# MINNESOTA RESOURCE ASSESSMENT STUDY

## *SUPPLEMENTED WITH RESPONSES TO QUESTIONS POSED AT THE LEGISLATIVE ENERGY COMMISSION AT ITS OCTOBER 23, 2009 HEARING*

PREPARED BY THE
MINNESOTA OFFICE OF ENERGY SECURITY
AND THE RELIABILITY ADMINISTRATOR

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# TABLE OF CONTENTS

stakeholders questioned whether such an approach would create useful results or cause confusion. In response to stakeholders' comments, the ORA did not force gas or coal units into the model as initially proposed. However, when ORA did not force wind generation units, but instead allowed the model to choose wind as an expansion option, a modeling error occurred.[15] Therefore, to correct for the modeling error, the ORA had to force the RES-compliant quantity wind into the model with sensitivity scenarios that did not allow any additional wind. The cost of the RES can then be evaluated by comparing the results of the models with and without RES-compliant wind in the model. In addition, the ORA ran a scenario which applied the RES to the entire load served by Minnesota utilities in the model (not just Minnesota load). As noted above, IPL, Xcel and OTP have significant amounts of load outside of Minnesota which may be subject to other state renewable requirements or a national RES. The specific scenarios are discussed in more detail in Section V of this report.

### 9. *Reserve Margin*

The Reserve Margin of 15 percent used by MISO in 2008 MTEP was used in the model.

### 10. *Remaining Data from MISO*

The ORA used the data obtained from MISO for any inputs not specified above. No changes were made to the data provided by MISO for generation variable costs, generation fixed costs, generation unit maintenance, or generation forced outage rates. MISO used the default data from PowerBase, a separate tool licensed by MISO that contains data necessary to run Strategist, for each of these inputs.

## *E. RESULTS*

The ORA reminds readers that these studies and results are only for the first step in high-level resource assessment and planning purposes. As such, these studies and the report cannot be considered as justification for or against any particular proposal or resource option. *Appendix B contains* ~~Below is~~ a description of results under the following five overall scenarios:

- Scenario I: Achievement of the 1.5 percent DSM goal and compliance with the RES
- Scenario II: No additional wind
- Scenario III: High load (high demand for electricity)
- Scenario IV: High load and no new wind additions
- Scenario V: National RES

As discussed above, each scenario has a number of sensitivity runs, including different levels of $CO_2$ costs, different capital costs, and different levels of certain fuel costs. The results are reported as the number of units chosen compared to the results of the base case and the change in the present value of societal cost (which represents the costs of the run in today's dollars) for each sensitivity run compared to the base case.

[15] Technically, the model exceeded the limit on the number of "states" or variations in the Strategist model and could not be run to 2025.

*SCENARIO I: ACHIEVEMENT OF THE 1.5 PERCENT DSM GOAL AND COMPLIANCE WITH THE RES*

Tables 5 through 7 summarize the results of the different scenarios run on the base case assumptions.

**Table 5: Number of 500 MW Coal Units Added 2008-2025**

| | Base Assumptions | $4 $CO_2$ | $30 $CO_2$ | $45 $CO_2$ | Capital Cost +20% | Capital Cost minus 20% | Coal K Cost +20% | Coal K Cost minus 20% | Coal K Cost minus 20% and NG Cost +20% | Coal Fuel +20% | Coal Fuel minus20% | Gas Fuel +20% | Gas Fuel minus 20% | Gas Fuel +50% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Base Case | 1 | 1 | 0 | 0 | 0 | 3 | 0 | 5 | 7 | 0 | 1 | 3 | 0 | 5 |

**Table 6: Number of 627 MW Combined Cycle Units Added 2008-2025**

| | Base Assumptions | $4 $CO_2$ | $30 $CO_2$ | $45 $CO_2$ | Capital Cost +20% | Capital Cost minus 20% | Coal K Cost +20% | Coal K Cost minus 20% | Coal K Cost minus 20% and NG Cost +20% | Coal Fuel +20% | Coal Fuel minus 20% | Gas Fuel +20% | Gas Fuel minus 20% | Gas Fuel +50% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Base Case | 5 | 5 | 5 | 6 | 5 | 4 | 5 | 4 | 0 | 5 | 5 | 4 | 5 | 1 |

