MEMORADUM

TO: Energy Supply TWG members

FROM: Bill Dougherty

CC: Randy Strait, J. David Thornton, Ed Garvey, Tom Peterson

DATE: 9 January 2008

RE: A brief description of the analytical results for each energy supply option

---

Dear Colleagues,

Following up yesterday's memo which offered a brief description of my understanding of each major assumption that has been made by the ES TWG for the analysis of mitigation option, below is a follow-up memo that provides a brief description of the analytical results for each of the seven energy supply options that have been quantified.

My approach is the memo below is to describe with brief text and charts - rather than with spreadsheets - the underlying basis for the last round of results for each option. My aim is to try and make clear why we are getting the GHG reduction and cost results, and to give you the opportunity to review and reflect on the assumptions and approach.

As you know, the consultative process is winding down. The final CCAG meeting is scheduled for 24 January 2008. This gives us just over two weeks to make any final changes/corrections to the analysis.

ES-1: Generation performance standards (GPS)

As described in the TWG's policy option description, this option is a mandate that requires those entities that deliver electricity to acquire electricity, or power plant developers to build and operate new base load generation, with a per-unit emission rate below a specified mandatory standard (1,110 pounds of CO2 per MWh for power stations; 1,300 lbs of CO2 per MWh for combined heat and power (CHP) stations). For a numerical summary, see the ES-1 tab in spreadsheet called "MN ES results through 2025.xls" sent on 7 January 2008.

The TWG has made the following key assumptions for the analysis of this option, as follows:

- The start year for the option is 2013.
- The GPS should affect all new capacity, whether already in the pipeline or not.
- The need for replacement power to replace generation from capacity affected by the GPS should be subjected to an assessment of whether such power is needed, given projected MN electricity sales demand. If needed, replacement power comes from out-of-state with a mix of 75% natural gas-fired and the balance from wind.

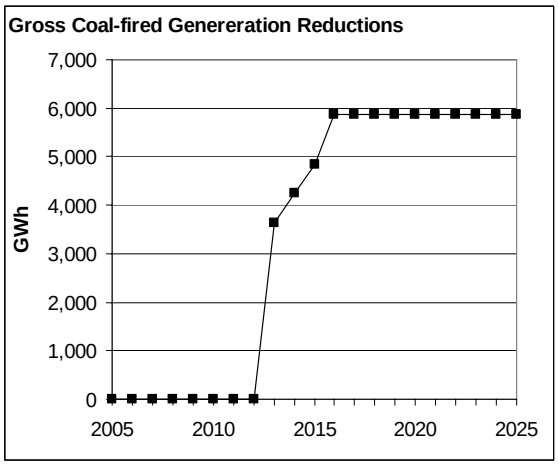
The TWG decided to assess the option under the following scenarios:

- Reference Scenario #1: All planned capacity additions; with the recently passed RES and CIP legislation
- Reference Scenario #2: All planned capacity additions except for large coal additions; with the recently passed RES and CIP legislation

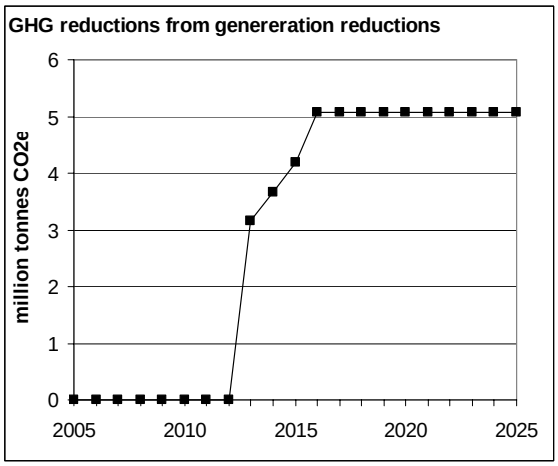
Broadly, the effect of implementing the assumptions is briefly summarized below for each of the scenarios analyzed:

- Reference Scenario #1: elimination of all new coal capacity in MN; no replacement power needed due to the fact that electricity demand can be met by a) the combination of MN generation without the contribution of the new coal stations and b) forecasted levels of imports;
- Reference Scenario #2: no effect as new coal capacity is eliminated as an assumption within the scenario.

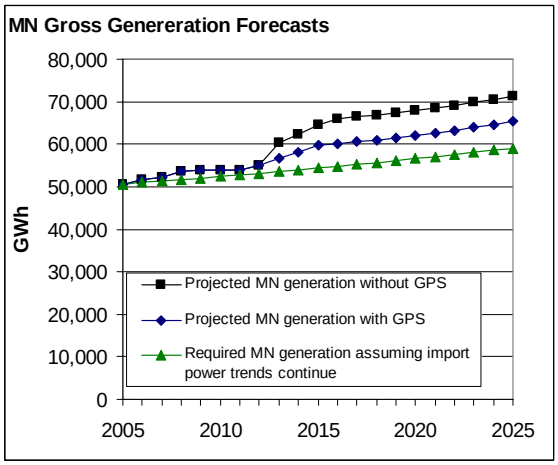
Regarding generation, the impact of the option is summarized in the chart below. The curve represents the total annual reductions associated with the elimination of new coal-fired generation in Reference Scenario #1.



