MINNESOTA Climate Change Advisory Group

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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 $)	Cost-Effective-ness ($/t$CO_2e$)	Level of Support
		2015	2025	Total (2008–2025)			
ES-1	Generation Performance Standard						
	Reference Scenario #1	3.88	4.56	56.12	$671	$12.0	Pending
	Reference Scenario #2	3.88	4.56	56.12	$671	$12.0	Pending
	Reference Scenario #3	0.64	0.62	8.24	$114	$13.9	Pending
ES-3	Efficiency Improvements, Repowering and other Upgrades to Existing Plants						
	Reference Scenario #1	1.50	2.69	28.52	$159	$5.59	Pending
	Reference Scenario #2	1.23	1.87	21.84	$123	$5.65	Pending
	Reference Scenario #3	1.27	1.93	22.56	$122	$5.41	Pending
ES-4	Transmission System Upgrading, Including Reducing Transmission Line and Distribution System Loss	*Not quantified*					Pending
ES-5	Renewable and/or Environmental Portfolio Standard						
	With coal additions	6.20	12.47	109.28	$2,084	$19.1	Pending
	No coal additions	6.40	12.83	112.68	$2,270	$20.1	Pending
ES-6	Nuclear Power Support and Incentives	*Not quantified*					Pending
ES-7	Advanced Fossil Fuel Technology Incentives, Support or Requirements	0.8	0.8	10.2	$1,085	$106.2	Pending
ES-8	Carbon Capture and Storage and/or Reuse Policies	3.8	3.8	49.5	$3,767	$76.1	Pending
ES-10	Voluntary GHG targets	*Not quantified*					Pending
ES-12	Distributed Renewable Energy Incentives and/or Barrier Removal	*Still being quantified*					Pending
ES-13	Technology-Based Approaches, Including Research and Development, Fuel Cells, Energy Storage, Distributed Renewable Energy Technologies, etc.	*Not quantified*					Pending
	Sector Total After Adjusting for Overlaps	**14.6**	**22.3**	**231**	**TBD**	**TBD**	
	Reductions From Recent Actions	**6.9**	**6.9**	**123**	**TBD**	**TBD**	
	Sector Total Plus Recent Actions	**21.5**	**29.2**	**354**	**TBD**	**TBD**	

Notes: During its September 27, 2007 meeting, the MCCAG agreed to move ES-2 (Improve the GHG Profile of Biofuels and Fossil Fuels [e.g., Low Carbon Fuel Standard, Biofuel Production]) to the TLU TWG which is now being addressed under TLU-3 (Low GHG Fuel Standard).

ES-1. Generation Performance Standard

Policy Description

A generation performance standard (GPS) is a mandate that requires those entities that deliver electricity (load-serving entities [LSEs]) 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.

Policy Design

Goals: The general goal of the policy is to prevent utilities from making long-term investments in high-carbon generation technology. In particular, the generation performance standard would prevent utilities from making a long-term financial commitment to base load generation plants with CO_2 emissions in excess of 1,100 pounds of CO_2 per megawatt-hour.

A long-term financial commitment would be defined to include either a new ownership investment in base load generation or a new contract with a term of five or more years, which includes procurement of base load generation. The TWG would like CCS to analyze the impact of two different approaches regarding the renewal of contracts procuring base load power from existing units—one approach that includes such contracts (if they are for five or more years) and one that excludes them.

The GPS would be designed to harmonize with policies that seek to reduce greenhouse gas (GHG) emissions by promoting greater use of biomass and combined heat and power (CHP). For purposes of compliance with the GPS, the CO_2 emissions attributed to biomass energy would be net emissions based on a full fuel-cycle analysis. For base load projects that are part of a CHP project, the GPS would be raised to 1300 pounds of CO_2/MWh.

Timing: CCS should analyze two alternative onset dates for the GPS—an immediate onset data that would apply to all base load projects not already in operation, and a delayed onset date that would exclude base load facilities currently under consideration in proceedings before the Public Utilities Commission. The ongoing need for a GPS would be reviewed after the implementation of a cap-and-trade system.

Parties Involved: The program would apply to any state LSE making long-term financial commitments to base load power.

Implementation Mechanisms

Implementation would be through the Public Utilities Commission, which would review all long-term financial commitments to base load generation made by Minnesota utilities to ensure compliance with the generation performance standard.

Related Policies/Programs in Place

None.

Type(s) of GHG Reductions

Reduces carbon dioxide emissions from fossil-fuel electric generators, and promotes low carbon alternatives to fossil fuel generators.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources: The following data sources were used in the analysis of this mitigation option:

- 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: See Annex 1

Key Assumptions: See Annex 2

Key Uncertainties

The GPS would expand PUC oversight to certain transactions or projects not currently subject to PUC review under the Certificate of Need or other laws, but only for the purpose of screening those transactions or projects for compliance with the GPS. It is uncertain how many additional projects would be subject to PUC approval. It is expected that the GPS approval process would be far more streamlined than the typical Certificate of Need review process.

Other uncertainties noted by the Technical Working Group include a) the need to consider whether a GPS is necessary if the state enacts a cap-and-trade program covering electric generation; b) whether the 1,300 pounds per megawatt hour threshold is set at the right level to encourage efficient CHP installations; c) whether natural gas peaker units could reasonably be included in the policy in addition to base load generation; and d) whether offsets would be allowed for compliance flexibility.