***Table 7: PV Societal Cost - Difference from Base (000s $)***

| | 1.5% DSM and RES |
|---|---|
| Base ($17 $CO_2$) | 0 |
| $4 $CO_2$ | -20,048,416 |
| $30 $CO_2$ | 19,941,024 |
| $45 $CO_2$ | 42,937,408 |
| Capital Cost +20% | 2,424,784 |
| Capital Cost -20% | -2,669,248 |
| Coal K Cost +20% | 21,184 |
| Coal K Cost -20% | -490,808 |
| Coal K Cost -20% and NG Cost +20% | 1,762,984 |
| Coal Fuel +20% | 3,232,232 |
| Coal Fuel -20% | -3,287,768 |
| Gas Fuel +20% | 1,693,048 |
| Gas Fuel -20% | -2,254,560 |
| Gas Fuel +50% | 3,419,664 |

***The figures shown in Table 7 need to be viewed carefully. The figures do not show which expansion plan is least-cost; instead, the figures show how, under differing assumptions, costs***

***of each plan change compared to the base case. For example, the $4 $CO_2$ contingency has the largest reduction of all contingencies compared to the Base, where a $17 $CO_2$ cost was used. However, the difference in cost is largely attributable to the lower cost per ton of $CO_2$ emitted being applied to the entire generation fleet, including existing generation. As a result, the difference in cost says more about the effects of lower carbon costs on the existing fleet rather than providing information about the best expansion plan. Conclusions which can be drawn from Table 7 are that $CO_2$ costs can be expected to have a significant effect on energy costs in Minnesota, due to Minnesota's large fleet of carbon-emitting power plants. Other factors which will influence energy costs in Minnesota are (by order of magnitude): coal fuel costs, capital costs and natural gas fuel costs. These factors will affect the selection of least-cost resources to meet energy needs in Minnesota, as suggested by the differing results in tables 5 and 6 above.***

***The results of this Scenario suggest that 1 coal unit and 5, 627 MW combined-cycle units would be the starting point for consideration during the 2008-2025 study period, with varying levels under differing contingencies, as indicated in Tables 5 and 6 above.***

SCENARIO II: NO ADDITONAL WIND

In order to investigate the cost-effectiveness of the RES and to gain some understanding of the effect of the RES on Minnesota in the future, the ORA ran the base case assumptions as explained in Section IV above, but did not add any additional wind generation. The same contingencies were run on the "no additional wind" scenario.

Tables 9 through 10 summarize the results of the different contingencies run on the No Additional Wind scenario.

***Table 9: Number of 500 MW Coal Units Added 2008-2025***

| | Base Assumptions | $4 $CO_2$ | $30 $CO_2$ | $45 $CO_2$ | Capital Cost +20% | Capital Cost minus 20% | Coal K Cost +20% | Coal K Cost minus 20% | Coal K Cost minus 20% and NG Cost +20% | Coal Fuel +20% | Coal Fuel minus 20% | Gas Fuel +20% | Gas Fuel minus 20% | Gas Fuel +50% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No Additional Wind | 4 | 6 | 0 | 0 | 1 | 6 | 1 | 7 | 8 | 1 | 6 | 6 | 0 | 8 |

***Table 10: Number of 627 MW Combined Cycle Units Added 2008-2025***

| | Base Assumptions | $4 $CO_2$ | $30 $CO_2$ | $45 $CO_2$ | Capital Cost +20% | Capital Cost minus 20% | Coal K Cost +20% | Coal K Cost minus 20% | Coal K Cost minus 20% and NG Cost +20% | Coal Fuel +20% | Coal Fuel minus 20% | Gas Fuel +20% | Gas Fuel minus 20% | Gas Fuel +50% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No Additional Wind | 4 | 2 | 7 | 7 | 6 | 2 | 6 | 1 | 1 | 6 | 2 | 2 | 6 | 1 |

Table 11, below, shows the costs under of the No Additional Wind Scenarios under different contingencies. Table 11 also includes the costs under all contingencies run on the base case so that the cost-effectiveness of the RES can be analyzed under these contingencies. Of the 14 different contingencies analyzed, the RES is cost-effective under 8 contingencies.

