Energy Supply
Technical Work Group

Summary List of Pending Priority Policy Options for Analysis

	Policy Option	GHG Reductions ($MMtCO_2e$)			Net Present Value 2008–2025 (Million $)	Cost-Effectiveness ($/tCO_2e$)	Level of Support
		2015	2025	Total (2008–2025)			
ES-3	Efficiency Improvements, Repowering and other Upgrades to Existing Plants						
	Biomass co-firing	**0.2**	**0.4**	**4.2**	**$48**	**$12**	**Approved**
	Natural gas repowering	2.3	2.3	29.9	$3,599	$120	Approved

Notes:

1. ES TWG recommendations in **bold** above.

2. All option total are relative to the underlying assumption that electric expansion in MN proceeds with the recently legislated Conservation Improvement Program, Renewable Energy Standard and all planned additions including the Mesaba and Big Stone 2 stations.

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

Policy Description

This policy 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. This policy would complement a Generation Performance Standard (which applies to new plants and new units) by applying to existing units. Given that CO_2 emissions have not previously been the focus of state regulation, and given that existing units have not been the focus of resource planning, it is expected that there are as-yet unidentified opportunities to reduce emissions from existing facilities that will be cost-effective, particularly once CO_2 limits are in place. This policy would, in time, result in the identification of a portfolio of technological options for reducing GHG emissions and allow state utilities to share the opportunities they have identified.

CCS should investigate the impact of policies that

- Require utilities to evaluate their existing generating units for opportunities to improve their emissions profile through efficiency improvements, the addition of biomass or other fuel changes, or the addition of carbon capture technology. This evaluation would be part of an overall plan identifying cost-effective options for reducing system CO_2 emissions on a short-term and long-term basis.
- Require utilities to pursue cost-effective options for reducing their emissions profile through measure identified above.
- Create financial incentives that reward such emissions reductions.

The terms “cost-effective” would be defined by some objective measure, such as cost per ton of carbon equivalent.

Policy Design

Goals: The policy would be intended to ensure that utilities undertake analyses of their operating systems to identify and pursue cost-effective opportunities to reduce emissions.

Timing: This policy would become applicable as soon as possible.

Parties Involved: It would cover Minnesota load-serving entities.

Implementation Mechanisms

The planning and emission reduction requirements would be implemented through the Integrated Resource Planning (IRP) process already implemented by the Public Utilities Commission.

Related Policies/Programs in Place

Existing IRP requirements (see above). The requirement is an important counterpart to a Generation Performance Standard (GPS), which only covers new financial commitments. It complements a cap-and-trade policy by ensuring that utilities pursue cost-effective potential

emission reductions rather than the more obvious option of purchasing emission allowances (with the projected price of allowances being a key part of the definition of "cost effective" reductions).

Type(s) of GHG Reductions

Avoided emissions from fossil-fuel generation.

Estimated GHG Reductions and Net Costs or Cost Savings

- Energy Information Administration, "Assumptions to the Annual Energy Outlook 2007," DOE/EIA-0554, April 2007, available at: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf)
- National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants," DOE/NETL-2007/1281, August 2007, available at: http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf
- Plant-specific Minnesota capacity addition data are based on Form EIA-906, available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html

Quantification Methods:

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 as a biomass co-firing option with a sensitivity analysis on a natural gas repowering component.

Primary Analysis: biomass co-firing at MN coal stations:

The ES TWG has made the following key assumptions for the analysis of the biomass co-firing option, as follows:

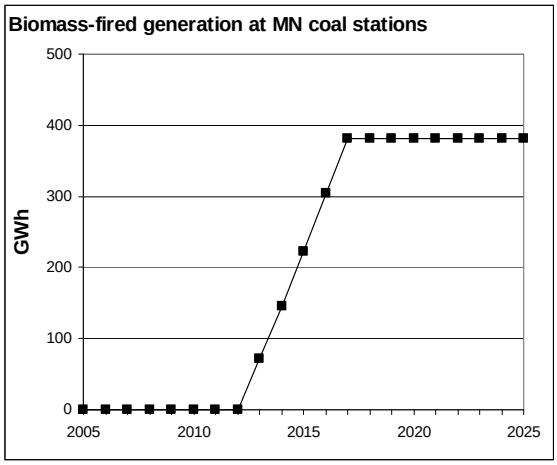
- The start year for the option is 2013.
- Biomass, harvested sustainably, represents a maximum of 1% of fuel combusted annually at pulverized coal power stations.
- The ramp-up period for full utilization of biomass in co-fired coal stations is 5 years.
- Woodwastes and forest residues are the major 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

Sensitivity Analysis: Natural gas repowering of an existing 600 MW coal station in MN

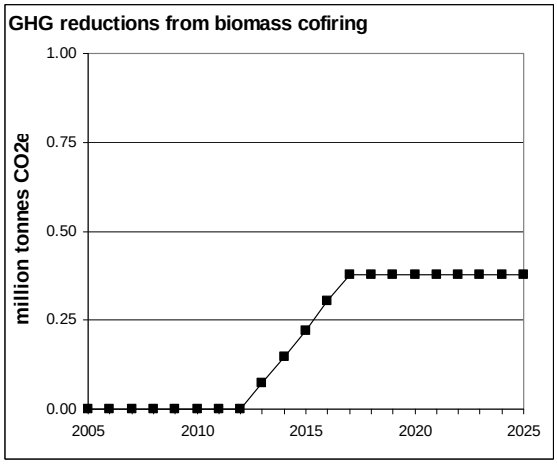
The ES TWG has made the following key assumptions for the analysis of the biomass co-firing option, as follows:

- The start year for the option is 2013.
- The coal station would be repowered with a natural gas combined cycle unit.

