demand and energy goals for its demand side management projects, and a report on actual performance in the projects by its member cooperatives (e.g. expenditures, generator kilowatt-hour savings, and generator kilowatt savings); and/or</p> <p>d. Annual generation from existing and planned wind facilities and the reasons for significant changes in output.</p>	<p>a. GRE used forecasts provided by Ventyx for SO₂ and NO_x and studied a wide range of CO₂ costs. See Section 8.3.</p> <p>b. See Section 5</p> <p>c. See Section 4.1, 7.1, and GRE’s 2008 CIP filing in Docket No. ET2/PR-08-254</p> <p>d. See Section 5.3</p>

10	<p>GRE shall seek to cooperate with other utilities including Xcel to develop information and be prepared to participate in a Commission-sponsored technical issues workshop on the following subjects:</p> <p>a. Wind energy storage research and development;</p> <p>b. The cost of implementing various mitigation strategies and control technologies for the costs of NO_x, SO₂ and CO₂, including cost estimates, the technology needed to capture and ship CO₂ from an integrated gasification combined cycle plant to another appropriate location, and the cost of the various regulatory strategies under consideration for reduction of those emissions;</p> <p>c. With respect to distributed generation of heat and power, what the components of a more comprehensive distributed generation strategy might entail: a technical evaluation of the opportunities, technical potential and economics of distributed generation with the GRE system, including:</p> <ul style="list-style-type: none"> - evaluation of large customer sites to determine appropriateness and willingness to consider distributed, generation including possible combined heat and power initiatives with the ethanol industry and other industries; - determination of total technical distributed generation potential; - calculations of grid benefits of distributed generation; and - economic screening to determine the total economic impact of distributed generation, under either utility ownership or customer ownership of distributed generation. 	<p>GRE stands ready to cooperate in developing information and participating in any such technical workshops on these topics.</p>
Point	Next Resource Plan	Compliance Action
11	GRE shall file its next resource plan on or before November 1, 2007	Delayed to July 1, 2008 pursuant to <i>Order Granting Filing Date Extension, With Requirements</i> , issued October 31, 2007.

Figure 11-2 Docket No. ET-2/RP-05-1100 (In the Matter of Great River Energy's 2005 Integrated Resource Plan), *Order Granting Filing Date Extensions, With Requirements*, issued October 31, 2007.

Point	Renewable Energy Objectives	Compliance Action
1	The Commission hereby grants the request of Great River Energy *** for an extension to file the Cooperative's Integrated Resource Plan *** no later than July 1, 2008 with the following two qualifications.	Compliance with the revised REO and Renewable Energy Standard requirements of Minn. Stat. §216B.1691 (2007) is addressed in Section 5.3.
2	GRE shall answer questions about the Cooperative's need for additional resources as requested by the Department in a timely manner to allow the Department to file written comments in the Elk River Certificate of Need Docket, ET-2/CN-07-678.	Completed.
3	<p>In its next IRP, GRE shall</p> <p>a) address any newly legislated CO₂ management and reduction goals and policies in Minnesota statute;</p> <p>b) consider opportunities for the installation of distributed generation as required under Minn. Stat. §216B.2426;</p>	<p>a. GRE analyzed a wide range of CO₂ values, including the range established in Docket E-999/CI-07-1199, <i>Order Establishing Estimate of Future Carbon Dioxide Regulation Costs</i>, issued December 21, 2007, reaffirmed February 20, 2008. See Section 8.3.</p> <p>b. GRE Transmission has been a key participant in the G & T Optimization Study</p>

	<p>c) provide clear, consistent, and transparent information about the natural gas prices and forecasts used in its resource plan, making as much of that information public as possible;</p> <p>d) provide the results of model runs using base case, high and low gas price assumptions, and be as clear as possible about the sensitivity of the resource outcomes to the gas price assumptions;</p> <p>e) clearly discuss why GRE believes that its models use reasonable assumptions (in light of, for example actual annual aggregate volume of natural gas consumed for power generation for GRE's owned and contracted natural gas plants and current natural gas storage and transportation capacity in Minnesota) and produce logical results.</p>	<p>and the Distributed Renewable Generation Study referred to in Section 9. GRE's members have DG tariffs pursuant to Minn. Stat. §216B.1611</p> <p>c. GRE used fuel forecasts purchased from Ventyx. These forecasts are trade secret but may be obtainable from Ventyx.</p> <p>d. See Section 8 and Appendix C.</p> <p>e. See Section 8 and Appendix C.</p>
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Figure 11-3 Docket E-999/CI-07-1199, Order Establishing Estimate of Future Carbon Dioxide Regulation Costs, issued December 21, 2007, reaffirmed February 20, 2008.

