08 - 0305

Study by the Legislative Electric Energy Task Force on nuclear energy's comparative costs

In Compliance with Minnesota Law Chapter 136 – S.F. No. 145, Article 3, Section 6

March 10, 2008

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Sec. 6. **NUCLEAR ENERGY STUDY.**

The legislative electric energy task force shall conduct an analysis of the economic and environmental costs of constructing a 600-megawatt nuclear-powered electric generating plant in Minnesota. The analysis must include predesign, design and construction costs, and waste storage costs. The study must compare these costs with the costs of constructing a pulverized coal plant with carbon capture and sequestration technology and a coal-gasification plant with carbon capture and sequestration technology. The study's findings must be submitted in a report to the chairs and ranking minority members of the committees of the house of representatives and senate with primary jurisdiction over energy policy by March 1, 2008.

Costs of New Nuclear Generation

With construction and O&M costs factored in, Xcel Energy estimates a range of $74 - $97 / MWh of electricity generated by a new nuclear plant operating in Minnesota.

Construction Costs

According to Xcel Energy's most recently filed Integrated Resource Plan, the overnight cost of constructing a new 1,350-megawatt (MW) nuclear power generating station would be $1,802 /kW; or $2,432,700,000. If that same ratio of $1,802 /KW were used to estimate the costs of a 600 MW plant, the estimate would be $1,081,200,000. These estimates do not include operation costs, nor are they the complete construction estimates, as interest costs during construction are not included. Xcel estimates they would increase the cost estimates to approximately $2,800 /kW to factor in other costs related to construction.

Factored as a \$/MWh charge, construction costs are assumed to be in a range of \$55-\$76 / MWh. The \$76/MWh figure was derived using a revenue requirement forecast method for a unit brought on line in 2020. The cost per MWh decreases over time as the rate base is reduced and the return on capital decreases. The \$55/MWh figure was derived by applying an economic carrying charge (ECC) to the capital costs. The ECC method has the same net present value (NPV) as the revenue requirements stream. However, the ECC method increases with the rate of inflation.

Operation and Maintenance Costs

Based on EIA and other estimates, O&M cost estimates excluding fuel range from \$7.80 /MWh to \$10.35 /MWh. Meanwhile, based on Xcel's experience with running the Monticello and Prairie Island reactors, they estimate a \$9.60 /MWh to \$12.80 /MWh fuel cost.

Costs of Alternative Generation Methods

What follows is a summary of other generation methods' estimated cost range. These estimates are from a document provided to the LEETF, dated January, 2007 by the Minnesota Department of Commerce for use in this report. These methods factor in the estimated range of future greenhouse gas emissions costs established by the Minnesota PUC as well as estimated emissions costs for soon to be regulated pollutants such as NOx and Hg:

Generation Fuel Type	Cost/MWh	Source
"New" Pulverized Coal	\$74-\$110	Big Stone II, est. Sherco 4, and Westmoreland (in ND)
Current Pulverized Coal	\$15-\$60	Various Utilities' IRP models
"New" IGCC Coal	\$102-\$155 (?)	Mesaba Project PPA
Current Nuclear	\$15-\$18	Various PUC proceedings
Current Natural Gas	\$52-\$105 (?)	Depending on natural gas market and contract terms
Large Hydropower	Cost ranges just below electricity market prices	Manitoba Hydro traditional pricing practices
Current & "New" Wind mandate, Green Pricing	\$25-\$60	Utilities' Wind PPA's – REO, IRP, C-BED, Xcel
Current & "New" Biomass	\$86-\$125	Current and anticipated PPA's – REO, Xcel Mandate

The following pages are sections from the Final Draft Report of the Minnesota Climate Change Advisory Group (MCCAG). This group looked into issues related to this studies scope and are included to reflect that.