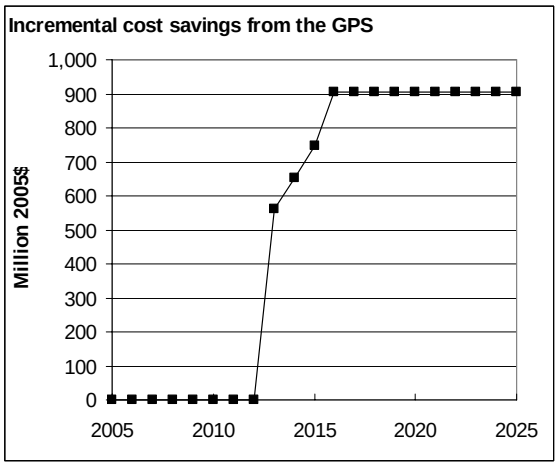
Regarding CO2-equivalent (CO2e) emission reductions, the impact of the option is summarized in the chart below. The curve represents the annual CO2e reductions associated with the elimination of new coal-fired generation in Reference Scenario #1. The annual emission reductions in 2015 and 2025 are 4.1 and 5.1 million tonnes CO2e, respectively. The cumulative emission reductions over the 2005-2025 forecast period are 61.8 million tonnes CO2e.



Regarding the need for replacement power, the impact of the option is summarized in the chart below. The middle curve is the projected gross generation in MN after the implementation of the GPS. The lower curve is the "required" MN gross generation under the assumption that the share of imported power to total power evident in 2005 continues through the end of the forecast period. As projected gross generation in MN after implementation of the GPS always exceed "required" MN gross generation, no replacement power is needed.



Regarding costs, there are savings associated with reduced capital costs, transmission costs, variable O&M costs, fixed O&M costs and fuel costs. The levelized capital costs for a pulverized coal and integrated gasification combined cycle (IGCC) station coming online in 2005 were assumed to be $69/MWh and $84/MWh, respectively (2005$, see yesterday's memo) and were escalated by a factor of 1.29 to account for the TWG's real escalation assumptions. The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. This is summarized in the chart below. The net present value of these annual costs are -$7.8 billion over the 2013-2025 period (2005$).



Regarding the cost effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, -$126/MWh (2005$) (i.e., -7.8 billion divided by 61.8 million tonnes and multiplied by a conversion factor of 1,000).

> *Note: I noticed that I used the levelized costs for an IGCC plant when calculating the cost savings. This gives an inflated estimate of the cost savings since some of the new coal capacity displaced by the GPS is pulverized coal. After correcting, the weighted average of the levelized costs for the coal capacity displaced is $146.5/MWh instead of the value of $154.0/MWh. The results for costs and cost-effectiveness after this correction are -$7.2 billion over the 2013-2025 period (2005$) and -$120/MWh (2005$).*

ES-3: Efficiency Improvements, Repowering and other Upgrades to Existing Plants

As described in the TWG's policy option description, this option would promote the identification and pursuit of cost-effective emissions reductions from existing generating units through improving their operating efficiency, adding biomass or other fuel changes, or adding carbon capture technology. It has been modeled thus far as a biomass co-firing option although the plan as per the 21 December TWG meeting is to also add a natural gas repowering component. This analysis is underway but has not been completed in time for the upcoming CCAG meeting. For a numerical summary, see the ES-3 tab in spreadsheet called "MN ES results through 2025.xls" sent on 7 January 2008.

The TWG has made the following key assumptions for the analysis of this option, as follows:

- The start year for the option is 2013.
- Biomass, harvested sustainably, represents a maximum of 8% of fuel combusted annually at pulverized coal power stations.
- The ramp-up period for full utilization of biomass in co-fired coal stations is 5 years.
- Woodwastes and forest residues are the major form of biomass to be used, at a flat price of $2.5/mmbtu (2005$).
- The impact of the option on biomass supplies in MN should be evaluated and supply/demand effects should be reflected in the price of biomass

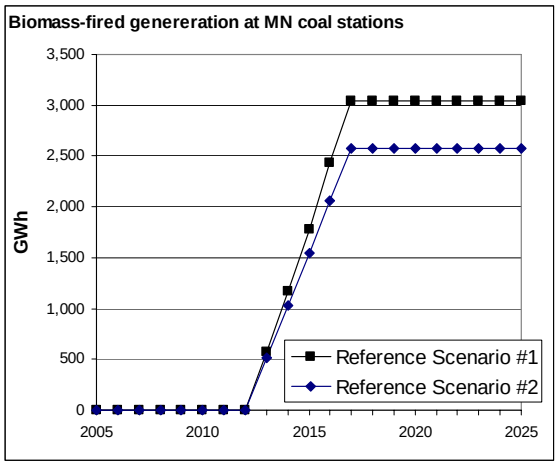
The TWG decided to assess the option under the following scenarios:

- Reference Scenario #1: All planned capacity additions; with the recently passed RES and CIP legislation
- Reference Scenario #2: All planned capacity additions except for large coal additions; with the recently passed RES and CIP legislation

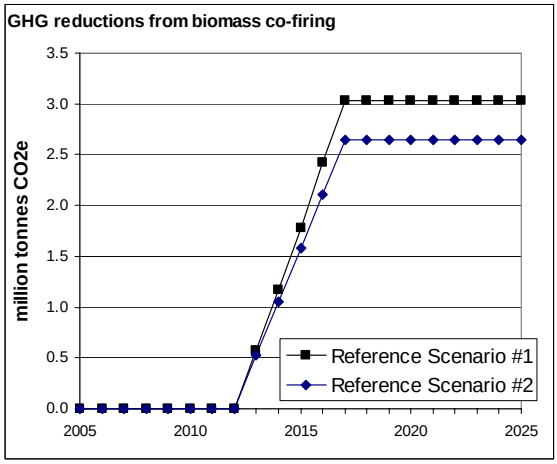
Broadly, the effect of implementing the assumptions is briefly summarized below for each of the scenarios analyzed:

- Reference Scenario #1: substantial GHG reductions at less than $20/tCO2e avoided;
- Reference Scenario #2: slightly less GHG reductions due to less coal on the system, also at less than $20/tCO2e avoided.

