Chapter 4. Modeling and Plan Description

Strategist Resource Planning Model

This chapter introduces the Strategist Resource Planning software, evaluates the resources available for capacity expansion, and presents the details of the Company's proposed plan. Xcel Energy has used the "Strategist" model in our Resource Plans since 2000. Strategist is used to estimate the cost of various resource expansion plans, to evaluate specific capacity alternatives and measure the potential risks of new environmental legislation and other policy scenarios.

The Strategist Model is also used to test the reasonableness and the robustness of this Resource Plan. We work to characterize our current system and to develop assumptions that accurately reflect our expert opinion of likely future conditions. Strategist, in turn, helps with the analysis of the myriad of options and "what if" scenarios that must be a part of a robust planning regime.

The model consists of four primary components.

- *Load Module* that contains Xcel Energy's load forecast, load management, and conservation programs. This module produces long-range estimates of the Company's net energy requirements and peak capacity requirement.
- *Generation Module* that contains the operating costs and performance characteristics for our thermal units, renewable resources, and transactions. This module uses an hourly dispatch simulation to estimate how demand will be met and what the associated costs and emissions will be.
- *Capital Project Module* that estimates the revenue requirement for capital projects such as new generating resources. This module keeps track of rate base, depreciation, taxes, and rate of return for existing and future capital projects.
- *Expansion Planning Module* that uses a dynamic programming algorithm to derive the least cost expansion plan under the assumptions used. This

module calculates the customer and societal costs for thousands of different resource combinations to arrive at the least cost plan.

For each expansion plan, Strategist calculates fuel consumption, fuel costs, O&M costs, emission rates, capital costs, and total revenue requirement. The total system costs are reported as the net present value of revenue requirements or "PVRR." This value is the sum of all operating, depreciation, return on rate base, and tax costs, less any revenues from sales discounted back to 2010 using the Company's most recently authorized weighted after tax cost of capital
of 7.47%.

By using Strategist, we can explore how our plan will meet customer needs under a variety of conditions at a reasonable cost. Strategist tests our plan under a number of possible futures and allows us to select a robust plan that meets our current and expected future legal and regulatory requirements.

Baseline Assumptions

Although the planning period in this report covers 2011-2025, Strategist analysis covers 2011-2049 and our reported PVRR values correspond to this time period. The longer time interval allows us to better estimate the costs and benefits of the long-lived resources proposed in this plan.

Important base assumptions in our analysis include:

Forecast

- We plan to meet the 50% probability level of forecasted peak demand, and the 50% probability level of forecasted energy requirements. The forecast has been offset by DSM savings levels of 1.3% and 1.5% energy savings to evaluate each of these levels.

Existing Fleet

- Cost and performance assumptions are consistent with historical data.

- Costs are escalated based on corporate estimates of expected inflation rates.
- Continued operation of our Sherco and King generating stations throughout the study period.
- Retirement of our Prairie Island nuclear generating station at the end of its proposed license renewal (2033, 2034), and retirement of Monticello at the end of its current license (2030), and for the purposes of this planning document and analyses, replacement with new nuclear generation.
- Retirement of other facilities at their current expected end of life if within the Resource Planning period, unless we have specifically included costs of life extension.[1]
- Continuation of our existing power purchase contracts until their contractual termination dates.
- Continued operation of Xcel Energy's hydroelectric resources based on historical performance.

Renewable Energy

- Addition of up to 1150 MW of wind through 2020 beyond the amounts already approved by regulators, in order to meet our renewable energy targets.
- Accreditation of wind resources based on MISO planning reserve credit allocation (currently 8%).
- Extension of the Federal Production Tax Credit through 2014.
- Additional ancillary service charges for wind based on the 2006 Minnesota Wind Integration Study.

Emissions

- Emission rates for existing and planned resources consistent with historical and expected performance.
- Cap and trade permit systems for SO_2, and NOx.
- A planning number of $ 17 per ton CO_2 starting in 2012 and escalating at 1.9% per annum

[1] The one exception to this assumption is with regard to our Sherco 1 and 2 units. These facilities reach the end of their book lives in 2023. However, we are initiating a life extension study for these units, and are assuming, for the purposes of this Resource Plan analysis, that they continue to operate beyond 2023.

- We did not incorporate the Commission's externality values for specified emissions as a base assumption, but included those high and low externality values as sensitivities.

Strategist uses generically defined resources to meet future demand when existing resources fall short. The Company used the following generic resources as model inputs for this Resource Plan:

- 195 MW gas-fired Combustion Turbine peaking unit (CT), available to the model for selection for the summer peak of 2015
- 730 MW gas-fired Combined Cycle intermediate unit (CC), available for selection for the summer peak of 2017
- 500 MW Super Critical Pulverized Coal base load unit, available for selection by 2020
- 100 MW Wind project (Wind).

Cost and performance data for these units are based on a consultant's estimates and internal company data. Availability dates are selected based on our estimates of the lead time needed for regulatory approvals, financing, permitting and construction. Strategist does not manage the selection of wind projects well, so we hard code wind projects into the model to be able to see their impacts on PVRRs, emissions, rates, etc. A complete list of the Strategist assumptions we used is provided in Appendix B at page 5.

Proposed Plan

We developed our proposed plan following through on key items identified in the previous Resource Plan. Our proposed plan includes the following major components:

- Completing the uprate projects for Prairie Island and Monticello
- Extending our relationship with Manitoba Hydro through 2025
- Repowering our Black Dog generating plant with natural gas and increasing its generating capacity by more than 400 MW

- Adding 1365 megawatts of peaking capacity through 2025
- Integrating an additional 250 MW of wind by 2012 with flexible timing of renewable additions beyond that date to ensure the best value to our ratepayers and
- Building our DSM programs to achieve savings of 1.3% of annual sales, increasing to 1.5% over the next several years.