Prior to the final meeting of the MCCAG, the Center for Climate Strategies had estimated that a nuclear power station, as outlined in option ES-6 built in 2020 would have a new cost to the state of $3.355 billion. Option ES-8 had the following costs for the various possibilities within the option:
New IGCC with carbon capture and sequestration (CCS) - $3.506 billion
New IGCC without CCS - $1.953 billion
Retrofitting existing coal stations with CCS - $1.623 billion
New IGCC with 1% biomass co-firing and CCS - $3.515 billion

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. *This is the specific option proposed; i.e., a study examining the issues regarding one 1,100 MW unit installed in Minnesota in the post-2025 period.*

Timing: This policy should be implemented as soon as possible.

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

Implementation Mechanisms

The planning requirements would be implemented through the IRP process already implemented by MPUC. Thorough consideration of the safety, economics, and environmental implications of nuclear power would be explicitly called for.

In addition, 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 measures 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. If a comprehensive GHG policy were implemented in the state's electric power sector, it would most 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:

- U.S. DOE, EIA, Office of Energy Statistics, *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.
- Capital cost, transmission, fixed O&M, and variable O&M escalation factors developed by the MCCAG.

Quantification Methods:

This policy would provide support and incentives for life extension at existing nuclear power plants and for study of potential new nuclear power plants in Minnesota. Since it calls for the installation of a new unit in the post-2025 time frame, it is a nonquantified option. As a sensitivity to obtain a sense of the cost-effectiveness of the option, it has been modeled as a new nuclear power station in Minnesota using the following key assumptions:

- The installation year for the station is 2020.
- Upstream fuel-cycle GHG emissions associated with nuclear generation should be accounted for.
- The size of the station is 1,100 MW.
- New nuclear power would displace generation from existing, fully depreciated coal-fired generation within Minnesota.

Figure G-16 summarizes the impacts of this policy on gross generation. The upper curve represents the total Minnesota coal generation before and after the introduction of the new nuclear station, while the lower curve represents the total Minnesota nuclear generation before and after the introduction of the new nuclear station.

Figure G-16. Impacts on gross generation, with and without new nuclear power

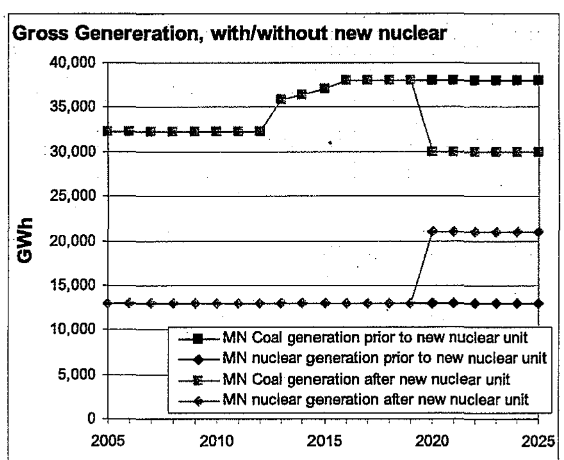
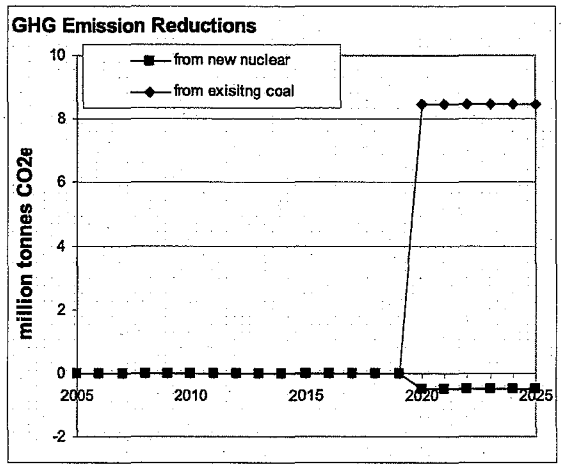


Figure G-17 summarizes the GHG reductions resulting from implementing the policy. The upper curve represents the annual CO_2e reductions associated with backed-down generation from existing coal-fired power stations in Minnesota. The lower curve represents the annual CO_2e reductions associated with increased generation from the new nuclear power station in Minnesota. The net annual emission reductions in 2015 and 2025 are 0.0 and 8.0 million tonnes of CO_2e, respectively. The cumulative net emission reductions over the 2005–2025 forecast period are 47.8 million tonnes of CO_2e.