Additional Benefits and Costs

TBD—[as needed and approved by the TWGs]

Feasibility Issues

TBD—[as needed and approved by the TWGs]

Status of Group Approval

Pending—[until MCCAG moves to final agreement at meeting #6 or #7]

Level of Group Support

TBD—[blank until MCCAG meeting #6 or #7]

Barriers to Consensus

TBD – [blank until final vote by the MCCAG]

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: See Annex 1

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

TBD—[as needed and approved by the TWGs]

Feasibility Issues

TBD—[as needed and approved by the TWGs]

Status of Group Approval

Pending—[until MCCAG moves to final agreement at meeting #6 or #7]

Level of Group Support

TBD—[blank until MCCAG meeting #6 or #7]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

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

Policy Description

Measures to improve transmission systems to reduce bottlenecks and enhance throughput may be required to meet long-term electricity demands and improve the efficiency of operations system wide. Opportunities may exist to substantially increase transmission line carrying capacity through the implementation of new construction and retrofit activities on the transmission grid, including incorporating advanced composite conductor technologies, capacitance technologies, and grid management software.

Siting new transmission lines can be a difficult process due to the regulatory time and cost of line construction including new Right-of-Way (R/W) acquisition. This increases environmental impacts through increased carbon emissions due to siting and clearing a R/W and the local impact on the environment, habitat, and on land use, enjoyment, and value of property.

Policy measures in support of this option could provide incentives to utilities to upgrade transmission systems and reduce barriers to Certificate of Need filings for new and existing transmission lines. Future development of renewable energy facilities may require the addition of new or improved transmission lines which must be seamlessly integrated into the transmission grid. Measures facilitating development of these projects can be a critical part of Minnesota's renewable energy future.

There are several energy efficiency measures that can be implemented to reduce the transmission and distribution line losses of electricity. Utilities use a variety of components throughout the transmission and distribution system to manage losses. Increasing the efficiency of these components can further reduce losses and associated GHG emissions. For example, the state of Vermont offers a rebate to encourage the installation of energy efficient transformers. Regulations, incentives, and/or support programs can be applied to achieve greater efficiency of transmission and distribution system components.

Any reduction of leaks during production, processing, and distribution on natural gas systems avoids methane emissions to the atmosphere and prevents the waste of valuable product.

Policy Design

Goals:

- Provide financial incentives for implementing smart energy (computer) technologies.
- Assess the effectiveness of the streamlining efforts enacted in 2005 to siting and routing of transmission lines to determine what additional streamlining activities should be enacted.
- Allow financial recovery credit for related efficiency savings resulting in GHG reductions even if it is not shown to be cost effective from a customer standpoint whether it results from upgrading transformers or reconductoring (replacing inefficient conductors).

- Improve individual line and grid efficiencies with incentives to reduce line losses.
- Provide financial R&D support to identify new technologies including improved leak surveying of natural gas systems and upgrading natural gas controllers that operate and vent natural gas.

Timing: When should the program launch and over what time period should the reductions be achieved?

Parties Involved: Electric Utilities, Gas Utilities, Independent System Operator, Gas Pipeline Companies

Implementation Mechanisms

TBD

Related Policies/Programs in Place

Renewable energy objective, 25 by 2025.

Type(s) of GHG Reductions

Reduced carbon dioxide from fossil-fuel electricity generation; Avoided emissions from increased siting of renewable energy facilities; avoided methane emissions from leaks in natural gas distribution.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources: N/A

Quantification Methods: N/A

Key Assumptions: N/A

Key Uncertainties

The proposal would need to be integrated with the existing Cap-X 2020 program.

Additional Benefits and Costs

TBD—[as needed and approved by the TWGs]

Feasibility Issues

TBD—[as needed and approved by the TWGs]

Status of Group Approval

Pending—[until MCCAG moves to final agreement at meeting #6 or #7]

Level of Group Support

TBD—[blank until MCCAG meeting #6 or #7]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

ES-5. Renewable and/or Environmental Portfolio Standard

Policy Description

A portfolio standard policy can be designed to require that a sector (Electricity Supply, Transportation, Industrial/Manufacturing and Commercial/Residential buildings) provide for lower GHG emissions from energy use or operations by targeting an increased amount of lower emission activities in the aggregate by a target date. A renewable portfolio standard (RPS) is a requirement 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. An environmental portfolio standard (EPS) expands portfolio requirements to include energy production with technologies that are not now classified as renewable but are viewed as releasing less GHG emissions than conventional energy production. These can include energy efficiency improvements or other GHG emission-reducing technologies (such as combined heat-and-power [CHP]) as an eligible resource. About 20 states currently have an RPS in place, while a handful have implemented an EPS. In some cases, utilities can also meet their portfolio requirements by purchasing Renewable Energy Certificates from eligible renewable energy projects or carbon offsets from certified sources.

Minnesota has adopted a renewable energy objective of 25% by 2025.

Policy Design

Goals:

- Evaluate what GHG reductions may be realized should Minnesota increase portfolio requirements beyond the 2025 time frame requirement in existing law through 2050. The study should include an analysis of the adequacy of transmission capacity.
- Evaluate hydro, biomass and the use of offsets in the context of CO_2 benefits to meet RES/EPS requirements as defined in Minnesota State Statutes
- Increase R&D funding for renewable/environmental (low CO_2 emitting) energy that reduces CO_2/GHG emissions (e.g., U of M IREE)
- Evaluate Performance Standards (Carbon Intensity Target) for renewable/environmental energy use by Residential, Commercial and Industrial entities.