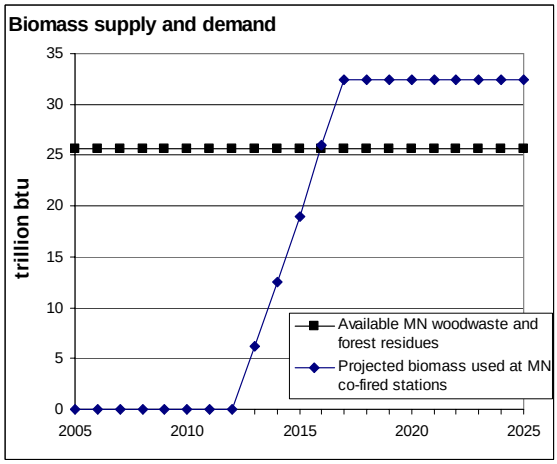
Regarding generation, the impact of the option is summarized in the chart below. The curves represents the total generation associated with biomass at co-fired coal stations in the Reference Scenarios.



Regarding CO2-equivalent (CO2e) emission reductions, the impact of the option is summarized in the chart below. The curves represents the annual CO2e reductions associated with biomass co-firing in the Reference Scenarios. The annual emission reductions in 2015 and 2025 are 1.8 and 3.0 million tonnes CO2e, respectively. The cumulative emission reductions over the 2005-2025 forecast period are 33.3 million tonnes CO2e.



Regarding the demand/supply situation for woodwastes and forest residues, the impact of the option is summarized in the chart below for Reference Scenario #1. The biomass supply projection is from your colleagues in the AFW TWG. By 2017, the projected biomass used at MN coal stations would exceed available MN supply.

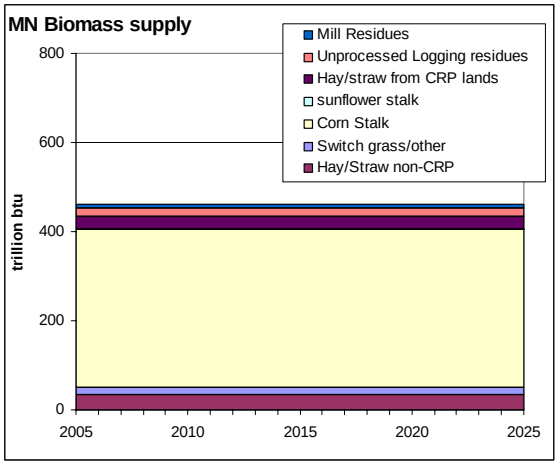


Regarding the total supply of biomass in MN, there are substantial additional quantities of less desirable biomass that could be used for co-firing, as summarized in the chart below. However, for these quantities to be able to be used for co-firing, case study literature suggests it would be necessary to add a gasifier to gasify the biomass prior to combustion to overcome the higher risk of wear, corrosion, slagging and fouling in the combustion system.[1] The incremental cost for adding a gasifier is $67.9 million.[2] When escalated according to TWG assumptions (see

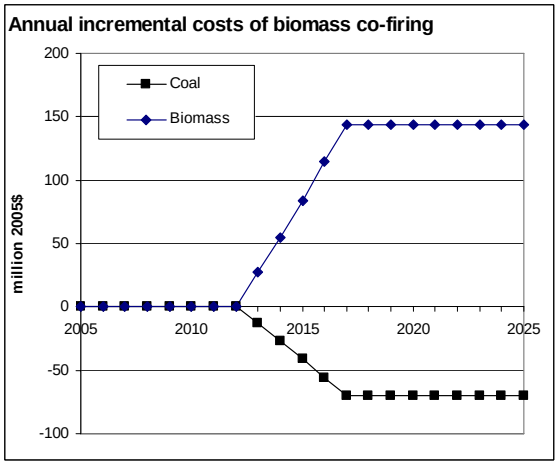
[1] See for example. Rosch, C., 2001. "Technical Constraints of Co-firing in Europe" available at http://books.google.com/books?id=I4md2B_nk9UC&pg=PA1299&lpg=PA1298&ots=sUbZBbabxG&dq=biomass+types+for+%22co+firing%22&sig=GIK_RJRRYx3FTgsf0OIdYg0xRWg#PPA1298,M1

[2] See report entitled "Biomass Gasification Combined Cycle - Agenda 2020" prepared by the Weyerhauser Company, (available at C:\projects\CCS\Minnesota\ES\Analysis\ES-3\Biomass Gasification Combined Cycle _ Agenda 2020_ Final Report.htm). see page 5-28 (for next plant design (as opposed to nth plant design). Figure includes direct/indirect costs, balance of plant items, and contingency.

yesterday's memo) and levelized, the additional cost for biomass co-firing in MN for use of less desirable biomass was $7.3/MWh (2005$).



Regarding the annual costs of the option, there are incremental costs from biomass associated with the capital cost for gasifier and the fuel cost (no incremental O&M costs were assumed) and incremental savings from coal associated with lower fuel costs, as summarized in the chart below. The net present value of these annual costs are $0.55 billion over the 2013-2025 period (2005$) for Reference Scenario #1.