Figure G-17. Projected GHG emission reductions from new nuclear power



The cost savings associated with avoided fuel and O&M at existing coal-fired facilities located in Minnesota is $39/MWh after deducting the capital cost component (2005$). The incremental costs associated with new nuclear power—capital costs, transmission costs, variable O&M costs, fixed O&M costs and fuel costs—total $164/MWh (2005$), which is then escalated to 2020 by 1.45 using the MCCAG escalation assumptions. The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. The NPV of these annual costs is $3.4 billion over the 2020–2025 period (2005$).

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or $70.2/t$CO_2e$ reduced (2005$) (i.e., $3.4 billion divided by 47.8 million tonnes and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 1.

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

None.

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

Complete.

Level of Group Support

Unanimous. With clarification that the state consider the costs and risks of installing a nuclear power station after 2025.

Barriers to Consensus

Not applicable.

ES-8. 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, and North and South Dakota) should strive to have at least two IGCC projects with carbon capture and storage (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, independent power producers, state regulators.

Implementation Mechanisms

- Have commercial-scale technology 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. Three demonstrations are 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 state 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 R&D programs and investments, with a focus on developing the gasification and carbon sequestration industries.
- 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 geologic storage of CO_2. 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

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 CO_2 emissions from coal combustion.

Estimated GHG Reductions and Net Costs or Cost Savings

- U.S. DOE, EIA, Office of Energy Statistics, *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
- U.S. DOE, National Energy Technology Laboratory, "Volume 1: Bituminous Coal and Natural Gas to Electricity. Final Report," in *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
- U.S. DOE, EIA, Office of Energy Statistics, "Electric Power Annual 2006—State Data Tables. 1990–2006 Net Generation by State by Type of Producer of Energy Source," EIA-906. Available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html
- Metz, Bert, Ogunlade Davidson, Peter Bosch, Rutu Dave, and Leo Meyer, eds., *Carbon Dioxide Capture and Storage: A Special Report of Working Group III of the Intergovernmental Panel on Climate Change*, New York, NY: Cambridge University Press, 2006. Available at: http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/SRCCS_WholeReport.pdf
- Katzer, J., et al., *The Future of Coal: Options for a Carbon-Constrained World*, An Interdisciplinary MIT Study, Cambridge, MA: 2007. Available at: http://web.mit.edu/coal/The_Future_of_Coal.pdf

Quantification Methods:

This policy considers the role that coal could play in Minnesota's future energy system, provided 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 a new IGCC unit with CCS.

The MCCAG considered a primary analysis and three sensitivity analyses as follows:

- Primary analysis: new IGCC with CCS
- Sensitivity analysis #1: new IGCC without CCS
- Sensitivity analysis #2: retrofit of existing coal stations with CCS
- Sensitivity analysis #3: new IGCC with 1% biomass co-firing and CCS

Primary Analysis: New IGCC With CCS

The key assumptions for the analysis of this policy are as follows:

- The start year is 2020.
- One 600-MW IGCC station is installed.
- The resources displaced by the new IGCC plant are assumed to be 10% natural gas-fired generation from combustion turbines in- and out-of-state, with the balance from existing in-state coal-fired generation.
- The capital costs associated with displaced resources are not depreciated.
- A heat rate penalty of 1,530 Btu/kWh above the assumed IGCC heat rate of 9,000 Btu/kWh is assumed to be the effect of adding CCS technology.
- A carbon capture efficiency of 86% is assumed to be the effect of adding CCS technology.
- A geologic storage site is located within 150 miles of the IGCC unit connected by a pipeline with a mass flow rate of 22.5 $MtCO_2$/yr.

Figure G-18 summarizes the impacts of this policy on gross generation for both new and displaced resources.