**Table 11: PV Societal Cost - Difference from Base (000s $)**

| ***Lower Costs in Bold*** | | |
|---|---|---|
| | 1.5% DSM and RES | 1.5% DSM No RES |
| BASE (\$17 $CO_2$) | **0** | 180,040 |
| \$4 $CO_2$ | -20,048,416 | **-22,762,904** |
| \$30 $CO_2$ | **19,941,024** | 22,487,392 |
| \$45 $CO_2$ | **42,937,408** | 47,816,488 |
| Capital Cost +20% | 2,424,784 | **1,208,384** |
| Capital Cost -20% | **-2,669,248** | -1,503,760 |
| Coal K Cost +20% | **21,184** | 534,752 |
| Coal K Cost -20% | -490,808 | **-1,263,296** |
| Coal K Cost -20% and NG Cost +20% | 1,762,984 | **1,416,392** |
| Coal Fuel +20% | **3,232,232** | 3,826,016 |
| Coal Fuel -20% | -3,287,768 | **-3,611,672** |
| Gas Fuel +20% | **1,693,048** | 1,751,656 |
| Gas Fuel -20% | -2,254,560 | **-2,883,576** |
| Gas Fuel +50% | **3,419,664** | 3,451,880 |

***The results of this Scenario suggest that 4 coal units and 4, 627 MW combined-cycle units would be the starting point for consideration during the 2008-2025 study period, with varying levels under differing contingencies, as indicated in Tables 9 and 10 above.***

*SCENARIO III: HIGH LOAD*

To investigate the effects of higher load, the study uses the Base Case with 1.0 Percent DSM instead of 1.5 Percent DSM. Tables 13 through 15 summarize the results of the different contingencies run on the High Load scenario.

**Table 13: Number of 500 MW Coal Units Added 2008-2025**

| | Base Assumptions | $4 $CO_2$ | $30 $CO_2$ | $45 $CO_2$ | Capital Cost +20% | Capital Cost minus 20% | Coal K Cost +20% | Coal K Cost minus 20% | Coal K Cost minus 20% and NG Cost +20% | Coal Fuel +20% | Coal Fuel minus 20% | Gas Fuel +20% | Gas Fuel minus 20% | Gas Fuel +50% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High Load Scenario | 0 | 3 | 0 | 0 | 0 | 5 | 0 | 5 | 8 | 0 | 1 | 4 | 0 | 6 |

**Table 14: Number of 627 MW Combined Cycle Units Added 2008-2025**

| | Base Assumptions | $4 $CO_2$ | $30 $CO_2$ | $45 $CO_2$ | Capital Cost +20% | Capital Cost minus 20% | Coal K Cost +20% | Coal K Cost minus 20% | Coal K Cost minus 20% and NG Cost +20% | Coal Fuel +20% | Coal Fuel minus 20% | Gas Fuel +20% | Gas Fuel minus 20% | Gas Fuel +50% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High Load Scenario | 7 | 3 | 7 | 7 | 7 | 3 | 7 | 3 | 0 | 7 | 6 | 3 | 7 | 2 |

***Table 15: PV Societal Cost - Difference from Base (000s $)***

| | |
|---|---|
| | 1.0% DSM and RES |
| BASE ($17 $CO_2$) | 4,453,768 |
| $4 $CO_2$ | -16,007,720 |
| $30 $CO_2$ | 24,706,408 |
| $45 $CO_2$ | 48,092,968 |
| Capital Cost +20% | 7,187,632 |
| Capital Cost -20% | 1,412,336 |
| Coal K Cost +20% | 4,453,768 |
| Coal K Cost -20% | 3,801,656 |
| Coal K Cost -20% and NG Cost +20% | 6,340,280 |
| Coal Fuel +20% | 7,688,112 |
| Coal Fuel -20% | 1,147,104 |
| Gas Fuel +20% | 6,300,272 |
| Gas Fuel -20% | 1,884,256 |
| Gas Fuel +50% | 8,163,504 |

***The results of this Scenario suggest that 0 coal units and 7, 627 MW combined-cycle units would be the starting point for consideration during the 2008-2025 study period, with varying levels under differing contingencies, as indicated in Tables 13 and 14 above.***

*SCENARIO IV: HIGH LOAD AND NO NEW WIND ADDITIONS.*

As in Section V.B, above, in order to assess the cost-effectiveness of the RES and to understand the effect of the RES on Minnesota in the future, the ORA ran a scenario that includes a forecast assuming energy savings of 1.0 percent of retail sales, but did not allow any additional wind generation to be added. This scenario is referred to as the "High Load and No New Wind" scenario. The ORA ran the same contingencies on the High Load and No New Wind scenario as on the High Load scenario.

Tables 17 through 19 summarize the results of the different contingencies run on the High Load and No Additional Wind scenario.