Timing: Assume that current legislation will cover the time period from current to 2025. Legislation should be enacted by 2009 to give time for planning to meet the new standards. Funding for Renewable/Environmental R&D should begin as soon as practicable.

Parties Involved: M-RETS, Minnesota Public Utilities Commission, Minnesota State Legislature, Minnesota Department of Commerce

Other?

Implementation Mechanisms

Requires future legislation covering period from 2025 to 2050 for the renewable requirement while:

- Performing an evaluation of expanding the RPS requirement once the dates in existing law have been reached.
- Providing utilities with adequate lead-time.
- Re-evaluating expansion of what qualifies as renewable and/or environmental sources.

Increase funding by 2009 for R&D relative to new and improved technology advancements.

Institute a renewable energy credit trading program. (Minnesota Statutes 2007, Chapter 216B.1691).

Explore creation of energy intensity targets like carbon intensity targets as a means for broadening the application of portfolio standards to all Minnesota sectors.

Related Policies/Programs in Place

The state has adopted a 25% renewable energy goal by 2025.

Minnesota Statutes 2007, Chapter 216

Type(s) of GHG Reductions

Reductions in all GHG emissions from energy production and GHG emissions associated with process operational emissions and energy consumption.

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 is based on Form EIA-906 (available at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html)
- Minnesota Next Generation Energy Bill; Article 5, Section 2, lines 41.2 and following

Quantification Methods: See Annex 1

Key Assumptions: See Annex 2

Key Uncertainties

TBD—[as needed and approved by the TWGs]

Additional Benefits and Costs

TBD—[as needed and approved by the TWGs]

Feasibility Issues

TBD—[as needed and approved by the TWGs]

Status of Group Approval

Pending—[until MCCAG moves to final agreement at meeting #6 or #7]

Level of Group Support

TBD—[blank until MCCAG meeting #6 or #7]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

ES-6. Nuclear Power Support and Incentives

Policy Description

The role of nuclear power in a GHG-constrained energy supply system is both important and controversial. Today, nuclear power plants provide about 20% of electric power both nationally and in Minnesota. The role of both existing and new units needs to be considered for a comprehensive climate change policy process.

This policy provides support and incentives for life extension at existing nuclear power plants and for study of potential new nuclear power plants in Minnesota.

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 with an emphasis on nuclear power through:

- Life extension,
- Capacity upgrades,
- Purchase of imported nuclear power, and
- Potential new nuclear power plants.

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

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

Implementation Mechanisms

The planning requirements would be implemented through the Integrated Resource Planning (IRP) process already implemented by the Public Utilities Commission. Thorough consideration of the safety, economics, and environmental implications of nuclear power would be explicitly called for.

In addition, the ongoing work at the Minnesota Legislature periodically produces reports and positions that enable a more comprehensive look at the issues surrounding nuclear power. These efforts would continue to inform the debate.

Related Policies/Programs in Place

Existing IRP requirements (see above). These require consideration of relatively low-value GHG adders in the planning process, but do not require specific analysis of nuclear power as a GHG-reducing supply option. In the event that a comprehensive GHG policy were implemented in the state's electric power sector, it would likely overlap with this policy, although it is likely that full consideration of nuclear power options could still require a dedicated policy.

Type(s) of GHG Reductions

Avoided emissions from fossil-fuel generation.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources: N/A

Quantification Methods: N/A

Key Assumptions: N/A

Key Uncertainties

- Nuclear fuel availability
- Nuclear waste storage and disposal
- Security requirements
- Changes in federal policy (e.g., Nuclear Regulatory Commission relicensing, long-term waste repository)
- Technology and economics of new units
- Industry-wide developments

Additional Benefits and Costs

TBD—[as needed and approved by the TWGs]

Feasibility Issues

Mostly captured in the Key Uncertainties items above. Political feasibility also affects nuclear power, to differing degrees for life extensions and capacity upgrades as opposed to new units.

Status of Group Approval

Pending—[until MCCAG moves to final agreement at meeting #6 or #7]

Level of Group Support

TBD—[blank until MCCAG meeting #6 or #7]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

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

Policy Description and Design

Goals: For coal to play a significant role in Minnesota's future energy system, its overall environmental profile must improve, and come as close as possible to producing zero CO_2 emissions, while producing energy that is both affordable and reliable.

Timing: By 2020, the Upper Midwest region (Minnesota, Wisconsin, North and South Dakota) should strive to have at least two IGCC projects with CCS through design, construction and into full operation. Similar goals for demonstrations of amine scrubbing, oxy-fuel combustion, and next generation gasification technologies should be developed.

Parties Involved: Incumbent utilities, IPPs, state regulators.

Implementation Mechanisms

- Technology demonstrations—Critical to have commercial scale demonstrations using low-rank coals designed and under construction within the next 5 years, including demonstrations of IGCC with western sub-bituminous coal, IGCC with North Dakota lignite, and IGCC in conjunction with renewable energy such as wind power and/or hydrogen production. There are three demonstrations already in progress: Excelsior Energy's Mesaba IGCC project proposed for northeastern Minnesota, Xcel Energy's proposed IGCC demo in Colorado, and Great River Energy's coal-to-liquids IGCC project with CCS in North Dakota.
- Provide support for Front-End Engineering and Design (FEED) packages—state programs that offset some of the cost of FEED packages would allow utilities and developers to recoup their initial engineering costs through state tax credits or grants.
- Provide direct stat financial incentives (tax credits, loan guarantees, etc.)
- Allow regulated utilities cost recovery for appropriate demonstration projects.
- Enhance IRP policies by using them to encourage low-CO_2 coal technologies—by incorporating proxy values for risk of future carbon regulations as Minnesota's 2007 legislation directs.
- Update workforce training and research and development programs and investments, with a focus on developing the gasification and carbon sequestration industries.