	Requirement	Compliance Action
	<p>The Commission estimates that CO₂ regulation of electricity generation will cost between \$4/ton and \$30/ton for CO₂ emitted in 2012 and thereafter.</p> <p>Electric utilities shall apply these estimates in all proceedings to acquire electricity generation resources to serve needs in Minnesota.</p> <p>In estimating costs associated with CO₂ emissions for the purpose of analyzing electricity generation resources, a utility need not apply CO₂ externality costs derived pursuant to § 216B.2422, subdivision 3, to CO₂ emitted in any year to which the utility applies the CO₂ regulation costs derived pursuant to Minnesota Statutes § 216H.06.</p>	<p>GRE used CO₂ costs in this range as well as above and below. See Section 8.3.</p>

11.2 Minnesota Statutes

Minn. Stat. §§	Requirement	See
216B.2422 Subd. 2	<u>Resource plan filing and approval.</u> *** As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources.	The 50/75% conservation/renewable scenarios are encompassed in the scenarios that were analyzed. Section 8 and Appendix C.
216B.2422 Subd. 2a	<u>Historical data and advance forecast.</u> Each utility required to file a resource plan under this section shall include in the filing all applicable annual information required by section 216C.17, subdivision 2, and the rules adopted under that section. To the extent that a utility complies with this subdivision, it is not required to file annual advance forecasts with the department under section 216C.17, subdivision 2.	Appendix F.
216B.2422 Subd. 3	<u>Environmental costs.</u> (a) The commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.	Section 8.3.
216B.2422 Subd. 4	<u>Preference for renewable energy facility.</u> The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest.	Sections 8 and 10.
216B.2422 Subd. 6	<u>Consolidation of resource planning and certificate of need.</u> A utility shall indicate in its resource plan whether it intends to site or construct a large energy facility. If the utility's resource plan includes a proposed large energy facility and construction of that facility is likely to begin before the utility files its next resource plan, the commission shall conduct the resource plan proceeding consistent with the requirements of section 216B.243 with respect to the proposed facility. If the commission approves the proposed facility in the resource plan, a separate certificate of need proceeding is not required.	Section 10.2.

Minn. Stat. §§	Requirement	See
216C.17 Subd. 2 & 3	<p>Subd. 2. <u>Forecasts.</u> Except as provided in subdivision 3, in addition to supplying the current statistical and short-range forecasting information the commissioner requires, each utility, coal supplier, petroleum supplier and large energy facility in the state shall prepare and transmit to the commissioner by July 1 of each year, a report specifying in five-, ten-, and 15-year forecasts the projected demand for energy within their respective service areas and the facilities necessary to meet the demand. The report shall be in a form specified by the commissioner and contain all information deemed relevant by the commissioner.</p> <p>Subd. 3. <u>Duplication.</u> *** Electric utilities submitting advance forecasts as part of an integrated resource plan filed pursuant to section 216B.2422 and Public Utilities Commission rules are excluded from the annual reporting requirement in subdivision 2.</p>	Appendix F.
216B.1691 Subd. 3	<p><u>Renewable Energy Objectives: Utility plans filed with commission.</u> (a) Each electric utility shall report on its plans, activities, and progress with regard to the objectives and standards of this section in its filings under section 216B.2422 or in a separate report submitted to the commission every two years, whichever is more frequent, demonstrating to the commission the utility's effort to comply with this section. In its resource plan or a separate report, each electric utility shall provide a description of:</p> <ul style="list-style-type: none"> (1) the status of the utility's renewable energy mix relative to the objective and standards; (2) efforts taken to meet the objective and standards; (3) any obstacles encountered or anticipated in meeting the objective or standards; and (4) potential solutions to the obstacles. 	Section 5.3.
216B.1612 Subd. 5(b)	<p><u>Priority for Community-Based Energy Development projects.</u> Each utility shall include in its resource plan submitted under section 216B.2422 a description of its efforts to purchase energy from C-BED projects, including a list of the projects under contract and the amount of C-BED energy purchased.</p>	Section 5.3.5.