**Table 17: Number of 500 MW Coal Units Added 2008-2025**

| | Base Assumptions | \$4 $CO_2$ | \$30 $CO_2$ | \$45 $CO_2$ | Capital Cost +20% | Capital Cost minus 20% | Coal K Cost +20% | Coal K Cost minus 20% | Coal K Cost minus 20% and NG Cost +20% | Coal Fuel +20% | Coal Fuel minus 20% | Gas Fuel +20% | Gas Fuel minus 20% | Gas Fuel +50% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High Load and No New Wind Additions | 4 | 6 | 1 | 0 | 1 | 7 | 1 | 8 | 9 | 4 | 6 | 7 | 0 | 8 |

**Table 18: Number of 627 MW Combined Cycle Units Added 2008-2025**

| | Base Assumptions | \$4 $CO_2$ | \$30 $CO_2$ | \$45 $CO_2$ | Capital Cost +20% | Capital Cost minus 20% | Coal K Cost +20% | Coal K Cost minus 20% | Coal K Cost minus 20% and NG Cost +20% | Coal Fuel +20% | Coal Fuel minus 20% | Gas Fuel +20% | Gas Fuel minus 20% | Gas Fuel +50% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High Load and No New Wind Additions | 4 | 3 | 7 | 8 | 7 | 2 | 7 | 1 | 1 | 4 | 3 | 2 | 7 | 1 |

**Table 19: PV Societal Cost - Difference from Base (000s $)**

| *Lower Cost in Bold* | 1.0% DSM and RES | 1.0% DSM No RES |
|---|---|---|
| BASE ($17 $CO_2$) | **4,453,768** | 4,623,296 |
| $4 $CO_2$ | -16,007,720 | **-19,037,608** |
| $30 $CO_2$ | **24,706,408** | 27,553,648 |
| $45 $CO_2$ | **48,092,968** | 53,427,320 |
| Capital Cost +20% | 7,187,632 | **5,922,184** |
| Capital Cost -20% | **1,412,336** | 2,655,024 |
| Coal K Cost +20% | **4,453,768** | 5,118,400 |
| Coal K Cost -20% | 3,801,656 | **2,991,224** |
| Coal K Cost -20% and NG Cost +20% | 6,340,280 | **6,129,496** |
| Coal Fuel +20% | **7,688,112** | 8,379,328 |
| Coal Fuel -20% | 1,147,104 | **682,080** |
| Gas Fuel +20% | **6,300,272** | 6,353,808 |
| Gas Fuel -20% | 1,884,256 | **1,221,920** |
| Gas Fuel +50% | **8,163,504** | 8,354,208 |

***The results of this Scenario suggest that 4 coal units and 4, 627 MW combined-cycle units would be the starting point for consideration during the 2008-2025 study period, with varying levels under differing contingencies, as indicated in Tables 17 and 18 above.***

*SCENARIO V: NATIONAL RENEWABLE ENERGY STANDARD.*

Uses Base Case Assumptions with enough wind additions so that 25 percent of energy is produced from renewable sources by 2025. This scenario applies the RES to the out-of-state load that is used in the model as well as the Minnesota load. ***Under this Scenario 0 coal units and 6, 627 MW combined-cycle units are added during the 2008-2025 study period.***

### *E1. ADDITIONAL SCENARIO ANALYSIS IN RESPONSE TO QUESTIONS AND COMMENTS FROM THE LEGISLATIVE ENERGY COMMISSION*

***In response to the question and comments received by the ORA at the October 23, 2009 Legislative Energy Commission meeting, the ORA analyzed several additional scenarios of potential resource expansions. These scenarios include: extensions and expansions of the purchases from Manitoba Hydro, the addition of a nuclear facility as an expansion option, and an increase in conservation to 2% of retail sales. The ORA explains the results of these scenarios below:***

*1. Extension and Expansion of Manitoba Hydro.*

***In its initial runs, the ORA allowed the current contracts with Manitoba Hydro to expire as scheduled. In this additional run, the existing contracts were assumed to be available for the entire study period; further, the Manitoba Hydro resource was increased according to an***

*option modeled in Xcel's IRP which assumed that a new transmission line would be built by 2021. The additional capacity from Manitoba Hydro is shown in the Table below.*

*Adding the Manitoba Hydro Extension and Expansion to the base assumptions from Scenario I of the Report results in the following expansion plan. Essentially, this plan would select no coal resources, and would use Manitoba Hydro resources and a combination of natural gas and wind facilities.*