Related Policies/Programs in Place

In 2003 the Minnesota Legislature enacted two statues—Minnesota Stat. 216B.1693 (the "Clean Energy Technology Statue") and Minnesota Stat. 216B. 1694 (the Innovative Energy Project Statue")—providing important regulatory incentives, including an exemption from the requirements of a certificate of need and eminent domain rights for approved sites and routes for project facilities, to encourage the rapid development of IGCC projects in Minnesota.

Type(s) of GHG Reductions

Reductions in emissions of carbon dioxide from coal combustion.

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 is based on Form EIA-906, available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html

Quantification Methods: See Annex 1.

Key Assumptions: See Annex 2.

Key Uncertainties

TBD—[as needed and approved by the TWGs]

Additional Benefits and Costs

TBD—[as needed and approved by the TWGs]

Feasibility Issues

TBD—[as needed and approved by the TWGs]

Status of Group Approval

Pending—[until MCCAG moves to final agreement at meeting #6 or #7]

Level of Group Support

TBD—[blank until MCCAG meeting #6 or #7]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

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

Policy Description and Design

Goals: For coal to play a significant role in Minnesota's future energy system, its overall environmental profile must improve, and come as close as possible to producing zero CO_2 emissions, while producing energy that is both affordable and reliable.

Timing: By 2020, the Upper Midwest region (Minnesota, Wisconsin, North and South Dakota) should strive to have at least two IGCC projects with CCS through design, construction and into full operation. Similar goals for demonstrations of amine scrubbing, oxy-fuel combustion, and next generation gasification technologies should be developed.

Parties Involved: Incumbent utilities, IPPs, state regulators.

Implementation Mechanisms

Require development of the legal and regulatory frameworks needed for geologic storage of CO_2—new regulations should address issues of CO_2 ownership in storage and liability for same. State environmental agencies should develop permitting processes for underground storage, including guidance on pipelines, drilling, storage, measurement, monitoring and verification.

Support comprehensive assessments of geologic reservoirs at state and federal levels to determine storage potential and feasibility.

Evaluate the feasibility of CO_2 transport via pipeline and "advanced sequestration" (i.e., mineralization, carbon nanofibers) if Minnesota determines it has no in-state storage opportunities.

Provide tax incentives for CCS, including when transported via pipeline for use in enhanced oil recovery operations.

Related Policies/Programs in Place

None.

Type(s) of GHG Reductions

Reductions in emissions of carbon dioxide from combustion sources.

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
- Intergovernmental Panel on Climate Change (IPCC), "Carbon Capture and Storage," 2006.

Quantification Methods: See Annex 1.

Key Assumptions: See Annex 2.

Key Uncertainties

TBD

Feasibility Issues

TBD

Status of Group Approval

Pending—[until MCCAG moves to final agreement at meeting #6 or #7]

Level of Group Support

TBD—[blank until MCCAG meeting #6 or #7]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

ES-10. Voluntary GHG Targets

Policy Description

Numerous U.S. companies and organizations, including many utilities, have taken on voluntary GHG reduction commitments. Some of these are organized through the US EPA's Climate Leaders program. Others include participation in Power Partners and the EIA 1605(b) Voluntary GHG Emission Reduction Program. These commitments can be based on total GHG emissions in a given year, specific voluntary projects or can be defined on an intensity basis (tCO_2e per MWh generated or delivered.) Some entities with voluntary commitments also transact through the Chicago Climate Exchange (CCX), a self- regulating pilot program for reducing and trading GHG emissions in North America.

Policy Design

Goals: The goals for a Minnesota Voluntary GHG program include

- Encouraging Minnesota business and citizens to voluntarily begin reducing GHG emissions immediately, without waiting for mandatory Minnesota or national GHG reduction program measures.
- Providing a means for Minnesota voluntary GHG emission reductions to be quantified and recognized by applying Minnesota approved GHG quantification methods.
- Allowing regulated entities assurance of cost recovery for voluntary GHG reduction measures that are previewed and approved by the MPUC as in the best interest of Minnesota stakeholders, considering Minnesota climate change risks.
- Providing documentation that supports voluntary measures receiving full credit under a future Minnesota or national mandatory or voluntary GHG reduction program (e.g., credit for early action).
- Enabling Minnesota voluntary GHG emission reduction measures to receive credit as certifiable CO_2 offsets for use within and outside of the United States.

Timing: Upon promulgation.

Parties Involved: All sectors and sources that wish to provide for voluntary GHG reductions or offsets, including: government, industry, business, commercial building owners and homeowners.

Other?

Implementation Mechanisms

Legislation will provide for voluntary GHG emission reductions to be registered and for cost recovery mechanisms. The MPCA shall be authorized to provide for voluntary measure recordkeeping. The MPUC shall be authorized to provide for review for public interest for cost recovery.

Related Policies/Programs in Place

None.