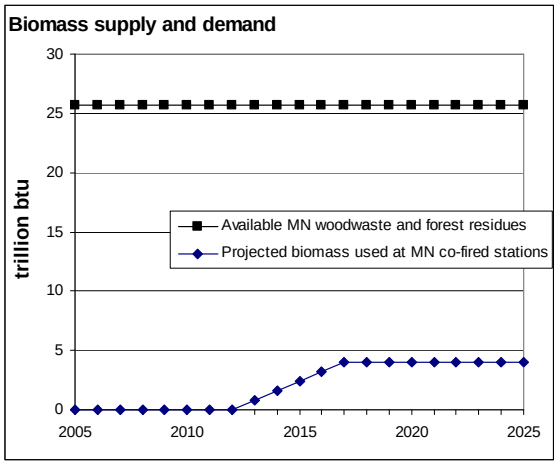
Regarding generation, the impact of the option is summarized in the chart below representing the total generation associated with co-fired biomass in MN.



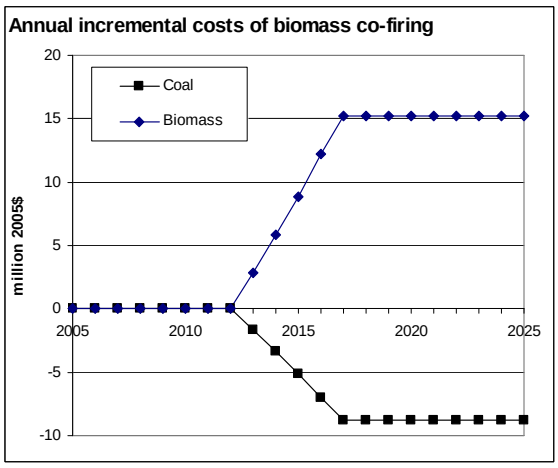
Regarding CO2-equivalent (CO2e) emission reductions, the impact of the option is summarized in the chart below representing the annual CO2e reductions associated with biomass co-firing. The annual emission reductions in 2015 and 2025 are 0.2 and 0.4 million tonnes CO2e, respectively. The cumulative emission reductions over the 2005-2025 forecast period are 4.2 million tonnes CO2e.



Regarding the demand/supply situation for woodwastes and forest residues, the impact of the option is summarized in the chart below. The projected biomass used at MN coal stations would not exceed available MN supply in any year.



Regarding the annual costs of the option, there are incremental costs from biomass associated with 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 $0.05 billion over the 2013-2025 period (2005$).



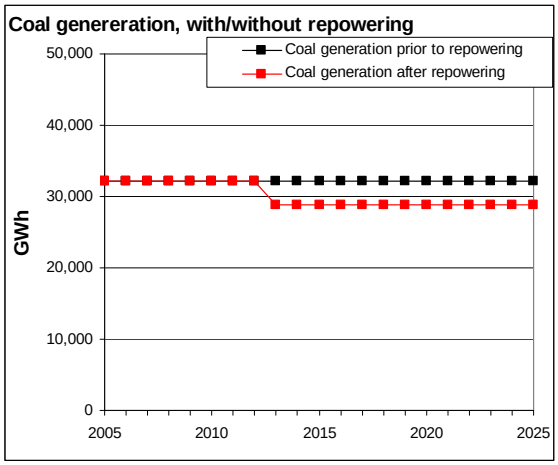
Regarding the cost effectiveness of the option, it was calculated for Reference Scenario #1 as the quotient of the NPV and cumulative GHG emission reductions, $12/tCO2e (2005$) (i.e., 0.05 billion divided by 4.2 million tonnes and multiplied by a conversion factor of 1,000).

Sensitivity Analysis: Natural gas repowering of an existing 600 MW coal station in MN

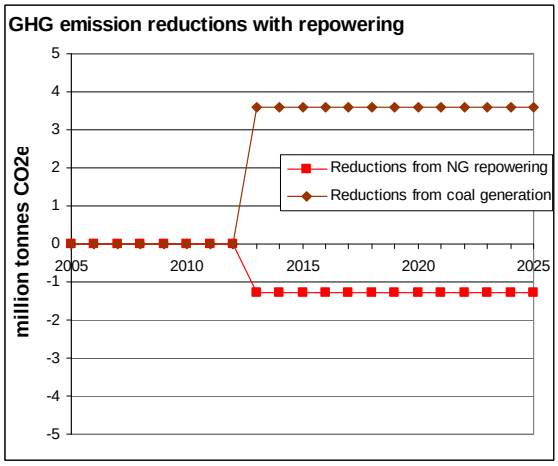
The ES TWG has made the following key assumptions for the analysis of the biomass co-firing option, as follows:

- The start year for the option is 2013.
- The coal station would be repowered with a natural gas combined cycle unit (NGCC).