We have petitioned the Commission for approval of the extension of the Manitoba Hydro agreements, in MPUC Docket No. E002/M-10-633. In the analysis and development of this Resource Plan, we assume the extension of those agreements is approved. For the sake of administrative efficiency, we respectfully request that the evaluation of our Manitoba Hydro proposal and alternatives to that proposal be considered within the Manitoba Hydro proceeding, and that issues and questions related to that proposal in this Resource Plan be directed to that Docket. We will incorporate the results of that proceeding into our Resource Plan.

Table 4.1 summarizes the expansion plan for the proposed plan. Figures 4.1 and 4.2 show the Plan's energy mix and C02 emissions, respectively.

Table 4.1
Proposed Plan Expansion Plan

Year	Planned Additions	Combined Cycle	Combustion Turbine	Supercritical Pulv. Coal	Wind
		Generic Additions			
2011	Merricourt 150 MW				
2012	Monty EPU 71 MW				250 MW
2013					100 MW
2014	PI Unit 1 EPU 82 MW				100 MW
2015	MH 725 MW extension PI Unit 2 EPU 82 MW				100 MW
2016		Black Dog Combined Cycle 680 MW			100 MW
2017					100 MW
2018					100 MW
2019					100 MW
2020			390 MW		200 MW
2021	MH 125 MW				
2022			195 MW		200 MW
2023					
2024			195 MW		200 MW
2025		730 MW	585 MW		200 MW

Figure 4.1
Proposed Plan 2015 Energy Mix

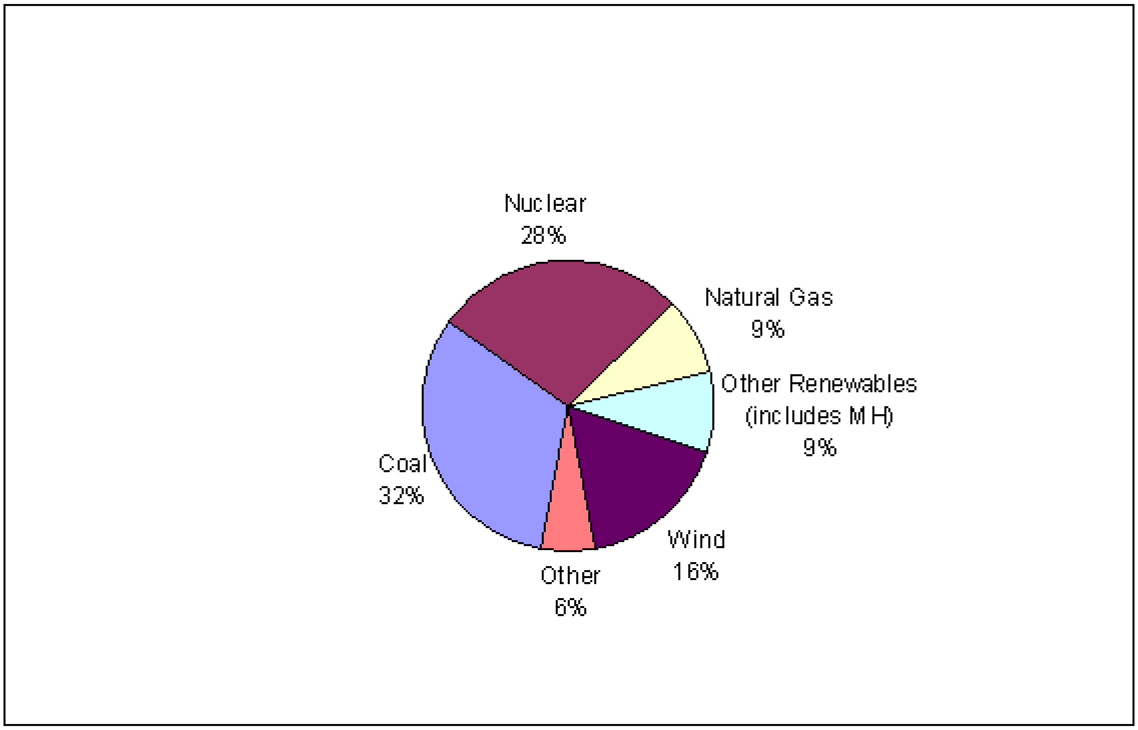
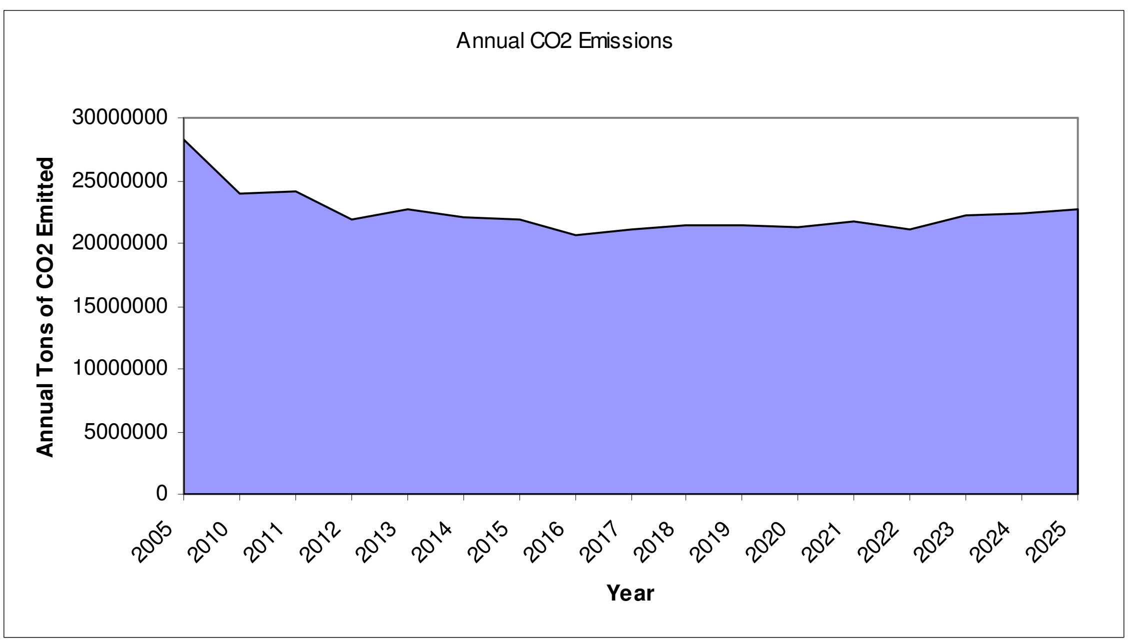