Type(s) of GHG Reductions

Reductions in emissions of carbon dioxide, as well as other GHGs, depending on participation in the program.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources: N/A

Quantification Methods: N/A

Key Assumptions: N/A

Key Uncertainties

TBD—[as needed and approved by the TWGs]

Additional Benefits and Costs

TBD—[as needed and approved by the TWGs]

Feasibility Issues

TBD—[as needed and approved by the TWGs]

Status of Group Approval

Pending—[until MCCAG moves to final agreement at meeting #6 or #7]

Level of Group Support

TBD—[blank until MCCAG meeting #6 or #7]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

ES-12. Distributed Renewable Energy Incentives and/or Barrier Removal

Policy Description

Distributed renewable energy should be encouraged as it plays a part in the overall goal of reducing carbon emissions. This policy includes subsidies or incentives that encourage investment in small-scale distributed renewable energy resources.

Policy Design

Goals: The goal of this policy is to encourage investment small-scale distributed renewable energy via incentives and/or the prevention of barriers. Incentives for distributed renewables should include: (1) direct subsidies for purchasing/selling renewable technologies; (2) tax credits or exemptions for purchasing/selling renewable technologies; (3) feed-in tariffs, which provide direct payments to renewable generators for each kWh of electricity generated from a qualifying renewable facility (feed-in tariffs should take into consideration and recognize all the attributes of energy including carbon impact to the purchaser and the "green impact"); (4) tax credits for each kWh generated from a qualifying renewable facility; (5) allowing the distributed generation projects count toward the Conservation Improvement Program (CIP) savings goal of 1.5% annually if the investment is reasonable and prudent, whether utility-owned or customer-owned.

Timing: Analysis and review of technologies, financial incentives and size of a project to begin immediately

Parties Involved: All utilities serving customers in Minnesota; state agencies with jurisdiction; other interested stakeholders.

Other? A source to cover any financial incentive would need to be determined. The level of credit or funding should be consistent for all utilities (IOUs, municipals and cooperatives). The cost of the incentive should be shared among all end users so that no one is overly burdened.

Implementation Mechanisms

- Funding mechanisms and incentives
- Regulatory policies that support utility investments in small-scale distributed renewable energy.

Related Policies/Programs in Place

Renewable Energy Standard 25 × 25. Existing matching programs for investment in photovoltaic systems. Wind production tax credits.

Type(s) of GHG Reductions

Reductions in emissions of carbon dioxide from combustion sources.

Estimated GHG Reductions and Net Costs or Cost Savings

TBD.

Data Sources: [TBD by CCS on TWG approval]

Quantification Methods: [e.g., Full life cycle analysis with supply/demand equilibrium adjustments on TWG approval]

Key Assumptions: [TBD, as needed on TWG approval]

Key Uncertainties

TBD—[as needed and approved by the TWGs]

Additional Benefits and Costs

TBD—[as needed and approved by the TWGs]

Feasibility Issues

TBD—[as needed and approved by the TWGs]

Status of Group Approval

Pending—[until MCCAG moves to final agreement at meeting #6 or #7]

Level of Group Support

TBD—[blank until MCCAG meeting #6 or #7]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

ES-13. Technology-Based Approaches, Including Research and Development, Fuel Cells, Energy Storage, and Distributed Renewable Energy Technologies

Policy Description

Technology and innovation play a critical role in the development of economic processes, including energy production and use. Major progress in climate change policy requires improvements to technologies as well as increased rates of technology adoption and use. Trends toward smaller scale in energy production technology, combined with the impact of automation and remote system controls, present challenges to current business models and operational procedures.

This policy is an umbrella covering several technology-related policy options that together can contribute to GHG emission reductions in Minnesota.

Policy Design

Goals: This set of policies would provide state government and other private and public parties with resources and incentives for analysis, targeted R&D, market development, and adoption of GHG-reducing technologies that are not covered by other policies. The overall goals would be:

- To position Minnesota as a world leader in climate-related technology development and deployment,
- To achieve actual emission reductions from technology investments, and
- To develop state industries with high in-state and export capability.

Timing: This policy would be intended to come into effect in 2008 and 2009 and would continue indefinitely as an enabling mechanism for other climate-related policies.

Parties Involved: Minnesota government. Private and public partners on a voluntary basis.

Implementation Mechanisms

An R&D budget line item would be created to fund a small staff in the Commerce Department or another related agency. This group would follow technology trends and identify critical technology pathways as well as opportunities for collaboration and funding from other sources.

In addition, a Clean Technologies Innovation Program would be funded at the state level to provide grants and incentives as they are identified by the state along with other sources of public input into the prioritization process. Two models would be the California Public Interest Energy Research (PIER) program and the New York Energy Research and Development Agency (NYSERDA). Utilities would be able to apply as partners for these funds.

Finally, the state's regulated utilities would be allowed to devote a percentage of their sales revenue to substantial R&D projects on a voluntary basis as part of their overall energy supply portfolios. The invested capital portion of these projects would be given advantageous cost recovery as an incentive to carry out such projects. This policy could be relaxed when effective climate change policy comes into effect, although there may still be merit in continuing some level of incentive for utility R&D effort even when climate policy is in place.

These policies would replace the current, more limited Renewable Development Fund (RDF).

Related Policies/Programs in Place

State efforts on innovation, including biotechnology, agriculture, and transportation.

Renewable Development Fund.

Tax credits and Federal incentives.

Technology-specific policies such as hybrid vehicle or solar pilot programs and incentives.

Type(s) of GHG Reductions

Various, from no direct reductions to direct offset of emitting fuels, processes to actual uptake and use of GHGs thus removing them from the atmosphere.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources: N/A

Quantification Methods: N/A

Key Assumptions: N/A

Key Uncertainties

Funding level stability.

Ability to identify productive technology pathways.