Figure G-18. Impacts of a new IGCC station with CCS on gross generation

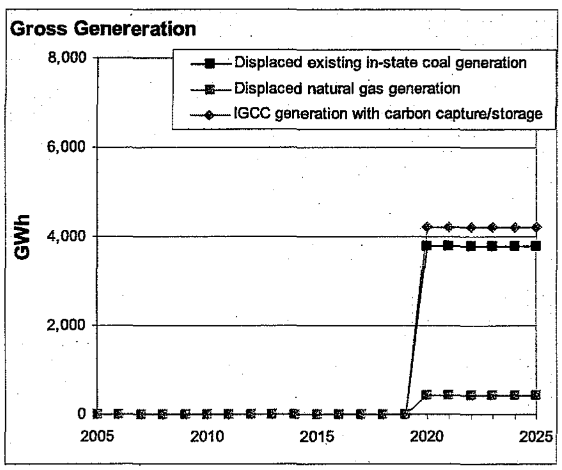
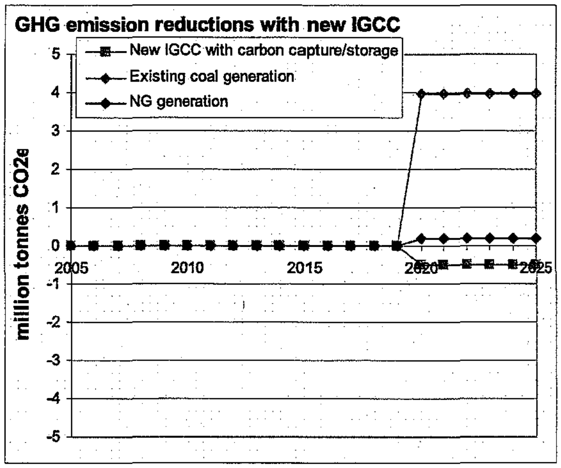


Figure G-19 presents projected CO_2e emission reductions resulting from this policy. The upper curve represents the annual CO_2e reductions associated with backed-down generation from existing coal-fired power stations in Minnesota. The curve in the middle represents the annual CO_2e reductions associated with backed-down generation from natural gas-fired power stations both in- and out-of-state. And the lower curve represents the annual CO_2e emission increases associated with the generation from the new IGCC with CCS power station in Minnesota. The net annual emission reductions in 2025 are 3.66 million tonnes of CO_2e, and the cumulative emission reductions over the 2020–2025 forecast period are 21.96 million tonnes of CO_2e.

Figure G-19. GHG emission reductions from a new IGCC station with CCS



There are cost savings associated with avoided capital, fuel, and O&M at existing coal-fired stations in Minnesota and natural gas-fired facilities (i.e., combustion turbines) located inside and outside Minnesota. The incremental costs associated with a new IGCC plant with CCS include capital costs, transmission costs, variable O&M costs, fixed O&M costs, and fuel (i.e., coal only) costs. The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. The NPV of these annual costs is $3.506 billion over the 2020–2025 period (2005$).

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or $159.7/t$CO_2e$ reduced (2005$) (i.e., $3.506 billion divided by 21.96 million tonnes and multiplied by a conversion factor of 1,000).

Sensitivity Analysis #1: New IGCC Without CCS

The key assumptions for this sensitivity analysis of this policy are as follows:

- The start year is 2020.
- One 600-MW IGCC station is installed.
- The resources displaced by the new IGCC plant are assumed to be 10% natural gas-fired generation from combustion turbines in- and out-of-state, with the balance from existing in-state coal-fired generation.
- The capital costs associated with displaced resources are not depreciated.

Figure G-20 summarizes the impacts of this policy on gross generation.