Figure 4.2
Proposed Plan CO2 Emissions



The wind additions of the proposed plan are "hard coded" into Strategist to ensure that the model selects sufficient wind resources to comply with our renewable energy obligations. Our proposed plan includes the full complement of wind needed to satisfy our RES requirements primarily from annual generation in 2020 and installs it on a steady schedule of approximately 100 MW/year. However, as discussed in the Renewable Energy chapter, we have flexibility with respect to the amount and timing of wind generation that needs to be installed over the planning period and depending upon the costs and other factors, we could use RECs to defer some of our obligations. Reducing the amount of wind in our proposed plan would have minimal impact on the type and timing of other resources in the plan.

In addition to an overall requirement to have 30% of our retail sales come from renewable resources, the Minnesota Renewable Energy Standard (RES) requires us to achieve a wind penetration of 25% of our retail energy sales by 2020, which is the highest penetration of wind energy required in the country, and at the limits of what was studied in the Minnesota Wind Integration Study. Because we are still unsure about the operational impacts of this amount of wind on our system, we did not test levels of wind in the model that are higher than the RES requirements.

Description and analysis of key parts of the proposed plan are included in their respective chapters:

- Our Wind Expansion Plan and the Manitoba Hydro agreements are discussed in the Renewables Energy chapter.
- Repowering of the remaining coal units at our Black Dog facility is discussed in the Thermal Generation chapter
- Our DSM program and goals are discussed in the DSM and Load Management chapter

Sensitivity Analysis

To determine how changes in our assumptions impact the costs or characteristics of different Resource Plans, we examine our plans under a number of scenarios. If a plan is extremely sensitive to changes in assumptions, it is not a robust course of action for the Company to pursue. Instead, we conceivably could propose an expansion plan that is less sensitive to assumption changes, but slightly more costly than the least-cost scenario. For this Resource Plan, we tested the following scenarios.

- *Load.* The base forecast (unadjusted for DSM) is the 50% probability level of forecasted peak demand, and the 50% probability level of forecasted energy requirements. To test the sensitivity of our plans to changes in our forecast, we used the 80% probability level of forecasted peak and energy requirements as the "high load" sensitivity and the 20% probability level as the "low load" sensitivity. We also used the "high load" sensitivity as a proxy for resources that may be needed if we experience a robust economic recovery.
- *Natural Gas costs.* The cost of natural gas was adjusted up and down by 20% from the base natural gas cost forecast.
- *Externalities.* The Commission's low and high externality values were added to test the societal impacts of each expansion plan. However the Company's CO_2 planning values were used in place of the Commission's CO_2 externality values.
- *CO_2 Values.* CO_2 planning values were varied down to a low of $9/ton and up to $34/ton, both beginning in 2012. Due to the uncertainty currently surrounding the timing and extent of carbon regulation, we also tested a CO2 planning value of $17 per ton beginning in 2017 ("late carbon", as well as a sensitivity of using no CO2 planning value at all.
- *PTC.* In addition to the base assumption that the PTC would be extended once more, through 2014, we also wanted to see how the Plan reacted to PTC expirations of 2012 and 2020.

Strategist does have some limitations. Although it uses hourly information, it is not a chronological model. Hourly patterns for energy demand are rearranged into load duration curves and thermal dispatch simulations are based on these curves. This allows us to quickly simulate several years of operation on our system, but the model loses the ability to capture some operational detail, such as the ramp rates on our generating units. This makes it difficult for us to use the model to evaluate the benefits of quick start combustion turbines relative to our generic combustion turbines. Also, Strategist uses a simplified approach to modeling load and wind patterns. Instead of using an hourly pattern that covers every hour in an entire month, we model a typical week in that month that the model repeats several times to simulate the entire month.

Table 4.2 shows the PVRRs of the proposed plan under the base assumptions and various sensitivity tests.