Measures of success and program oversight.

Additional Benefits and Costs

TBD—[as needed and approved by the TWGs]

Feasibility Issues

Requires broad range of skills for effective administration.

Status of Group Approval

Pending—[until MCCAG moves to final agreement at meeting #6 or #7]

Level of Group Support

TBD—[blank until MCCAG meeting #6 or #7]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

Annex 1: Methodology for the Quantification of Energy Supply Mitigation Options

This Annex outlines key elements of the methodology used for quantifying the GHG reduction benefits and associated costs for energy supply policy options that are considered amenable to quantification. The list of topics addressed in this Annex is summarized below. Feedback from energy supply TWG members has been solicited in the finalization of this methodological approach.

- Premises
- Outputs
- Methodology
- Assumptions
- Cost Inclusion
- Proposed Schedule and Process

A. Premises

There are a number of key premises upon which the analysis was be based, as briefly outlined below.

- **CCS role:** CCS has undertaken the analysis of the ES options, with input and feedback from energy supply TWG members
- **Transparency:** Data sources, methods, key assumptions, and key uncertainties are to be clearly indicated.
- **Analytical approach:** The general approach was adopted of cost-effectiveness (and NPV) analysis, as widely applied to GHG mitigation policy options.[1] We include direct, economic costs from the perspective of the state as whole (e.g., avoided costs of electricity rather than consumer electricity prices).
- **Bottom-up analysis:** A bottom-up approach was adopted which is amenable to transparency and is capable of reflecting the costs (and cost savings) associated with individual policy options, in contrast to macroeconomic analysis, which aims to capture flows and interactions across all sectors of the economy. Potential macroeconomic impacts, cost or benefits that fall disproportionately on specific groups or actors, as well external costs and benefits, should be noted qualitatively where studies or other information are available.

B. Outputs

The analysis of mitigation options was organized so as to produce the following results:

- **Net GHG reduction potential** in million metric tons carbon dioxide equivalent (MMtCO_2e) using IPCC 100 yr global warming potential, reported annually for the years 2015, 2020, and

[1] See e.g.,Section 2.4 of the IPCC Fourth Assessment Report, Working Group III, for more discussion of various economic analysis approaches. http://www.mnp.nl/ipcc/pages_media/AR4-chapters.html

2025, as cumulatively for the period 2008-2025. Where significant additional GHG reductions or costs occur beyond the project period as a direct result of actions taken during the project period, these will be indicated as appropriate.

- **Net present value (NPV) cost** (or cost savings) for the period 2008–2025 in 2006 constant dollars, using a 5% real discount rate.[2] Positive numbers represent options with net costs; negative numbers represent options with net cost savings.
- **Cost per metric ton of CO_2 equivalent** emissions reduced (or removed) in units of dollar per metric ton of carbon dioxide equivalent ($/tCO2e). This figure represents the NPV cost divided by the cumulative emission reductions, both over the 2008-2025 period.

C. Methodology

The analysis proceeded using simple spreadsheet modeling techniques in which assumptions were transparent and readily accessible to any TWG member for review and adjustment. In order to ensure consistent results across options, common factors and assumptions were used for items such as:

- **Electricity avoided costs and emissions:** Common values ($/MWh and tCO2/MWh) were developed based on available studies. Each mitigation option was a) first analyzed individually and then b) addressed as part of an overall integrated analysis.
- **Fuel costs and projected escalation:** Fuel cost estimates were be based on common sources, wherever possible. For example, fossil fuel price escalation were indexed to USDOE projections as indicated in their most recent Annual Energy Outlook (i.e., 2007).
- **Overlap with other TWGs:** There were some ES options that overlapped with options being considered in the RCI TWG. The analysis for these options took place in close coordination with the assumptions other inputs used in the RCI TWG.
- **Consumption-based approach:** this approach was used which aims to reflect the emissions associated with electricity sources used to deliver electricity to consumers in Minnesota. It is distinct from a production-basis approach which considers the emissions from Minnesota power plants, regardless of where the electricity is delivered.
- **Full fuel cycle approach:** Related to the previous point, a fuel cycle analysis was applied wherever emissions impacts upstream (e.g., production, extraction) or downstream (e.g., waste disposal) from a specific activity constitute a significant fraction of a policy option's emissions impacts *and* studies were sufficient to enable estimation.

D. Assumptions

As much as possible, the analysis sought to rely on data sources that were Minnesota-specific, and which TWG members were in a good position to obtain and provide. The success of this approach depended on how accessible the information was to TWG members and the timeliness in which it was provided to the CCS analysis team.

[2] Capital investments with lifetimes longer than 2025 are represented in terms of levelized or amortized costs, in order to avoid "end effects".

Where Minnesota-specific information could not be readily obtained, the analysis relied on published data from the US Department of Energy, National Laboratories, and other state climate change processes. Specific assumptions that were needed to undertake the analysis are as outlined below. Some of these assumptions were obtained from non-Minnesota sources:

- Avoided costs associated with the most recent electric capacity expansion plans in Minnesota
- New centralized renewable installation energy cost and performance assumptions.
- New centralized fossil power station cost and performance assumptions
- Fossil fuel price forecasts to electric generator through 2025 (i.e., distillate, residual oil, natural gas, coal, biomass);
- Any studies that provide spatial and temporal (as appropriate) quantitative estimates of renewable resource potential in Minnesota (wind, solar, biomass, animal wastes)
- Any studies that provide an indication of the technical and economic potential of combined heat and power systems in Minnesota (both commercial and industrial applications)
- Any studies that provide the costs associated with integrating large amounts of intermittent renewable technologies onto the system (where integration costs are expected to increase with increasing amounts of intermittent capacity).
- Any studies that examine alternative electric sector expansion plans in Minnesota that have considered decoupling profits from sales, lost revenue adjustments, inverted block rates for residential consumers, and/or use of carbon adders.
- Any studies that examine the installation and operating costs of IGCC systems in Minnesota.