Regarding the cost effectiveness of the option, it was calculated for Reference Scenario #1 as the quotient of the NPV and cumulative GHG emission reductions, $17/MWh (2005$) (i.e., 0.55 billion divided by 33.3 million tonnes and multiplied by a conversion factor of 1,000).

> *Note: I only report the cost results for Reference Scenario #1 in the discussion above. The results for Reference Scenario #2 have not been included in the summary provided to the CCAG for their 7th meeting on 10 January 2008.*

ES-4: Transmission System Upgrading, Including Reducing Transmission Line and Distribution System Loss

As described in the TWG's policy option description, this option would improve electricity transmission systems to reduce bottlenecks, enhance throughput, and improve the efficiency of

operations system wide. The option also targets reduction of leaks in natural gas pipelines to avoid methane emissions to the atmosphere and prevent the waste of valuable product.

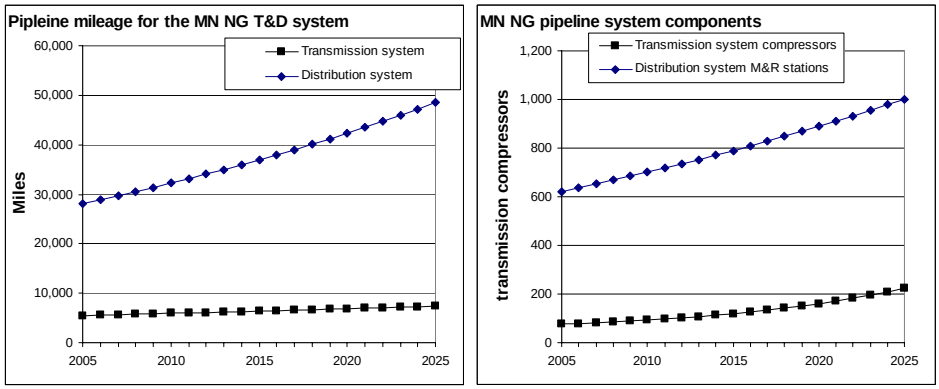
The option has been modeled thus far as a upgrade to the natural gas transmission and distribution pipeline system. This is due to the fact that the costs associated with upgrades to the electric transmission and distribution system remain speculative. For a numerical summary, see the ES-4 tab in spreadsheet called "MN ES results through 2025.xls" sent on 7 January 2008.

The TWG has not had an opportunity to review and reach consensus on a set of key assumptions for the analysis of this option. As placeholders until the TWG has the opportunity to provide feedback, the following was assumed:

- The start year for the option is 2010.
- The methane reduction target for the MN natural gas transmission system is 25% of projected emissions in 2025 in the Reference Case.
- The methane reduction target for the MN natural gas distribution system is 15% of projected emissions in 2025 in the Reference Case.
- The ramp-up period for full implementation of methane leak mitigation for the MN natural gas transmission system is 10 years.
- The ramp-up period for full implementation of methane leak mitigation for the MN natural gas transmission system is 8 years.

Broadly, the effect of implementing the assumptions is modest GHG reductions at negative value for cost effectiveness;

Regarding the characteristics of the MN natural gas transmission system, the chart below summarizes the total projected mileage for both the transmission and distribution system (left), and the total projected number of compressors for the transmission system and the total number of metering and regulating (M&R) stations for the distribution system (right).



For the MN natural gas transmission system, there were several mitigation option analyzed for their collective impact on reducing methane leaks, as follows:

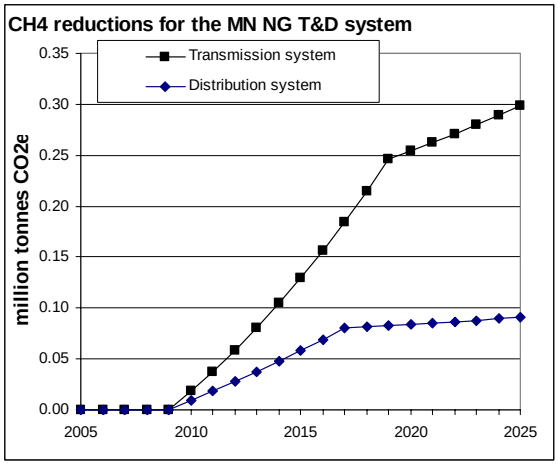
- Directed Inspection and Maintenance at Compressor Stations
- Reducing methane emissions from compressor rod packing systems
- Replacing wet seals with dry seals in centrifugal compressors

- Directed Inspection and maintenance at gate stations and surface facilities
- Convert engine starting to nitrogen
- Retrofit pneumatic devices with low-bleed kits
- Using pipeline pump-down techniques to lower gas line pressure before maintenance

For the MN natural gas distribution system, there were one mitigation option analyzed for its impact on reducing methane leaks, as follows:

- Directed Inspection and maintenance at gate stations and surface facilities

Regarding CO2-equivalent (CO2e) emissions reductions, the impact of the collective options is summarized in the chart below. The curves represents the annual CO2e reductions associated with avoiding methane leaks in the MN natural gas pipeline system. The annual emission reductions in 2015 and 2025 are 0.2 and 0.4 million tonnes CO2e, respectively. The cumulative emission reductions over the 2005-2025 forecast period are 3.9 million tonnes CO2e.



Regarding the annual costs of the option, there are incremental costs from biomass associated with capital improvements, O&M, and fuel for each of the options considered. There are incremental savings associated with the value of the natural gas emissions avoided. The net present value of these annual costs are $0.047 billion over the 2010-2025 period (2005$).