Table 4.2
PVRRs of Proposed Plan and Sensitivities

	PVRR ($000s)	Diff from Base ($000s)
Base	$90,702,859	
High Gas	$92,184,890	$1,482,031
Low Gas	$89,192,022	-$1,510,837
High CO2	$96,328,301	$5,625,443
Low CO2	$88,058,510	-$2,644,349
Late CO2	$88,445,801	-$2,257,057
No CO2	$85,087,884	-$5,614,975
High Load	$96,466,131	$5,763,272
Low Load	$86,582,937	-$4,119,921

Under the "low load" sensitivity, Strategist adds no generic resources until 2025, adding a combustion turbine (CT) and a combined cycle (CC) facility at that time. Under the "high load" sensitivity, Strategist suggests that we would need an additional 585 MW of CTs in 2015, and additional CTs in 2018 and 2019. As noted above, this high load sensitivity simulates the impact of a robust economic recovery on our system. The additional generation selected by Strategist under this sensitivity points out the need for a specific, implementable contingency generation plan, which we discuss in Chapter 6.

Minnesota Statute, section 216B.2422, subdivision 3, requires that we consider the environmental cost values for various emissions established by the MPUC. Table 4.3 shows how incorporation of those values affects the PVRR for the proposed plan.

Table 4.3
PVRRs of Plan w/ MPUC Externalities

	PVRR ($000s)	$ Diff from Base
Base	$90,702,859	
High Externalities	$91,049,294	$346,436
Low Externalities	$90,832,316	$129,457

Scenario Analysis

To address issues that have been raised since we filed our 2007 Resource Plan, we developed two additional set of scenarios – the "North Dakota/South Dakota" ("ND/SD") scenario and the No New Wind Scenario. The ND/SD scenario has been developed pursuant to settlements with North Dakota and South Dakota in our most recent general rate cases in those jurisdictions. The No New Wind scenario has been developed based on our commitment in the Minnesota Commission's Docket E-999/CI-03-869 to file information on the costs and rate impacts to our system if we were not required to meet the Minnesota RES. Although neither of the studied scenarios would result in compliant Resource Plans under Minnesota law, comparing our proposed plan to these alternatives helps to identify the effect of differing approaches to public energy policy.

ND/SD Scenario

Xcel Energy plans and operates a single system that serves both its Minnesota and Wisconsin operating companies and all five jurisdictions therein. The development and operation of the joint system has benefitted all of our customers by allowing us to create a nearly 10,000 MW, diversified system at a lower cost than separately meeting the needs of each state or company.

Over the past several years, individual states have started to develop their own regulatory and environmental policies. These policies include renewable energy standards, the treatment of environmental cost factors, demand-side management policies and conditions placed on the construction of generation and transmission facilities. Given these different policies, our goal has always been to meet our requirements in all jurisdictions at the lowest possible cost to consumers.

Of Xcel Energy's jurisdictions, Minnesota has adopted the most reasonable policies for electric utilities. Along with a 30% Renewable Energy Standard, Minnesota has adopted a range of carbon values for use in Resource Planning and has placed conditions on the continued operation of our nuclear plants. In recent rate proceedings, other jurisdictions have expressed concerns that our compliance with certain Minnesota policies has caused their customers to pay higher rates than they might otherwise. As part of our settlements in recent rate cases with North Dakota and South Dakota, we agreed to develop scenarios in our Resource Plan to examine the differences between our proposed plan, which meets at least minimum requirements in all jurisdictions, and a plan that more closely reflects requirements for their states.

The ND/SD scenario was designed around the environmental and renewable policies in North and South Dakota. Both jurisdictions have similar state policies, so we have developed a single scenario for both states that is designed to meet but not exceed Federal, North Dakota and South Dakota environmental and renewable requirements as they currently exist. This scenario does not, for example, take into account the potential for carbon pricing under a federal cap and trade plan, or a federal renewable energy standard. To model the ND/SD scenario, we made changes to our base assumptions for our proposed plan to remove renewable installations, environmental externality costs, demand-side management programs and planning costs for CO_2 emissions.

Specifically, we made the following changes to the Strategist model to arrive at the ND/SD:

- We eliminated all CO_2 related costs and constraints.
- We allowed Strategist select one or more Supercritical Pulverized Coal Plants (500 MW each), with no carbon capture and sequestration requirement.
- We eliminated all assumptions regarding environmental externality values.
- We limited our wind expansion plan to the amount necessary to meet a 10% renewable energy objective system-wide. Because we already obtain more than 10% of our energy from renewables, this change effectively eliminated all future wind that is not already under contract or specifically committed to be installed in North Dakota from the plan.
- We increased our sales forecast by eliminating the energy savings and respective costs associated with meeting our Minnesota energy conservation requirements.

Table 4.4 shows the expansion plan for the ND/SD scenario.

Table 4.4
ND/SD Scenario Expansion Plan

Year	Planned Additions	Combined Cycle	Combustion Turbine	Supercritical Pulverized Coal	Wind
		Generic Additions			
2011	Merricourt 150 MW				
2012	Monti EPU 71 MW				
2013					
2014	PI Unit 1 EPU 82 MW				
2015	MH 725 MW ext PI Unit 2 EPU 82 MW		390 MW		
2016		BDCC 680 MW			
2017			195 MW		
2018			195 MW		
2019			195 MW		
2020				500 MW	
2021	MH 125 MW				
2022				500 MW	
2023					
2024				500 MW	
2025			585 MW	500 MW	

Table 4.5 shows the relative PVRRs of the proposed plan and the ND/SD scenario.