E. Cost Inclusion

There are several types of costs that were explicitly considered in the analysis and several types that were excluded, as summarized below.

- **Costs included:** Examples include the following:
  - Capital costs levelized (amortized) where appropriate, e.g., for new energy supply facilities and associated infrastructure
  - O&M and other labor costs (or incremental costs relative to standard practice),
  - Fuel and material costs, e.g., for natural gas, electricity, biomass resources, water, fertilizer, material use, electricity transmission and distribution
  - Other direct costs administrative and other costs (where readily estimated), such as the grid integration costs for renewable energy technologies
- **Costs excluded:** Examples include the following:
  - External costs such as the monetized environmental or social benefits/impacts (value of damage by air pollutants on structures, crops, etc.), quality-of-life improvements, or improved road safety, or other health impacts and benefits
  - Energy security benefits
  - Macroeconomic impacts related to the impact reduced or increased consumer spending, shifting of cost and benefits among actors in the economy

Annex 2: Key Assumptions

ES-1. Generation Performance Standard

Start year for GPS 2013

CO2e emission intensity threshold assumptions

	lbs CO2 per MWh	tonnes CO2e/MWh
MN power stations	1,100	0.50
contracts with out-of-state power stations	1,100	0.50
MN CHP stations	1,300	0.59
contracts with out-of-state CHP stations	1,300	0.59

Sensitivity regarding the effect of the GPS on planned additions in MN that are already in the pipeline

1

1 GPS has **no** effect on MN planned capacity already in the pipeline (default)
2 GPS **affects** MN planned capacity already in the pipeline

Sensitivity regarding the effect of the GPS on imports that are already in the pipeline

1

1 GPS has **no** effect on out-of-state imports already in the pipeline (default)
2 GPS **affects** out-of-state imports already in the pipeline

Sensitivies for replacement power from new utility/NUG capacity in MN to meet GPS

1

1 50% natural gas CC; 50% wind (default)
2 user-defined

Sensitivies for replacement power from new CHP capacity in MN to meet GPS

1

1 100% natural gas CC (default)
2 user-defined

Sensitivies for replacement power from imports to meet GPS

1

1 100% natural gas CC (default)
2 user-defined
3 GPS not applicable to imports

Levelized cost raw inputs (2005$/MWh)

Pulverized coal	40.3
IGCC	47.3
Hydroelectric	42.3
Natural Gas CT	102.5
Natural Gas CC	52.1
Nuclear	45.7
Other	0.0
Other Gas	0.0
Geothermal	77.1
MSW	40.1
Landfill gas	40.1
Biomass	59.8
Solar	145.5
Wind	50.6
Petroleum	132.8
Pumped Storage	0.0

Levelized cost assumptions (2005$/MWh)

	Utilities/NUGs	CHP	Imports
Coal	40.3	40.3	40.3
Hydroelectric	42.3	47.3	47.3
Natural Gas	52.1	52.1	52.1
Nuclear	45.7	45.7	45.7
Other	0.0	0.0	0.0
Other Gas	0.0	0.0	0.0
Other Renewables	50.6	0.00	0.00
Petroleum	132.8	132.8	132.8
Pumped Storage	0.0	0.0	0.0

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

Start year for option 2013

Sensitivity regarding the biomass co-firing assumption

1

1 Biomass represents 8% of fuel combusted annually at pulverized coal power stations (default)
2 User-defined (Biomass represents 15% of fuel combusted at pulverized coal power stations)

Sensitivity regarding the 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%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2009					0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2010						0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2011							0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2012								0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2013									2%	3%	5%	6%	8%	8%	8%	8%	8%	8%	8%	8%	8%
2014										0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2015											0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2016												0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2017													0%	0%	0%	0%	0%	0%	0%	0%	0%
2018														0%	0%	0%	0%	0%	0%	0%	0%
2019															0%	0%	0%	0%	0%	0%	0%
2020																0%	0%	0%	0%	0%	0%
2021																	0%	0%	0%	0%	0%
2022																		0%	0%	0%	0%
2023																			0%	0%	0%
2024																				0%	0%
2025																					0%
	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	5%	6%	8%	8%	8%	8%	8%	8%	8%	8%	8%

Financial Parameters

real discount rate 5%

CO2e emission factors (tonnes of CO2e per mmbtu)

Biomass	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020

Biomass heat rate (bt	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
MN utilities/NUGs - Referen	16,119	15,787	15,614	15,635	15,654	15,672	15,689	15,704	15,718	15,732	15,744	15,756	15,767	15,777	15,787	15,797	15,805	15,814	15,822	15,830	15,836
MN utilities/NUGs - Referen	16,119	15,214	14,799	14,851	14,899	14,944	14,986	13,813	12,771	12,134	11,704	11,667	11,632	11,601	11,572	11,546	11,484	11,429	11,379	11,338	11,291
MN utilities/NUGs - Referen	16,119	14,566	13,956	14,031	14,101	14,167	14,229	12,707	11,622	11,053	10,702	10,673	10,646	10,621	10,600	10,579	10,532	10,491	10,453	10,423	10,388