*Table E1*

| YEAR | COAL | CC | IGCC | CT | WIND | IGSQ[16] | Hydro[17] |
|---|---|---|---|---|---|---|---|
| 2008 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2009 | 0 | 0 | 0 | 1 | 3 | 0 | |
| 2010 | 0 | 0 | 0 | 0 | 3 | 0 | |
| 2011 | 0 | 0 | 0 | 0 | 4 | 0 | |
| 2012 | 0 | 1 | 0 | 0 | 3 | 0 | |
| 2013 | 0 | 0 | 0 | 0 | 3 | 0 | |
| 2014 | 0 | 0 | 0 | 0 | 3 | 0 | |
| 2015 | 0 | 0 | 0 | 0 | 3 | 0 | 375 MW |
| 2016 | 0 | 1 | 0 | 0 | 2 | 0 | 535 MW |
| 2017 | 0 | 0 | 0 | 0 | 2 | 0 | |
| 2018 | 0 | 1 | 0 | 0 | 2 | 0 | |
| 2019 | 0 | 0 | 0 | 0 | 3 | 0 | |
| 2020 | 0 | 0 | 0 | 0 | 1 | 0 | |
| 2021 | 0 | 0 | 0 | 0 | 2 | 0 | |
| 2022 | 0 | 1 | 0 | 0 | 1 | 0 | 125 MW |
| 2023 | 0 | 0 | 0 | 0 | 2 | 0 | |
| 2024 | 0 | 1 | 0 | 0 | 2 | 0 | |
| 2025 | 0 | 0 | 0 | 0 | 1 | 0 | |
| Total: | 0 | 5 Units (3135 MW) | 0 | 1 Unit (168MW) | 40 Units (4000 MW) | 0 | 1035 MW |

***As noted above, the hydro additions were modeled based on assumptions that existing contracts would be extended and Xcel's contracts with Manitoba Hydro would be expanded based on data from Xcel's IRP. In modeling the hydro resource, the ORA modeled a specific resource, instead of allowing the model to choose a generic hydro resource. The ORA analyzed hydro additions in this way because there are very limited opportunities to expand hydro resources within the state. For example, the*** **U.S. Hydropower Resource Assessment for Minnesota** ***prepared by the Idaho National Engineering Laboratory for the United States Department of Energy (published July 1996) shows a total undeveloped capacity of 137 MW for Minnesota and no single site in Minnesota that was greater than 50 MW. Therefore, any expansion of hydro power is likely to be imported.***

[16] IGSQ is an integrated gasification combined cycled (IGCC) unit with partial $CO_2$ sequestration.
[17] Manitoba Hydro additions shown in MW based on IRP data.

*The closest significant hydro resources are in Manitoba, Canada. In order to use the hydro resources available from Manitoba Hydro, Minnesota utilities will have to negotiate extensions of existing contracts and enter into new contracts for any future capacity that becomes available. Manitoba Hydro is intending to expand its resources in 2021; thus the ORA included the 125 MW expansion which may be available at that time as indicated by Xcel in its IRP. Additional purchases from Manitoba Hydro will depend on availability and cost. If cost-effective, additional hydro resource may be available from Manitoba Hydro after 2021. Any additional hydropower could be used to meet future growth or replace existing resources.*

*For ease of comparison, the results of Scenario I under the base assumptions without the Manitoba Hydro Extension and Expansion are shown below:*

*Table E2*

| YEAR | COAL | CC | IGCC | CT | WIND | IGSQ |
|---|---|---|---|---|---|---|
| 2008 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2009 | 0 | 0 | 0 | 1 | 3 | 0 |
| 2010 | 0 | 0 | 0 | 0 | 3 | 0 |
| 2011 | 0 | 0 | 0 | 0 | 4 | 0 |
| 2012 | 0 | 0 | 0 | 1 | 3 | 0 |
| 2013 | 0 | 1 | 0 | 0 | 3 | 0 |
| 2014 | 0 | 0 | 0 | 0 | 3 | 0 |
| 2015 | 0 | 1 | 0 | 0 | 3 | 0 |
| 2016 | 0 | 1 | 0 | 0 | 2 | 0 |
| 2017 | 0 | 0 | 0 | 0 | 2 | 0 |
| 2018 | 0 | 0 | 0 | 1 | 2 | 0 |
| 2019 | 0 | 1 | 0 | 0 | 3 | 0 |
| 2020 | 0 | 0 | 0 | 0 | 1 | 0 |
| 2021 | 0 | 0 | 0 | 0 | 2 | 0 |
| 2022 | 0 | 1 | 0 | 0 | 1 | 0 |
| 2023 | 0 | 0 | 0 | 0 | 2 | 0 |
| 2024 | 1 | 0 | 0 | 0 | 2 | 0 |
| 2025 | 0 | 0 | 0 | 0 | 1 | 0 |
| Total: | 1 | 5 | 0 | 3 | 40 | 0 |