Table 4.5
PVRR Comparison

PVRR ($000s)	Proposed plan	ND/SD	Difference from Proposed plan
Base	$90,702,859	$88,759,587	-$1,943,272
No CO2	$85,087,884	$88,759,587	$3,671,703
High Gas	$92,184,890	$90,401,014	-$1,783,876
Low Gas	$89,192,022	$87,100,337	-$2,091,685
High Load	$96,466,131	$93,483,053	-$2,983,078
Low Load	$86,582,937	$82,852,314	-$3,730,623

Direct comparison of the base PVRRs between our proposed plan and the ND/SD scenario are somewhat misleading. Although direct evaluation of the base scenarios indicates that our proposed plan has a PVRR that is $1.9 billion higher than this scenario, the proposed plan includes estimates for the cost of carbon that are not levied directly onto our customers in the absence of carbon regulation. Rather, the cost of carbon is used to determine which resources should be selected in the face of a carbon-constrained regulatory scheme. As a result, the true direct cost differences between the plans exist because the evaluation of carbon may cause us to select resources that are a slightly higher cost but less carbon intensive than the least cost resources.

A better indicator of the direct cost comparison between the proposed plan and the ND/SD scenario is shown under the "no carbon" sensitivity. Under this case, we have taken the proposed plan and determined its PVRR without carbon costs. Because the ND/SD scenario already had no carbon cost, its PVRR is the same as the base as demonstrated in line two in the table above. As demonstrated in the table above, when hypothetical costs of carbon are not included in the PVRR of the proposed plan, it is actually $3.7 billion lower than that of the ND/SD scenario.

The largest part of this approximately $3 billion difference is due to the elimination of Minnesota DSM programs from the ND/SD scenario. Our Minnesota Conservation Improvement Program represents a significant investment by Minnesota customers in obtaining cost-effective demand and energy savings that allow us to reduce the amount of resources needed system-wide to serve our customers. As seen in the comparison between the proposed plan and the ND/SD scenario, these programs result in a system that requires fewer resources and a significantly lower PVRR.

This comparison provides a clear example of the synergies that exist in an integrated system such as the one we plan and operate. In some cases, requirements in one state cause average costs to rise across the system, but in other cases requirements can cause average costs to fall. This, combined with economies of scale and diversity of load across our system, allows the integrated system to provide better service and lower costs than stand-alone systems would, even in the face of differing jurisdictional energy policy.

Considering that we will continue to invest in Minnesota DSM programs as required by Minnesota Statute, North Dakota and South Dakota will continue to obtain the large benefits provided by those programs. To isolate the PVRR difference between the proposed plan and the ND/SD scenario based solely on differences in the resources selected in each plan, we added DSM back to the ND/SD scenario and calculated a new expansion plan and PVRR. The ND/SD expansion plan with DSM is shown in Table 4.6.

Table 4.6
ND/SD Expansion Plan with DSM

Year	Planned Additions	Combined Cycle	Combustion Turbine	Supercritical Pulverized Coal	Wind
		Generic Additions			
2011	Merricourt 150 MW				
2012	Monti EPU 71 MW				
2013					
2014	PI Unit 1 EPU 82 MW				
2015	MH 725 MW ext PI Unit 2 EPU 82 MW				
2016		BDCC 680 MW			
2017					
2018					
2019			195 MW		
2020				500 MW	
2021	MH 125 MW				
2022					
2023					
2024				500 MW	
2025			390 MW	500 MW	

The PVRR of the ND/SD scenario with DSM is $84,999,976,000. Compared to the direct costs of the proposed plan at $85,087,884,000, the ND/SD scenario with DSM is $87.9 million dollars lower than our proposed plan over the 39 year model run.

This PVRR difference represents the cost to our customers to make resource choices that mitigate future emissions of carbon and criteria pollutants.

Our analysis of the ND/SD Scenario shows that our proposed plan is a reasonable plan, even when we consider it in light of the different policy approaches that North and South Dakota use. Our proposed plan has a lower PVRR than the ND/SD Scenario, excluding any CO2 planning value assumption, by $3.6 billion. Many of the measures that we undertake to comply with requirements in other jurisdictions, such as our Demand-Side Management programs, are cost-effective in their own right. Other measures, including compliance with higher renewable standards, mitigate certain risks in our plan such as exposure to volatile fuel prices.

To the extent that certain federal environmental regulations such as carbon and mercury are enacted, our proposed plan has fewer emissions of every criteria pollutant and carbon than the ND/SD scenario. While we have not monetized these differences, fewer environmental emissions mean much lower risk of operational and compliance impacts that could result from the environmental regulations expected over the next few years. These federal regulations and their potential impacts on our system are described in the Environment chapter.

Table 4.7
Emissions Comparison
Total Tons Emitted 2010-2049

	Plan	ND/SD	% Diff from Plan
SOx	1,021,188	1,628,119	59.4%
NOx	703,926	1,062,560	50.9%
CO2	969,920,472	1,399,146,160	44.3%
CO	137,292	190,319	38.6%
PM10	106,772	151,953	42.3%
VOCs	20,941	27,517	31.4%
HG	30,272	53,457	76.6%

No New Wind Scenario

Another scenario we created is the "No New Wind" scenario. We identified this scenario in our October 2, 2009 comments in MPUC Docket E-999/CI-03-869 as a means of determining the cost of complying with the Minnesota RES.[1] Developing a baseline scenario that indicates our likely expansion plan if we were to add no wind to our system creates an aggregate look at the cost of complying with the RES that we can build on in future resource plans. If wind additions are cost effective in aggregate, we would expect the PVRR of this scenario to be higher than our proposed plan. In the opposite case, where wind additions are not cost effective, the PVRR of this scenario will be lower than the proposed plan. The difference in annual costs

[1] In those comments, we said "Beginning with our August 2010 Resource Plan filing, Xcel Energy proposes to provide full expansion plans and rate impacts of our plan to comply with the RES as well as an optimized plan that does not take the RES into consideration. To the extent that those plans differ, we will provide an analysis of the difference between the two plans, including the full costs and risks of both options. This will provide a baseline for the Commission to evaluate cumulative rate impacts of meeting the RES over each planning cycle."

between the two scenarios can be converted to rate impacts to calculate how much the RES saves or costs.