Figure G-20. Impacts of a new IGCC station without CCS on gross generation

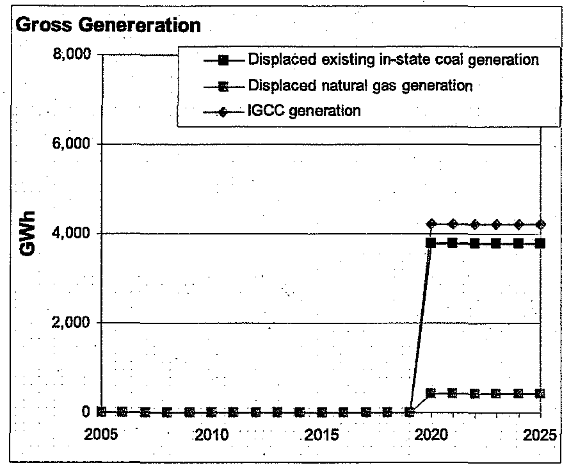
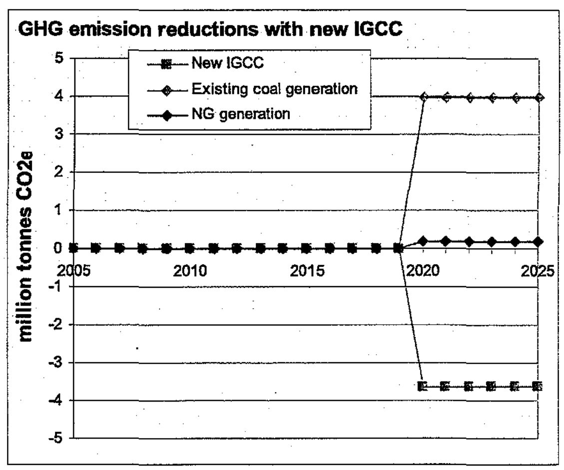


Figure G-21 summarizes the projected CO_2e emission reductions resulting from this policy's implementation. The upper curve represents the annual CO_2e reductions associated with backed-down generation from existing coal-fired power stations in Minnesota. The curve in the middle represents the annual CO_2e reductions associated with backed-down generation from natural gas-fired power stations both in- and out-of-state. And the lower curve represents the annual CO_2e emission increases associated with the generation from the new IGCC power station in Minnesota. The net annual emission reductions in 2015 and 2025 are 0.0 and 0.5 million tones of CO_2e, respectively, and the cumulative emission reductions over the 2020–2025 forecast period are 3.2 million tonnes of CO_2e.

Figure G-21. GHG emission reductions from a new IGCC station without CCS



There are cost savings associated with avoided capital, fuel, and O&M at existing coal-fired stations in Minnesota and natural gas-fired facilities (i.e., combustion turbines) located inside Minnesota and outside Minnesota. The incremental costs associated with a new IGCC plant include capital costs, transmission costs, variable O&M costs, fixed O&M costs, and fuel costs. The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. The NPV of these annual costs is $1.95 billion over the 2020–2025 period (2005$).

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or $606.5/t$CO_2$e reduced (2005$) (i.e., $1.95 billion divided by 3.2 million tonnes and multiplied by a conversion factor of 1,000).

Sensitivity Analysis #2: Retrofitting Existing Pulverized Coal Stations With CCS

The key assumptions for this sensitivity analysis of this policy are as follows:

- The start year is 2020.
- One 500-MW IGCC station is installed using chemical absorption with monoethanolamine (MEA) for carbon capture.
- One 500-MW IGCC station is installed using oxygen firing for carbon capture.
- A plant de-rating of 41% is assumed for MEA and 36% for oxygen firing. Make-up power is available from in-state pulverized coal stations.
- Carbon capture efficiencies are 83% for MEA and 84% for oxygen-firing.
- A geologic storage site is located within 150 miles of the units connected by a pipeline with a mass flow rate of 22.5 MtCO_2/yr.

Figure G-22 summarizes the impacts of this policy on gross generation in Minnesota.