*As shown above, the extension and expansion of the Manitoba Hydro purchases would reduce the additional capacity taken from coal by 500 MW, and increase the capacity taken from simple cycle combustion turbines by 170 MW during the 2008-2025 study period. Using the costs of the Manitoba Hydro purchases as modeled in IRPs, the extension and expansion would increase the present-value societal cost of the expansion model by about $8 million compared to the base case in Scenario I. As compared to the overall system cost this amount is an increase of 0.01%, meaning the expansion plan costs are very similar with and without the extension and expansion of the Manitoba Hydro resource.*

2. *Nuclear*

***Due to the existing moratorium on the construction of nuclear, the ORA did not include a nuclear expansion option in its initial analysis. However, per a request posed at the LEC, the ORA created a scenario with the option to choose nuclear units as a resource. In order to model nuclear power, the ORA used the data from a nuclear unit modeled in a recent proceeding before the Commission.[18] The nuclear unit modeled assumes a capacity of 500 MW and a capacity cost of approximately $5,000 per kW. This cost is within the range of that shown in the June 19, 2008 presentation by the Federal Energy Regulatory Commission's (FERC) Office of Enforcement that was provided by Missouri River Energy Systems (MRES) and attached as Appendix A to the initial report.***

***When modeling under the base assumptions in this Scenario, including a cost of $17 per ton for carbon, a nuclear option was not selected by the model.[19] The expansion plan remained the same as when a nuclear option was not allowed. In order to further investigate the potential for the addition of a nuclear resource, the ORA modeled $CO_2$ costs of $30 and $45 dollars per ton and allowed for a nuclear expansion option.***

***Using a $30 $CO_2$ cost, a 500 MW nuclear resource is selected near the end of the study period as shown below:***

*Table E3*

| YEAR | COAL | CC | IGCC | CT | NUKE | WIND | IGSQ |
|---|---|---|---|---|---|---|---|
| 2008 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2009 | 0 | 0 | 0 | 1 | 0 | 3 | 0 |
| 2010 | 0 | 0 | 0 | 0 | 0 | 3 | 0 |
| 2011 | 0 | 0 | 0 | 0 | 0 | 4 | 0 |
| 2012 | 0 | 0 | 0 | 1 | 0 | 3 | 0 |
| 2013 | 0 | 1 | 0 | 0 | 0 | 3 | 0 |
| 2014 | 0 | 0 | 0 | 0 | 0 | 3 | 0 |
| 2015 | 0 | 1 | 0 | 0 | 0 | 3 | 0 |
| 2016 | 0 | 1 | 0 | 0 | 0 | 2 | 0 |
| 2017 | 0 | 0 | 0 | 0 | 0 | 2 | 0 |
| 2018 | 0 | 0 | 0 | 1 | 0 | 2 | 0 |
| 2019 | 0 | 1 | 0 | 0 | 0 | 3 | 0 |
| 2020 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 2021 | 0 | 0 | 0 | 0 | 0 | 2 | 0 |
| 2022 | 0 | 1 | 0 | 0 | 0 | 1 | 0 |
| 2023 | 0 | 0 | 0 | 0 | 0 | 2 | 0 |
| 2024 | 0 | 0 | 0 | 0 | 1 | 2 | 0 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| Total: | 0 | 5 | 0 | 3 | 1 | 40 | 0 |

[18] *Source: Xcel's Petition for Approval of Eligibility of the Bay Front Project for Recovery under the Renewable Energy Standard Rider in Docket No. E002/M-09-821.*
[19] *Under the base assumptions, a $17 per ton $CO_2$ costs was used.*

*If a \$45 $CO_2$ cost is used, 2,000 MW of nuclear resource (4 500-MW units) would be added to the expansion plan, starting in 2019, as shown below:*

*Table E4*

| YEAR | COAL | CC | IGCC | CT | NUKE | WIND | IGSQ |
|---|---|---|---|---|---|---|---|
| 2008 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2009 | 0 | 0 | 0 | 1 | 0 | 3 | 0 |
| 2010 | 0 | 0 | 0 | 0 | 0 | 3 | 0 |
| 2011 | 0 | 0 | 0 | 0 | 0 | 4 | 0 |
| 2012 | 0 | 1 | 0 | 0 | 0 | 3 | 0 |
| 2013 | 0 | 0 | 0 | 0 | 0 | 3 | 0 |
| 2014 | 0 | 0 | 0 | 0 | 0 | 3 | 0 |
| 2015 | 0 | 1 | 0 | 1 | 0 | 3 | 0 |
| 2016 | 0 | 1 | 0 | 0 | 0 | 2 | 0 |
| 2017 | 0 | 0 | 0 | 0 | 0 | 2 | 0 |
| 2018 | 0 | 0 | 0 | 1 | 0 | 2 | 0 |
| 2019 | 0 | 0 | 0 | 0 | 1 | 3 | 0 |
| 2020 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 2021 | 0 | 0 | 0 | 0 | 1 | 2 | 0 |
| 2022 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 2023 | 0 | 0 | 0 | 0 | 1 | 2 | 0 |
| 2024 | 0 | 0 | 0 | 0 | 0 | 2 | 0 |
| 2025 | 0 | 0 | 0 | 0 | 1 | 1 | 0 |
| Total: | 0 | 3 | 0 | 3 | 4 | 40 | 0 |