To create this scenario, we did not add any wind generation after the additions that we currently have under contract are operational, and held all other components of the proposed plan constant. Table 4.8 shows the expansion plan for the "No New Wind" Scenario.

Table 4.8
No New Wind Scenario Expansion Plan

Year	Planned Additions	Combined Cycle	Combustion Turbine	Supercritical Pulverized Coal	Wind
		Generic Additions			
2011	Merricourt 150 MW				
2012	Monti EPU 71 MW				
2013					
2014	PI Unit 1 EPU 82 MW				
2015	MH 725 MW ext PI Unit 2 EPU 82 MW				
2016		BDCC 680 MW			
2017					
2018					
2019			195 MW		
2020			195 MW		
2021	MH 125 MW				
2022			195 MW		
2023			195 MW		
2024			195 MW		
2025		730 MW	390 MW		

In comparison with the proposed plan, the No New Wind scenario does not add more resources, but does advance a CT from 2020 to 2019, and another CT from 2025 to 2023. A model without wind does not add more capacity than our proposed plan because wind receives a very low capacity credit in MISO (8 percent). However, the lack of new wind generation on the system means that our resources will need to produce additional energy to meet our needs. At certain times, this results in our gas resources running more frequently than under our proposed plan. In others, it prevents our base load units from backing down as much to accommodate wind. Table 4.9 compares the PVRRs of the No New Wind scenario with our proposed plan.

Table 4.9
PVRR Differences Between Proposed Plan and No New Wind Scenario

PVRR ($000s)	Proposed plan	No New Wind	Difference
Base	$90,702,859	$89,302,895	-$1,399,963
High Gas	$92,184,890	$91,445,271	-$739,619
Low Gas	$89,192,022	$87,195,101	-$1,996,921
High CO2	$96,328,301	$95,746,824	-$581,477
Low CO2	$88,058,510	$86,279,304	-$1,779,205
Late CO2	$88,445,801	$86,856,079	-$1,589,722
No CO2	$85,087,884	$82,875,738	-$2,212,145
High Load	$96,466,131	$94,538,706	-$1,927,425
Low Load	$86,582,937	$84,459,291	-$2,123,647

The emission differences between the two scenarios are presented in Table 4.10.

Table 4.10
Emissions Comparison
Tons Emitted, 2010-2049

	Plan	No New Wind	No New Wind % Diff from Plan
SOx	1,021,188	1,267,538	24.1%
NOx	703,926	859,264	22.1%
CO2	969,920,472	1,138,389,108	17.4%
CO	137,292	152,184	10.8%
PM10	106,772	126,307	18.3%
VOCs	20,941	23,015	9.9%
HG	30,272	34,930	15.4%

Under the assumptions used for wind generation in this modeling analysis, the No New Wind scenario has a lower PVRR than our proposed plan under all sensitivities except one. This modeling is based on the cost of wind we've seen in this region recently. If wind prices remain at this level and gas prices are similar to our forecast, the wind additions in our proposed plan do not appear to be cost-effective.

Our Five Year Action plan takes this analysis into account. As discussed more fully in the Renewable Energy chapter, our plan is to issue an RFP for up to 250 MW of additional wind to be installed by the end of 2012 in order to take advantage of the federal Production Tax Credit before it expires. However, if we do not see wind prices that are competitive with alternative resources, we have the flexibility to defer additional wind, and utilize our bank of Renewable Energy Credits to comply with our renewable energy obligations. See Table 4.10 below.

Evaluation of Proposed Plan to Comparison Scenarios

A quick review and comparison of these expansions plans shows important differences. Table 4.11 shows the differences in the types and amounts of generic generation additions between the plans.

Table 4.11
Types and amounts of
generic generation additions by scenario (2010-2025)

Expansion Plan	Nat Gas CC	Nat Gas CT	SC Coal	Wind	DSM
Proposed plan	730 MW	1365 MW	0 MW	1750 MW	1682 MW
No New Wind	730 MW	1365 MW	0 MW	0 MW	1682 MW
ND/SD		1560 MW	2000 MW	0 MW	0 MW

Figures 4.3, 4.4, and 4.5 shows the differences in the energy mixes of the three plans, over the course of the planning period.