Figure G-22. Impacts on gross generation from retrofitting existing pulverized coal stations with CCS

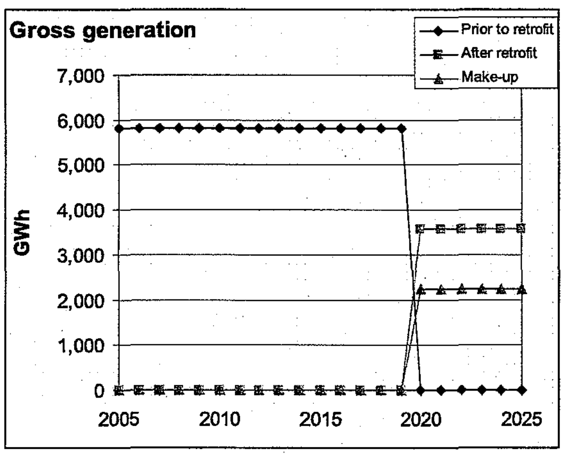
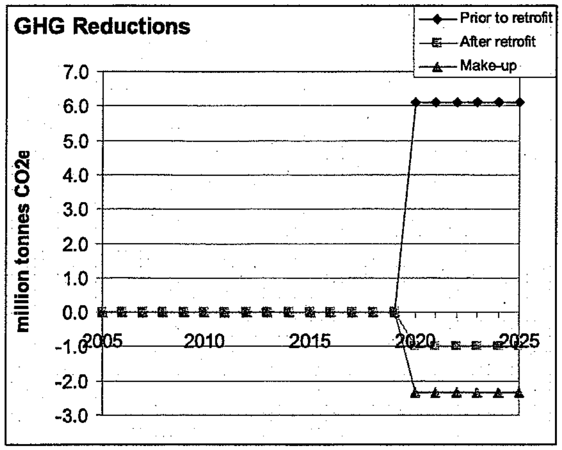


Figure G-23 summarizes the projected CO_2e emission reductions resulting from the implementation of this policy. The upper curve represents the annual CO_2e reductions associated with the existing coal-fired power stations in Minnesota prior to retrofitting. The curve in the middle represents the annual CO_2e emissions associated with the retrofitted coal stations. And the lower curve represents the annual CO_2e emissions associated with make-up power. The net annual emission reductions in 2015 and 2025 are 0.0 and 2.8 million tones of CO_2e, respectively, and the cumulative emission reductions over the 2020–2025 forecast period are 16.7 million tonnes of CO_2e.

Figure G-23. GHG emission reductions from retrofitting existing pulverized coal stations with CCS



The incremental costs associated with retrofitting are incremental capital costs, variable O&M costs, fixed O&M costs, and fuel costs. The annual product of real levelized costs and displaced generation is an estimate of the annual costs. The NPV of these annual costs is $1.6 billion over the 2020–2025 period (2005$).

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or $97.2/tCO$_2$e reduced (2005$) (i.e., $1.6 billion divided by 16.7 million tonnes and multiplied by a conversion factor of 1,000).

Sensitivity Analysis #3: New IGCC With 1% Biomass Co-Firing and CCS

The key assumptions for this sensitivity analysis of this policy are as follows:

- The start year is 2020.
- One 600-MW IGCC station is installed.
- The resources displaced by the new IGCC plant are assumed to be 10% natural gas-fired generation from combustion turbines in- and out-of-state, with the balance from existing in-state coal-fired generation.
- The capital costs associated with displaced resources are not depreciated.
- A heat rate penalty of 1,530 Btu/kWh above the assumed IGCC heat rate of 9,000 Btu/kWh is assumed to be the effect of adding CCS technology.
- A carbon capture efficiency rate of 86% is assumed from adding CCS technology.
- A geologic storage site is located within 150 miles of the IGCC unit connected by a pipeline with a mass flow rate of 22.5 MtCO$_2$/yr.
- Coal is co-fired with biomass at 1% on an energy basis.

Figure G-24 summarizes the impacts of this policy on gross generation for both new and displaced resources. The total level of generation associated with the biomass portion of output from the IGCC unit is 42 gigawatt-hours from 2020 through 2025.