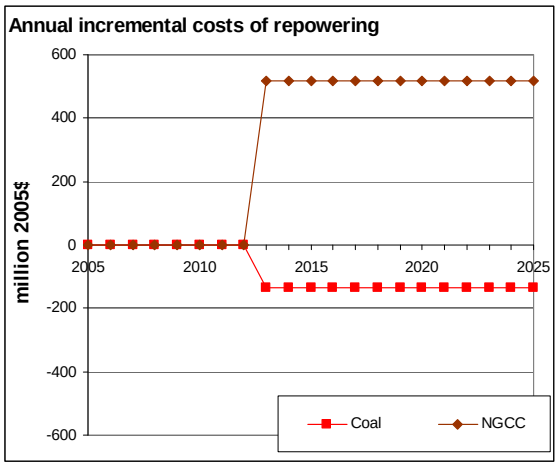
Regarding generation, the impact of the option is summarized in the chart below representing the total generation associated with existing coal stations, with and without the repowered facility in MN.



Regarding CO2-equivalent (CO2e) emission reductions, the impact of the option is summarized in the chart below representing the annual CO2e reductions associated with displaced coal generation and the incremental natural gas-fired generation. The net annual emission reductions are 2.3 million tonnes CO2e in 2015 and 2025. The net cumulative emission reductions over the 2013-2025 forecast period are 29.9 million tonnes CO2e.



Regarding the annual costs of the option, there are incremental capital, O&M, and fuel costs from the NGCC unit and incremental fuel and O&M savings from coal, as summarized in the chart below. The coal station was assumed to be fully depreciated. 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 for Reference Scenario #1 as the quotient of the NPV and cumulative GHG emission reductions, $120/tCO2e (2005$) (i.e., $3.6 billion divided by 29.9 million tonnes and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 2

Key Uncertainties

The Technical Working Group identified the following uncertainties: 1) whether and how the new source review provisions of the Clean Air Act would affect the promotion of plant upgrades; 2) how this option relates to the GPS proposal; 3) how the terms "cost-effective" should be defined; and 4) how it relates to the cap-and-trade proposals.

Additional Benefits and Costs

Reduced air pollution associated with displaced coal generation

Feasibility Issues

There are technical feasibility issues regarding the degree to which biomass co-firing would lead to the risk of wear, corrosion, slagging and fouling in the combustion system.

Status of Group Approval

Pending—[until MCCAG moves to final agreement at meeting #8]

Level of Group Support

TBD—[blank until MCCAG meeting #8]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

ES-3. Efficiency Improvements, Repowering and Other Upgrades to Existing Plants

➢ Primary Analysis: biomass co-firing at MN coal stations:

Start year for option 2013

Biomass co-firing assumption

2

1 Biomass represents 8% of fuel combusted annually at pulverized coal power stations (default)
2 User-defined (Biomass represents 1% of fuel combusted at pulverized coal power stations)

Ramp-up period for full utilization of biomass (years)

1

1 Policy ramps up linearly over a 5 year period (default)
2 User-defined (Policy ramps up linearly over a 10 year period)

Phase-in for co-firing portion

Start year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2008				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2009					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011							0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012								0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013									0.20%	0.40%	0.60%	0.80%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
2014										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016												0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2017													0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2018														0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2019															0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2020																0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2021																	0.00%	0.00%	0.00%	0.00%	0.00%
2022																		0.00%	0.00%	0.00%	0.00%
2023																			0.00%	0.00%	0.00%
2024																				0.00%	0.00%
2025																					0.00%
	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.20%	0.40%	0.60%	0.80%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%

Estimated MN levelized costs (2005$/MWh) - All Scenarios

Capacity type	Capacity	ansmiss	ixed O&	riable O&	Fuel	Total
Pulverized coal	68.8	2.3	5.9	8.5	23.1	108.7
Biomass co-firing	0.0	0.0	0.0	0.0	40.0	40.0

➢ Sensitivity Analysis: Natural gas repowering of an existing 600 MW coal station in MN

Number of NGCC repowered coal stations units 1

Online year for NGCC repowered coal stations unit(s) 2013

Characteristics of power stations

	Units	NGCC	Coal
Size	MW	600	600
Capacity factor	%	65%	65%
Heat rate	btu/kWh	6,990	10,949
Annual gross generation	GWh/yr	3,416	3,416
CO2e emission factor	tCO2e/mmbtu	0.0539	0.0959
CO2e emission factor	E6 tCO2e/GWh	0.0004	0.0011

Levelized cost assumptions (2005$/MWh)

	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total
Pulverized coal	0.0	2.3	5.9	8.5	23.1	39.9
NGCC	40.9	3.1	3.0	2.3	102.7	152.0