Figure 4.3
Proposed Plan Energy Mix in 2025

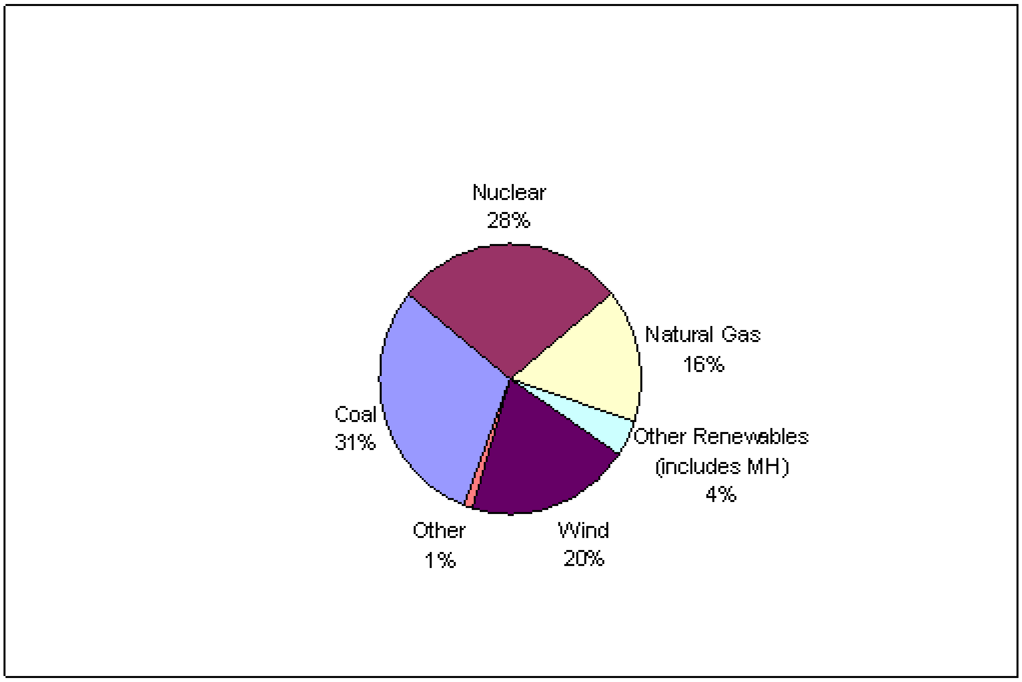


Figure 4.4
ND/SD Proposed Energy Mix in 2025

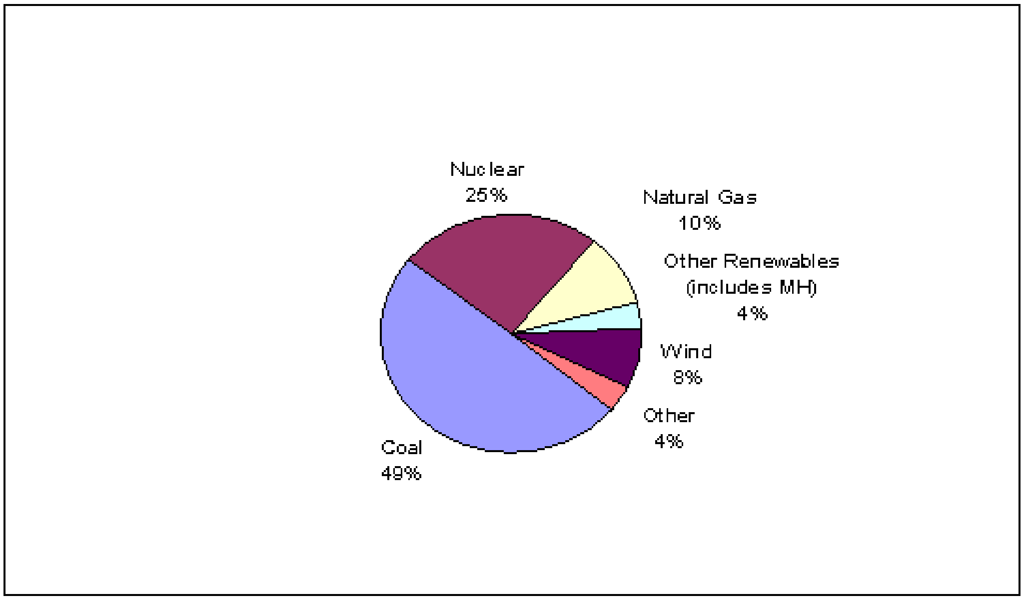
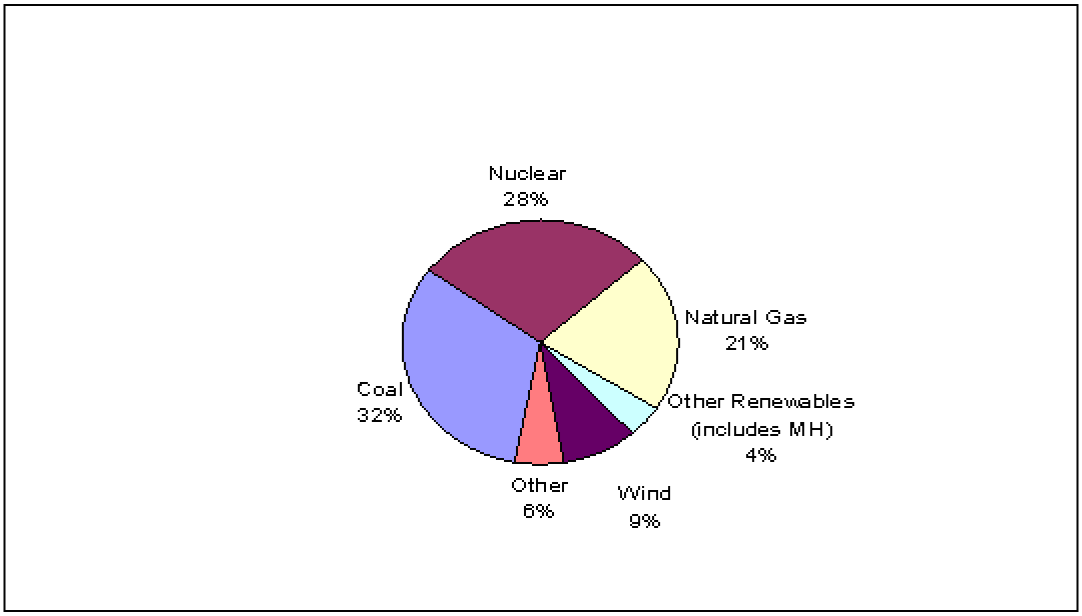


Figure 4.5
No New Wind Energy Mix in 2025



These pie charts demonstrate that the ND/SD scenario relies much more heavily on coal over the planning period than does the proposed plan – 49% as compared with 31% for the proposed plan and 32% for the No New Wind scenario. Also, the No New Wind Scenario relies more heavily on natural gas than the other two – 21% versus 10% for the ND/SD scenario and 16% for the proposed plan.