Figure G-24. Impacts on gross generation from a new IGCC station with 1% biomass co-firing and CCS

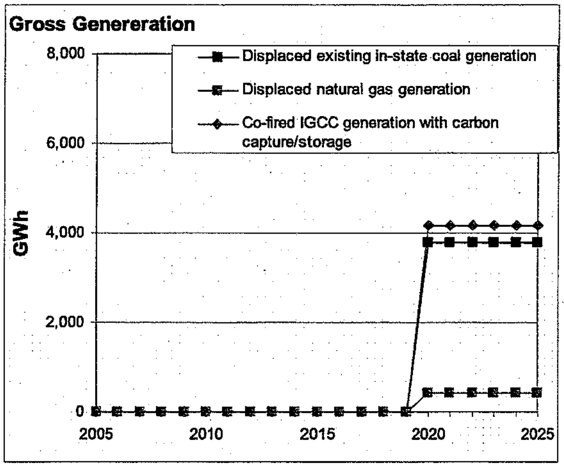
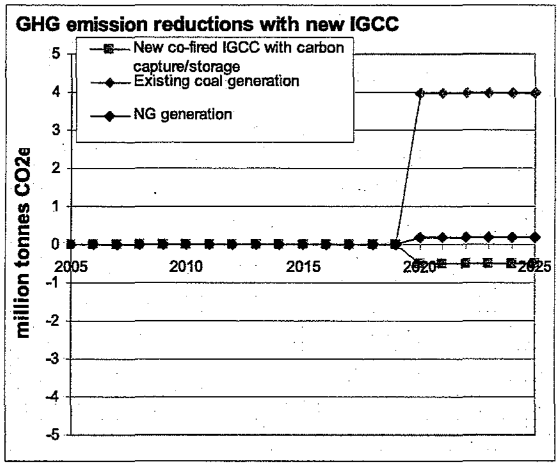


Figure G-25 summarizes the projected CO_2e emission reductions resulting from implementing this policy. The upper curve represents the annual CO_2e reductions associated with backed-down generation from existing coal-fired power stations in Minnesota. The curve in the middle represents the annual CO_2e reductions associated with backed-down generation from natural gas-fired power stations both in- and out-of-state. And the lower curve represents the annual CO_2e emission increases associated with the generation from the new IGCC with CCS power station in Minnesota.

Annually, 0.04 million tonnes of biogenic CO_2e emissions from biomass are captured and stored at the geologic storage site. This level represents an incremental sequestration amount that would otherwise not be accounted for, as biomass is assumed to be used in a sustainable manner. Cumulatively, 0.26 million tones of biogenic CO_2e emissions are captured and stored at the geologic storage site.

The net annual emission reductions in 2025 are 3.71 million tones of CO_2e. The cumulative emission reductions over the 2020–2025 forecast period are 22.25 million tonnes of CO_2e.

Figure G-25. GHG emission reductions from a new IGCC station with 1% biomass co-firing and CCS



here are cost savings associated with avoided capital, fuel, and O&M at existing coal-fired stations in Minnesota and natural gas-fired facilities (i.e., combustion turbines) located inside Minnesota and outside Minnesota. The incremental costs associated with new IGCC with CCS include capital costs, transmission costs, variable O&M costs, fixed O&M costs, and fuel (i.e., coal and biomass) costs. The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. The NPV of these annual costs is $3.515 billion over the 2020–2025 period (2005$).

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or $158.0/t$CO_2$e reduced (2005$) (i.e., $3.515 billion divided by 22.25 million tonnes and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 1.

Key Uncertainties

The mix of resources that is displaced by the new IGCC station.

Additional Benefits and Costs

Installation of more efficient technology.

Feasibility Issues

The technology is currently in the demonstration stage.

Status of Group Approval

Complete.

Level of Group Support

Unanimous. With clarification that Minnesota consider studying and/or facilitating CCS demonstration projects in the post-2025 period, including CCS paired with biomass.

Barriers to Consensus

Not applicable.