*Under this set of assumptions, much of the additional capacity added would come from a nuclear resource with no coal units added. The energy for the added nuclear resources would be used to replace energy from coal resources due to the high cost of $CO_2$ emissions.*

### 3. *Additional Conservation*

***In its initial report, the ORA modeled conservation equal to 1.5 percent and 1.0 percent of annual retail energy sales based on the requirement of Minnesota Statute §216B.241. In response to questions from the LEC, the ORA added a scenario where energy savings of 2.0 percent of annual retail energy sales is achieved. As shown below, the added energy savings would result in 1 fewer 600 MW combined cycle turbine and an additional 170 MW simple cycle combustion turbine.***

*Table E4*

| YEAR | COAL | CC | IGCC | CT | NUKE | WIND | IGSQ |
|---|---|---|---|---|---|---|---|
| 2008 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2009 | 0 | 0 | 0 | 1 | 0 | 3 | 0 |
| 2010 | 0 | 0 | 0 | 0 | 0 | 3 | 0 |
| 2011 | 0 | 0 | 0 | 0 | 0 | 4 | 0 |
| 2012 | 0 | 0 | 0 | 0 | 0 | 2 | 0 |
| 2013 | 0 | 0 | 0 | 1 | 0 | 3 | 0 |
| 2014 | 0 | 0 | 0 | 0 | 0 | 3 | 0 |
| 2015 | 0 | 1 | 0 | 2 | 0 | 3 | 0 |
| 2016 | 0 | 1 | 0 | 0 | 0 | 2 | 0 |
| 2017 | 0 | 0 | 0 | 0 | 0 | 2 | 0 |
| 2018 | 0 | 0 | 0 | 0 | 0 | 2 | 0 |
| 2019 | 0 | 1 | 0 | 0 | 0 | 2 | 0 |
| 2020 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 2021 | 0 | 0 | 0 | 0 | 0 | 2 | 0 |
| 2022 | 0 | 1 | 0 | 0 | 0 | 1 | 0 |
| 2023 | 0 | 0 | 0 | 0 | 0 | 2 | 0 |
| 2024 | 1 | 0 | 0 | 0 | 0 | 2 | 0 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| Total: | 1 | 4 | 0 | 4 | 0 | 38 | 0 |

### 4. *More Renewable*

*Scenario V, included in the initial report, is a national RES scenario. In this scenario, the ORA applied Minnesota's RES requirement that 25% of energy would come from renewables to the out-of-state load in the model.*[20] *This scenario would add 2,100 MW of wind above what is required to meet the Minnesota RES and would add no coal resources. The results of that scenario are shown below:*