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

Capacity type	Capacity	ansmiss	xed O&	riable O&	Fuel	Total
Pulverized coal	0.0	0.0	4.5	1.6	13.8	40.3
Biomass	0.0	0.0	7.5	2.9	21.8	59.8

ES-5. Renewable and/or Environmental Portfolio Standard

Start year for RPS 2011

Financial Parameters

real discount rate	5%	Assumption

Natural gas capacity composition - All Scenarios

Combustion turbine	100%
Combined cycle	0%
total	100%

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

Capacity type	Capacity	Transmission	Fixed O&M	/ariable O&M	Fuel	Total
Pulverized coal	20.4	0.0	4.5	1.6	13.8	40.3
IGCC	25.0	0.0	5.2	3.7	13.5	47.3
Hydroelectric	35.9	0.0	3.1	3.2	0.0	42.3
Natural Gas CT	31.6	0.0	2.5	11.2	57.2	102.5
Natural Gas CC	9.4	0.0	1.6	4.1	37.0	52.1
Nuclear	26.6	0.0	8.5	0.5	10.2	45.7
Other	0.0	0.0	0.0	0.0	0.0	0.0
Other Gas	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	42.5	0.0	34.7	0.0	0.0	77.1
MSW	24.0	0.0	16.0	0.0	0.0	40.1
Landfill gas	24.0	0.0	16.0	0.0	0.0	40.1
Biomass	27.6	0.0	7.5	2.9	21.8	59.8
Solar	139.4	2.6	3.5	0.0	0.0	145.5
Wind	38.9	2.6	9.1	0.0	0.0	50.6
Petroleum	47.5	0.0	12.8	3.3	69.3	132.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0

Levelized cost assumptions (2005$/MWh)

	Capacity	Transmission	Fixed O&M	/ariable O&M	Fuel	Total
Coal	0.0	0.0	4.5	1.6	13.8	19.9
Hydroelectric	0.0	0.0	5.2	3.7	13.5	22.4
Natural Gas	0.0	0.0	2.5	11.2	57.2	70.8
Nuclear	0.0	0.0	8.5	0.5	10.2	19.1
Other	0.0	0.0	0.0	0.0	0.0	0.0
Other Gas	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	42.5	0.0	34.7	0.0	0.0	77.1
MSW	24.0	0.0	16.0	0.0	0.0	40.1
Landfill gas	24.0	0.0	16.0	0.0	0.0	40.1
Biomass	27.6	0.0	7.5	2.9	21.8	59.8
Solar	139.4	2.6	3.5	0.0	0.0	145.5
Wind	38.9	2.6	9.1	0.0	0.0	50.6
Petroleum	0.0	0.0	12.8	3.3	69.3	85.3
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0

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

Number of new IGCC units 1

Online year for new IGCC unit(s) 2013

Carbon capture & storage? No

Characteristics of new IGCC power stations

	Units	Value
Size	MW	600
Capacity factor	%	80%
Heat rate	btu/kWh	9,000
Annual gross generation	GWh/yr	4,205
coal CO2e emission factor	tCO2e/mmbtu	0.0959
new IGCC CO2e e-factor	E6 tCO2e/GWh	0.0009

Resource displaced	100%	existing coal

Financial Parameters

real discount rate	5%	Assumption

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

Capacity type	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total
Pulverized coal	20.4	0.0	4.5	1.6	13.8	40.3
IGCC	25.0	0.0	5.2	3.7	13.5	47.3

Levelized cost assumptions (2005$/MWh)

	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total
Pulverized coal	0.0	0.0	4.5	1.6	13.8	19.9
IGCC	25.0	0.0	5.2	3.7	13.5	47.3

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

Number of new IGCC/CCR units 1

Online year for new IGCC/CCR unit(s) 2013

Carbon capture & storage? Yes

Coal CO2e emission factor (tCO2e/mmbtu) 0.0959

Sensitivies for CCR technology 1

1 Central value (default)
2 High value
3 Low value

Cost & performance characteristics of new carbon capture & storage technology

		Range		
		Low	High	Central
Capture from IGCC	2005$/tCO2 captured	15.0	75.0	45.0
Transportation	2005$/tCO2 transported	1.0	8.0	4.5
Geologic storage	2005$/tCO2 injeceted	0.5	8.0	4.3
Monitoring/verification	2005$/tCO2 injected	0.1	0.3	0.2
subtotal	2005$/tCO2	16.6	91.3	54.0
Heat rate penalty	btu/kWh	3,144	476	1,764
CO2 emission reduction	%	81%	91%	86%

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

Capacity type	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total
IGCC	25.0	0.0	5.2	3.7	13.5	47.3
IGCC/CCS (low)	30.3	0.0	5.5	3.7	18.2	57.8
IGCC/CCS (mid)	34.1	0.0	5.5	3.7	16.1	59.5
IGCC/CCS (high)	37.2	0.0	5.5	3.7	13.0	59.5

Levelized cost assumptions (2005$/MWh)

	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total
Pulverized coal	0.0	0.0	4.5	1.6	13.8	19.9
IGCC	25.0	0.0	5.2	3.7	13.5	47.3
IGCC/CCS (low)	30.3	0.0	5.5	3.7	18.2	57.8
IGCC/CCS (mid)	34.1	0.0	5.5	3.7	16.1	59.5
IGCC/CCS (high)	37.2	0.0	5.5	3.7	13.0	59.5