Regarding the cost effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, -$13/MWh (2005$) (i.e., 0.047 billion divided by 3.9 million tonnes and multiplied by a conversion factor of 1,000).

> *Note: I noticed that the formula I used to sum the total incremental costs of the options did not include all the options. This gives an deflated estimate of the cost savings since the incremental costs for the options are negative. After correcting, the results for costs and cost-effectiveness after this correction are -$.093 billion over the 2013-2025 period (2005$) and -$26/MWh (2005$).*

ES-5: Renewable and/or Environmental Portfolio Standard

As described in the TWG's policy option description, this option is a policy to require that utilities and other load-serving entities must supply a certain, generally fixed, percentage of electricity from eligible (e.g., low GHG emitting) renewable energy sources. The current MN

statue – 25% renewable energy as a percentage of sales – was modeled. For a numerical summary, see the ES-5 tab in spreadsheet called "MN ES results through 2025.xls" sent on 7 January 2008.

The TWG has made the following key assumptions for the analysis of this option, as follows:

- The start year for the option is 2011.
- Incremental renewable energy generation in MN would not displace generation from any resource in MN.
- Incremental renewable energy generation in MN would first displace NG-fired generation (combustion turbines) associated with imports and then coal-fired generation from imports.
- The costs associated with displaced generation would be energy-related only (i.e., fixed O&M, variable O&M, and fuel) and not include capacity-related costs.

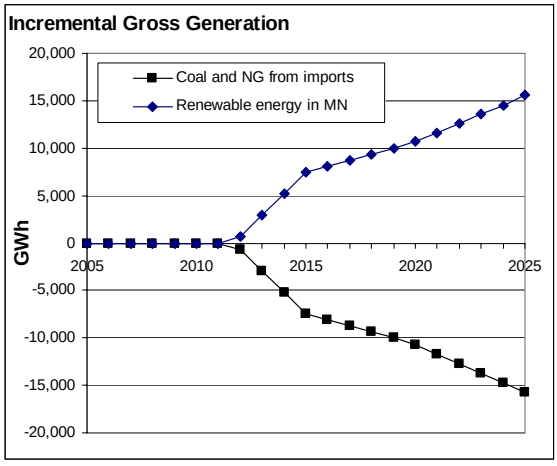
The TWG decided to assess the option under the following scenarios:

- Reference Scenario #1: All planned capacity additions; without the recently passed RES, and with the CIP legislation
- Reference Scenario #2: All planned capacity additions; with the recently passed RES and CIP legislation
- Reference Scenario #3: All planned capacity additions except for large coal additions; with the recently passed RES and CIP legislation

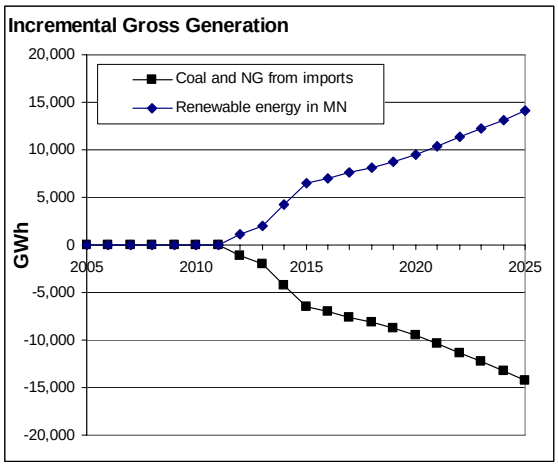
Broadly, the effect of implementing the assumptions is briefly summarized below for each of the scenarios analyzed:

- Difference between Reference Scenario #1 and Reference Scenario #2: substantial GHG reductions at net negative cost;
- Difference between Reference Scenario #1 and Reference Scenario #3: substantial GHG reductions at small net positive cost.

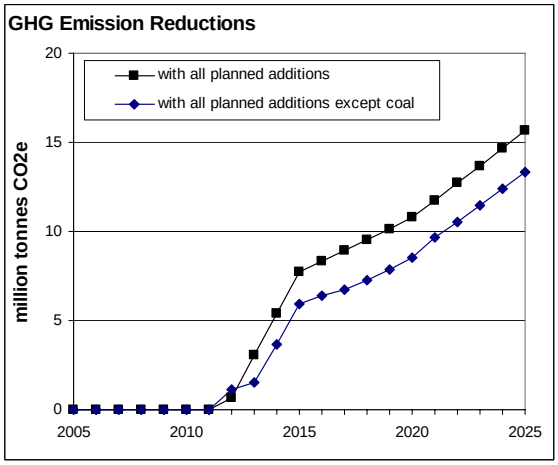
Regarding generation assuming all planned additions (i.e., difference between Reference Scenario #1 and Reference Scenario #2), the impact of the option is summarized in the chart below. The upper curve represents the total incremental generation associated with the RES in MN and the lower curve represents incremental displaced coal/NG-fired generation outside MN.



Regarding generation assuming all planned additions except large coal additions (i.e., difference between Reference Scenario #1 and Reference Scenario #3), the impact of the option is summarized in the chart below. The upper curve represents the total incremental generation associated with the RES in MN and the lower curve represents incremental displaced coal/NG-fired generation outside MN.



Regarding CO2-equivalent (CO2e) emission reductions, the impact of the option is summarized in the chart below. The upper curve represents the annual CO2e reductions associated with the RES assuming all planned additions. The lower curve represents the annual CO2e reductions associated with the RES assuming all planned additions except large coal. For the upper curve, the annual emission reductions in 2015 and 2025 are 7.7 and 15.7 million tonnes CO2e, respectively. The cumulative emission reductions over the 2005-2025 forecast period are 133.1 million tonnes CO2e.