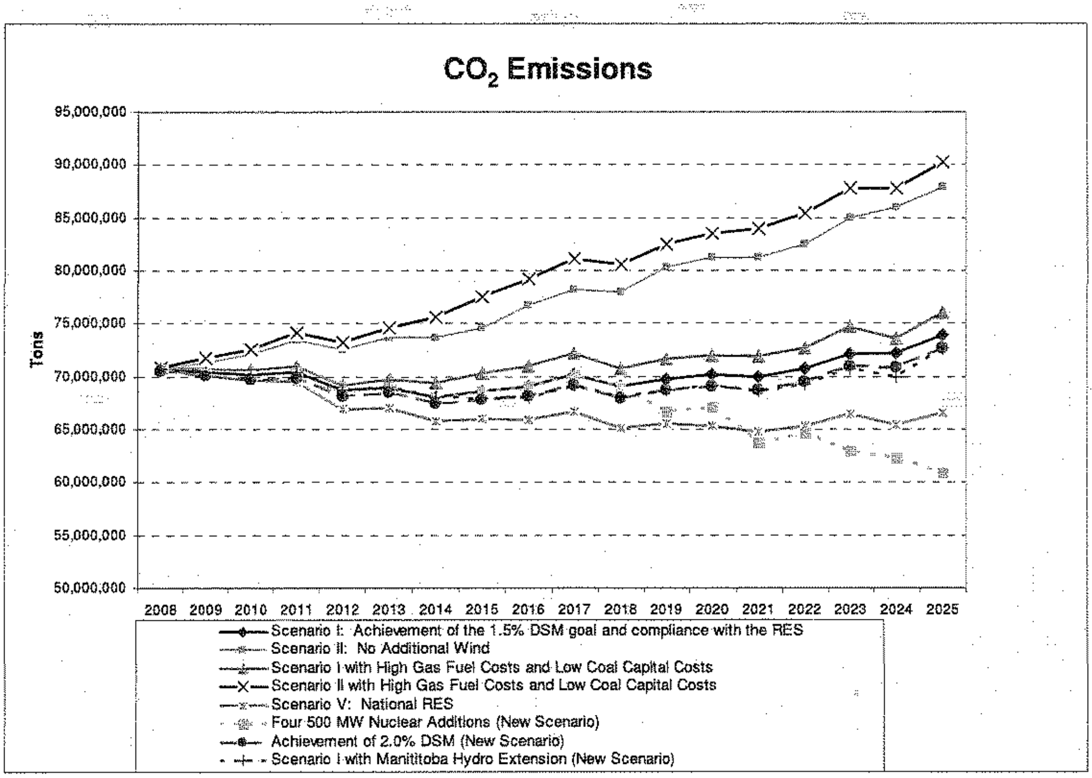
*Table E5*

| YEAR | COAL | CC | IGCC | CT | WIND | IGSQ |
|---|---|---|---|---|---|---|
| 2008 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2009 | 0 | 0 | 0 | 1 | 4 | 0 |
| 2010 | 0 | 0 | 0 | 0 | 4 | 0 |
| 2011 | 0 | 0 | 0 | 0 | 5 | 0 |
| 2012 | 0 | 1 | 0 | 0 | 5 | 0 |
| 2013 | 0 | 0 | 0 | 0 | 4 | 0 |
| 2014 | 0 | 0 | 0 | 0 | 4 | 0 |
| 2015 | 0 | 1 | 0 | 0 | 4 | 0 |
| 2016 | 0 | 1 | 0 | 0 | 4 | 0 |
| 2017 | 0 | 0 | 0 | 0 | 3 | 0 |
| 2018 | 0 | 1 | 0 | 0 | 3 | 0 |
| 2019 | 0 | 0 | 0 | 0 | 4 | 0 |
| 2020 | 0 | 0 | 0 | 0 | 3 | 0 |
| 2021 | 0 | 0 | 0 | 0 | 3 | 0 |
| 2022 | 0 | 1 | 0 | 0 | 2 | 0 |
| 2023 | 0 | 0 | 0 | 0 | 3 | 0 |
| 2024 | 0 | 1 | 0 | 0 | 3 | 0 |
| 2025 | 0 | 0 | 0 | 0 | 3 | 0 |
| Total: | 0 | 6 | 0 | 1 | 61 | 0 |

[20] *Various levels are being considered for a national RES. The ORA chose the level of 25% to study since this amount matches Minnesota's RES and the level for some surrounding states.*

5. $CO_2$ *Emissions*

***In response to questions regarding $CO_2$ emissions at the October 23, 2009 LEC meeting, the ORA prepared the graph below. The graph shows projected $CO_2$ emissions under several distinct scenarios. The three dotted lines correspond to new scenarios which were run in response to questions and comments from the LEC.***




***As shown above, there is a broad range of potential future $CO_2$ emissions under the scenarios modeled. Under the nuclear addition or national RES scenarios, emissions would decrease. Under several scenarios, including the Scenario I with the base assumptions, $CO_2$ emissions would remain relatively constant. Under other scenarios such as when no additional wind is added, $CO_2$ emissions would increase.***

6. *No Constraints or Mandates*

***As explained in Section D.8 of the intitial report, the ORA "forced" in enough wind to comply with the RES. When the ORA did not force wind generation units, but instead allowed the model to choose wind as an expansion option, a modeling error occurred.[21] Therefore, to correct for the modeling error, the ORA had to force the RES-compliant quantity wind into the model with sensitivity scenarios that did not allow any additional wind. The cost of the RES can then be evaluated by comparing the results of the models with and without RES-compliant wind in the model as shown in Table 11 above.***

[21] ***Technically, the model exceeded the limit on the number of "states" or variations in the Strategist model and could not be run to 2025.***