Finally, the 2025 energy mix pie chart for the proposed shows that our plan results in a very diverse and robust mix of generation resources. By not relying too heavily on one resource, and instead balancing the fuel mix among several resources, our proposed plan minimizes the potential for volatility and disruption.

Cost impact comparisons

Table 4.12 shows the relative cost increases of each scenario for selected years, shown in as a fraction of a dollar per kilowatt-hour provided. These figures are in 2010 dollars, normalized for DSM[1], and do not include either carbon planning costs or externality values.

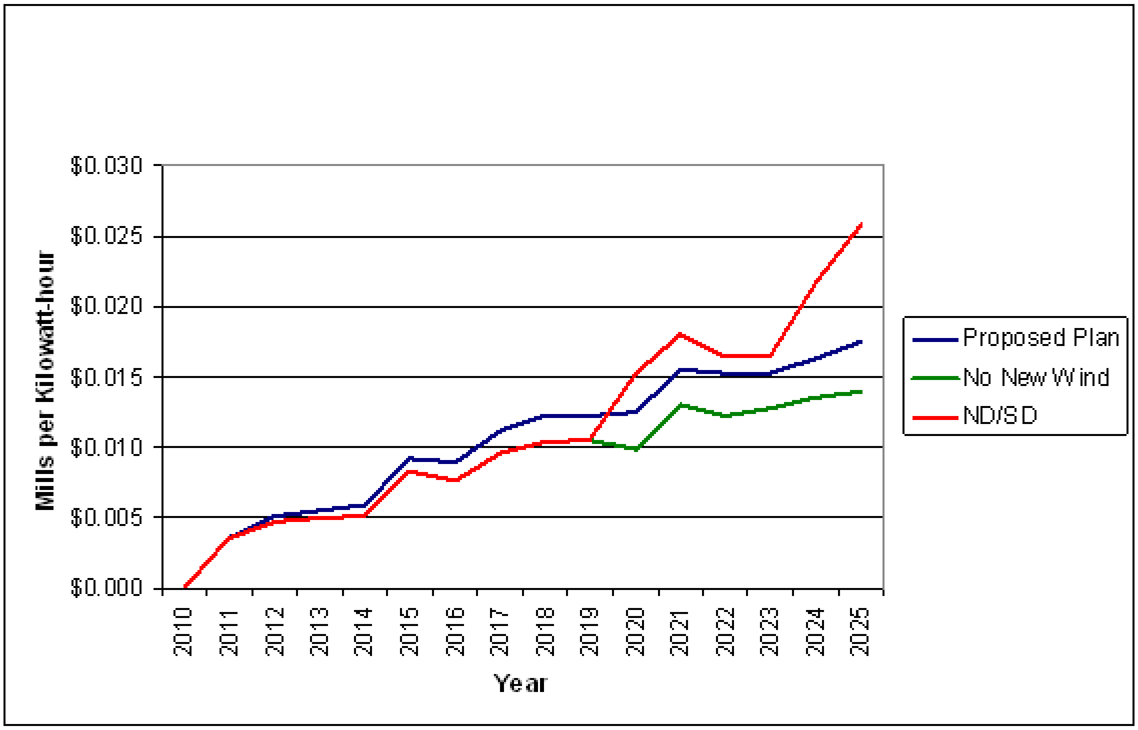
Table 4.12
Relative cost increases by scenario for selected years ($2010/kwh)

	2015 Increase over 2010	2020 Increase over 2010	2025 Increase over 2010
Proposed plan	$0.009	$0.013	$0.017
No New Wind	$0.008	$0.010	$0.014
ND/SD w/ DSM	$0.008	$0.015	$0.026

Another way to look at these cost impact comparisons is by charting the increases over the full planning period, as has been done in Figure 4.6.

[1] Elminating DSM from the ND/SD scenario increases total system costs for that scenario because more supply is needed. But because those costs are spread over more kilowatt-hours, the cost increase per kilowatt-hour is skewed. Incorporating DSM into this scenario allows the use of the same number of kilowatt-hours in the denominator.

Figure 4.6
Relative Cost Increases by Scenario 2010-2025



As can be seen from this graph, the ND/SD scenario and the No New Wind scenarios have a lower incremental cost per kilowatt-hour than our proposed plan, through the first decade of the planning period. However in 2020, the incremental cost per kilowatt-hour of the ND/SD scenario increases dramatically. That is the year when the first of three new supercritical coal plants would be added under that scenario.

The relative incremental difference between the cost per kilowatt-hour of the proposed plan and the No New Wind scenario reflects the incremental cost of compliance with our renewable energy obligations, most notably, the Minnesota RES. That difference is 1 mill per kwh by 2015, growing to 3 mills by 2020.

Conclusion

Xcel Energy proposes a plan that combines reasonable, fuel diversity, and account for current and expected environmental regulation. As we discuss in subsequent chapters it provides considerable flexibility to adjust as more clarity emerges around key policy decisions. Implementation of this plan over the next several years will allow us to operate our system efficiently and meet our customers' needs at an overall reasonable cost that has great potential to save customers cost over the longer run. Resource additions to our system represent a diverse mix of fuels, with new energy coming from wind, coal, nuclear, hydro and natural gas.