Regarding costs, there are cost savings associated with avoided fuel and O&M at coal- and natural gas-fired facilities located outside MN. The levelized capital costs for a imported coal-fired and NG-fired was assumed to be $40/MWh and $185/MWh, respectively (2005$, see yesterday's memo). There are incremental costs associated with capital costs, transmission costs, variable O&M costs, fixed O&M costs and fuel costs associated with the expansion plans incorporating the RES. The avoided costs for Reference Scenarios #1, #2, and #3 were computed as $187/MWh, $163/MWh, and $166/MWh (2005$, see yesterday's memo). The incremental

costs for new renewable generation in MN was estimated as the difference in avoided costs (i.e., -$24/MWh for the difference between Reference Scenario #1 and Reference Scenario #2 and -$21/MWh for the difference between Reference Scenario #1 and Reference Scenario #3). The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. The net present value of these annual costs are -$1.7 billion over the 2011-2025 period (2005$).

Regarding the cost effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, -$12.6/MWh (2005$) (i.e., -1.7 billion divided by 133.1 million tonnes and multiplied by a conversion factor of 1,000).

> *Note: I only report the cost results for Reference Scenario #1 in the discussion above. The results for Reference Scenario #2 have not been included in the summary provided to the CCAG for their 7th meeting on 10 January 2008.*

ES-6: Nuclear Power Support and Incentives

As described in the TWG's policy option description, this option would provide support and incentives for life extension at existing nuclear power plants and for study of potential new nuclear power plants in Minnesota. It has been modeled thus far as a new nuclear power station in MN. For a numerical summary, see the ES-6 tab in spreadsheet called "MN ES results through 2025.xls" sent on 7 January 2008.

The TWG has made the following key assumptions for the analysis of this option, as follows:

- The start year for the option is 2020.
- Upstream fuel cycle GHG emissions should be accounted for.
- Size of the station is 1,100 MW.

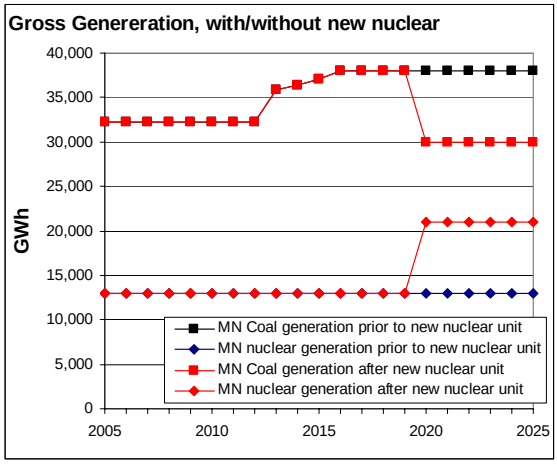
The TWG decided to assess the option under the following scenarios:

- Reference Scenario #1: All planned capacity additions; with the recently passed RES and CIP legislation
- Reference Scenario #2: All planned capacity additions except for large coal additions; with the recently passed RES and CIP legislation
- The displaced resource is existing coal power generated in MN.

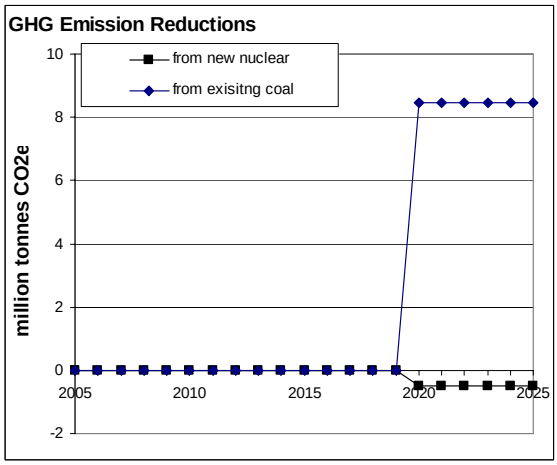
Broadly, the effect of implementing the assumptions is briefly summarized below for each of the scenarios analyzed:

- Reference Scenario #1: substantial GHG reductions at net positive cost;
- Reference Scenario #2: substantial GHG reductions at net positive cost.

Regarding generation, the impact of the option is summarized in the chart below for both Reference Scenarios. The upper curve represents the total MN coal generation before and after the introduction of the new nuclear station. The lower curve represents the total MN nuclear generation before and after the introduction of the new nuclear station.



Regarding CO2-equivalent (CO2e) emission reductions, the impact of the option is summarized in the chart below. The upper curve represents the annual CO2e reductions associated with backed down generation from existing coal-fired power stations in MN. The lower curve represents the annual CO2e reductions associated with increased generation from the new nuclear power station in MN. The net annual emission reductions in 2015 and 2025 are 0.0 and 8.0 million tonnes CO2e, respectively. The cumulative emission reductions over the 2005-2025 forecast period are 47.8 million tonnes CO2e.



Regarding costs, there are cost savings associated with avoided fuel and O&M at existing coal-fired facilities located in MN (i.e., $39/MWh after deducting the capital cost component in 2005$, see yesterday's memo). There are incremental costs associated with new nuclear capital costs, transmission costs, variable O&M costs, fixed O&M costs and fuel costs (i.e., $164/MWh in 2005$, see yesterday's memo) and then escalated to 2020 using the TWG escalation assumptions (see yesterday's memo). The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. The net present value of these annual costs are $3.3 billion over the 2020-2025 period (2005$).