11.3 Minnesota Rules

Part	Requirement	See
7843.0400	<u>Contents of Resource Plan Filings</u>	
Subp. 1	<p><u>Advance forecasts.</u> A utility shall include in the filing identified in subpart 2 its most recent annual submission to the Minnesota Department of Commerce and the Minnesota Environmental Quality Board under Minnesota Statutes, sections 216B.2422, subdivision 2a, and 216C.17, and parts 7610.0100 to 7610.0600.</p>	Appendix F.

Subp. 2	<p><u>Resource plan.</u> A utility shall file a proposed plan for meeting the service needs of its customers over the forecast period. The plan must show the resource options the utility believes it might use to meet those needs. The plan must also specify how the implementation and use of those resource options would vary with changes in supply and demand circumstances. The utility is only required to identify a resource option generically, unless a commitment to a specific resource exists at the time of the filing. The utility shall also discuss plans to reduce existing resources through sales, leases, deratings, or retirements.</p> <p>“Derating” means a temporary or permanent reduction in the expected power output of a generating facility.</p>	Sections 8 and 10.
Subp. 3	<p><u>Supporting information.</u> A utility shall include in its resource plan filing information supporting selection of the proposed resource plan.</p>	
Subp. 3(A)	<p>When a utility's existing resources are inadequate to meet the projected level of service needs, the supporting information must contain a complete list of resource options considered for addition to the existing resources. At a minimum, the list must include new generating facilities of various types and sizes and with various fuel types, cogeneration, new transmission facilities of various types and sizes, upgrading of existing generation and transmission equipment, life extensions of existing generation and transmission equipment, load-control equipment, utility-sponsored conservation programs, purchases from non-utilities, and purchases from other utilities. The utility may seek additional input from the commission regarding the resource options to be included in the list. For a resource option that could meet a significant part of the need identified by the forecast, the supporting information must include a general evaluation of the option, including its availability, reliability, cost, socioeconomic effects, and environmental effects.</p>	Section 7, Appendix D, and Appendix E.
Subp. 3(B)	<p>The supporting information must include descriptions of the overall process and of the analytical techniques used by the utility to create its proposed resource plan from the available options.</p>	Sections 2, 8, and 10.
Subp. 3(C)	<p>The supporting information must include an action plan, a description of the activities the utility intends to undertake to develop or obtain non-current resources identified in its proposed plan. The action plan must cover a five-year period beginning with the filing date. The action plan must include a schedule of key activities, including construction and regulatory filings.</p>	Section 10.
Subp. 3(D)	<p>For the proposed resource plan as a whole, the supporting information must include a narrative and quantitative discussion of why the plan would be in the public interest, considering the factors listed in part 7843.0500, subpart 3.</p>	Section 10.
Subp. 4	<p><u>Non-technical summary.</u> A utility shall include in its resource plan filing a non-technical summary, not exceeding 25 pages in length and describing the utility's resource needs, the resource plan created by the utility to meet those needs, the process and analytical techniques used to create the plan, activities required over the next five years to implement the plan, and the likely effect of plan implementation on electric rates and bills.</p>	Executive Summary.

Subp. 5	<u>Combined and common filings.</u> Utilities may combine their individual filings into a single larger filing, as long as the action does not lead to a loss of information. Information common to two or more of the utilities need only be submitted once, as long as the filing clearly shows the utilities to which the information applies.	Not applicable.
7610.0300	<u>Extended Forecast.</u> The following utilities must file the information required by parts 7610.0100 to 7610.0700: Northern States Power Company, Minnesota Power, Otter Tail Power Company, Interstate Power Company, Minnkota Power Cooperative, Cooperative Power Association, United Power Association and Dairyland Power Cooperative, and the Southern Minnesota Municipal Power Agency. Data that is compiled within the same calendar year for either an extended forecast or a certificate of need application may be substituted interchangeably to satisfy those portions of both sets of rules that have identical data requirements. For these cases, references to the material substituted and a copy of the appropriate reference material must be submitted to meet the reporting requirements.	Appendix F.