Regarding the cost effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, $69.5/MWh (2005$) (i.e., 3.3 billion divided by 47.8 million tonnes and multiplied by a conversion factor of 1,000).

Note: I only report the cost results for Reference Scenario #1 in the discussion above. The results for Reference Scenario #2 have not been included in the summary provided to the CCAG for their 7th meeting on 10 January 2008.

ES-7: Advanced Fossil Fuel Technology Incentives, Support or Requirements

As described in the TWG's policy option description, this option would explore the role that coal could play in Minnesota's future energy system, providing its overall environmental profile improves and comes close to producing zero CO_2 emissions, while producing energy that is both affordable and reliable. It has been modeled thus far as an IGCC unit without carbon and storage. For a numerical summary, see the ES-7 tab in spreadsheet called "MN ES results through 2025.xls" sent on 7 January 2008.

The TWG has made the following key assumptions for the analysis of this option, as follows:

- The start year for the option is 2013.
- Size of the station is 600 MW.
- The resource displaced by the new IGCC plant is natural gas-fired generation from combustion turbines (note that this last assumption has not yet been discussed and vetted by the TWG)

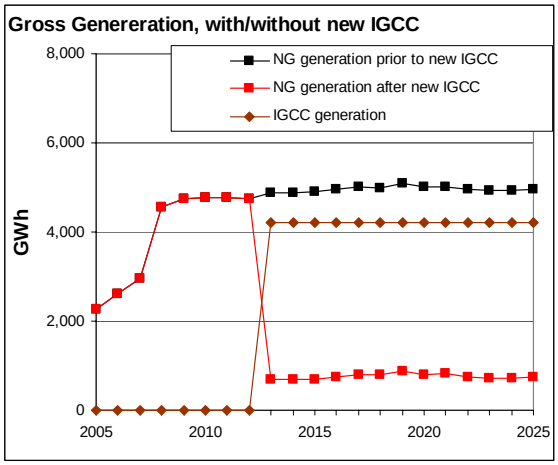
The TWG decided to assess the option under the following scenarios:

- Reference Scenario #1: All planned capacity additions; with the recently passed RES and CIP legislation
- Reference Scenario #2: All planned capacity additions except for large coal additions; with the recently passed RES and CIP legislation
- The displaced resource is existing coal power generated in MN.

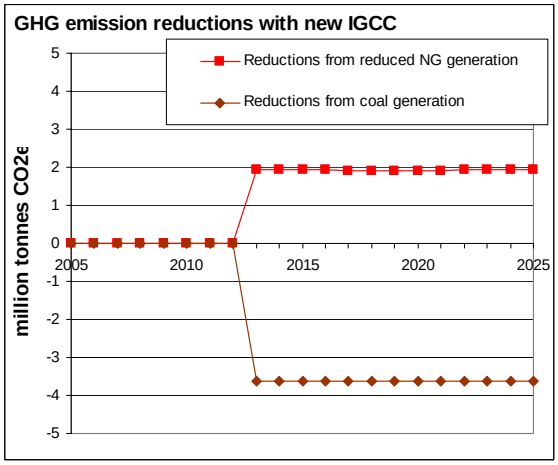
Broadly, the effect of implementing the assumptions is briefly summarized below for each of the scenarios analyzed:

- Reference Scenario #1: substantial increase in GHG emissions at net positive cost;
- Reference Scenario #2: substantial increase in GHG emissions at net positive cost.

Regarding generation, the impact of the option is summarized in the chart below for both Reference Scenarios.



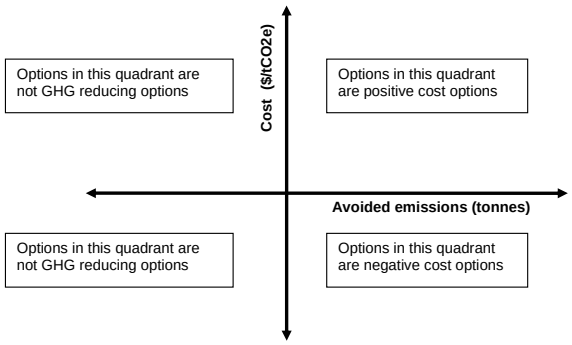
Regarding CO2-equivalent (CO2e) emission reductions, the impact of the option is summarized in the chart below. The upper curve represents the annual CO2e reductions associated with backed down generation from natural gas-fired power stations in MN and outside MN. The lower curve represents the annual CO2e emission increases associated with the generation from the new IGCC power station in MN. The net annual emission reductions in 2015 and 2025 are -1.7 and -1.7 million tonnes CO2e, respectively (note negative numbers indicate emission increases). The cumulative emission reductions over the 2005-2025 forecast period are -22.2 million tonnes CO2e.



Regarding costs, there are cost savings associated with avoided fuel and O&M at existing natural gas-fired facilities (combustion turbines) located in MN and outside MN (i.e., $185/MWh after deducting the capital cost component in 2005$, see yesterday's memo). There are incremental costs associated with new IGCC capital costs, transmission costs, variable O&M costs, fixed O&M costs and fuel costs (i.e., $129/MWh in 2005$, see yesterday's memo) and then escalated to 2020 using the TWG escalation assumptions (see yesterday's memo). The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. The net present value of these annual costs are $3.6 billion over the 2013-2025 period (2005$).

Regarding the cost effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, -$161.7/MWh (2005$) (i.e., 3.6 billion divided by -22.2 million tonnes and multiplied by a conversion factor of 1,000). Note that the negative cost

effectiveness value does not indicate that this is a negative cost option, as per the simple illustration below:



Note: I noticed that I used the levelized costs for a pulverized coal plant when calculating the cost savings associated with natural gas (error in linking to the proper cell in the spreadsheet). This gives a deflated estimate of the cost savings. After correcting, the results for costs and cost-effectiveness are -$1.0 billion over the 2013-2025 period (2005$) and $43/MWh (2005$). Note also that I only report the cost results for Reference Scenario #1 in the discussion above. The results for Reference Scenario #2 are identical.

ES-8: Carbon Capture and Storage and/or Reuse Policies

As described in the TWG's policy option description, this option would explore the role that coal could play in Minnesota's future energy system, providing its overall environmental profile improves and comes close to producing zero CO_2 emissions, while producing energy that is both affordable and reliable. It has been modeled thus far as an IGCC unit with carbon and storage. For a numerical summary, see the ES-8 tab in spreadsheet called "MN ES results through 2025.xls" sent on 7 January 2008.

The TWG has made the following key assumptions for the analysis of this option, as follows:

- The start year for the option is 2013.
- Size of the station is 600 MW.
- The efficiency of carbon capture was assumed to be 86% and the efficiency penalty was assumed to be 1,764 btu/kWh.
- The resource displaced by the new IGCC plant is natural gas-fired generation from combustion turbines (note that this last assumption has not yet been discussed and vetted by the TWG)

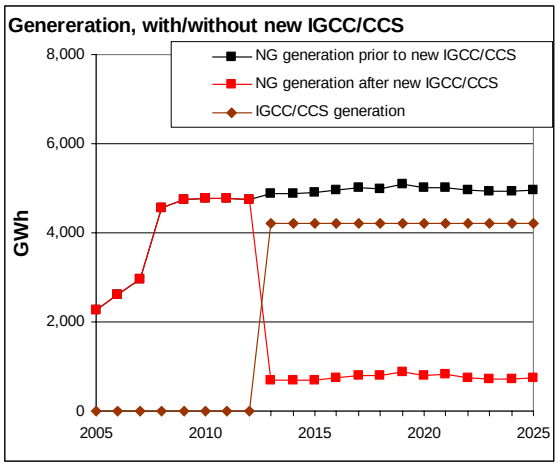
The TWG decided to assess the option under the following scenarios:

- Reference Scenario #1: All planned capacity additions; with the recently passed RES and CIP legislation
- Reference Scenario #2: All planned capacity additions except for large coal additions; with the recently passed RES and CIP legislation
- The displaced resource is existing coal power generated in MN.

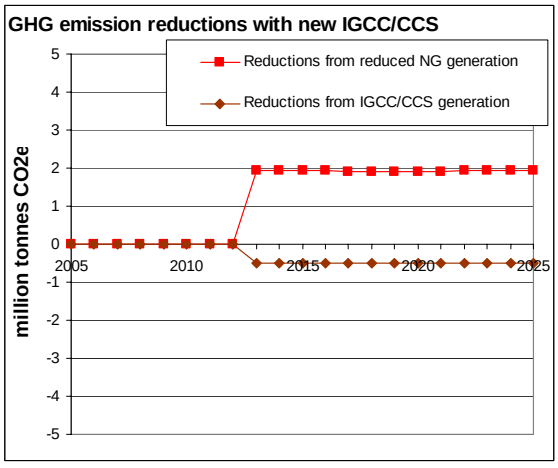
Broadly, the effect of implementing the assumptions is briefly summarized below for each of the scenarios analyzed:

- Reference Scenario #1: substantial decrease in GHG emissions at net positive cost;
- Reference Scenario #2: substantial decrease in GHG emissions at net positive cost.

Regarding generation, the impact of the option is summarized in the chart below for both Reference Scenarios.



Regarding CO2-equivalent (CO2e) emission reductions, the impact of the option is summarized in the chart below. The upper curve represents the annual CO2e reductions associated with backed down generation from natural gas-fired power stations in MN and outside MN. The lower curve represents the annual CO2e emission increases associated with the generation from the new IGCC power station in MN. The net annual emission reductions in 2015 and 2025 are 1.4 and 1.4 million tonnes CO2e, respectively. The cumulative emission reductions over the 2005-2025 forecast period are 18.4 million tonnes CO2e.



Regarding costs, there are cost savings associated with avoided fuel and O&M at existing natural gas-fired facilities (combustion turbines) located in MN and outside MN (i.e., $185/MWh after deducting the capital cost component in 2005$, see yesterday's memo). There are incremental costs associated with new IGCC/CCS capital costs, transmission costs, variable O&M costs, fixed O&M costs and fuel costs (i.e., $146/MWh in 2005$, see midpoint value in yesterday's

memo) and then escalated to 2020 using the TWG escalation assumptions (see yesterday's memo). The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. The net present value of these annual costs are $1.5 billion over the 2013-2025 period (2005$).

Regarding the cost effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, $83.6/MWh (2005$) (i.e., 3.3 billion divided by 18.4 million tonnes and multiplied by a conversion factor of 1,000). Note that the negative cost effectiveness value does not indicate that this is a negative cost option, as per the simple illustration below:

> *Note: I only report the cost results for Reference Scenario #1 in the discussion above. The results for Reference Scenario #2 have not been included in the summary provided to the CCAG for their 7th meeting on 10 January 2008.*