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-8	Advanced Fossil Fuel Technology Incentives, Support or Requirements						
	New IGCC with carbon capture and storage	**0.00**	**3.66**	**21.96**	**$3,506**	**159.7**	Pending
	New IGCC without carbon capture and storage	0.0	0.5	3.2	$1,953	$606.5	Pending
	Retrofitting existing coal stations with carbon capture and storage	0.0	2.8	16.7	$1,623	$97.2	Pending
	New IGCC with 1% biomass co-firing and carbon capture and storage	0.00	3.71	22.25	$3,515	$158.0	Pending

Notes:

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

2. All option totals 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-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, 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.
- 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

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
- Intergovernmental Panel on Climate Change (IPCC), "Carbon Capture and Storage," 2006.
- "The Future of Coal: Options for a Carbon-Constrained World, MIT, 2007, available at http://web.mit.edu/coal/The_Future_of_Coal.pdf

Quantification Methods:

This option considers the role that coal could play in Minnesota's future energy system, providing its overall environmental profile improves and comes close to producing zero CO_2 emissions, while producing energy that is both affordable and reliable. It has been modeled thus far as a new IGCC unit with carbon and storage.

The TWG has considered a primary analysis and two sensitivity analyses as follows:

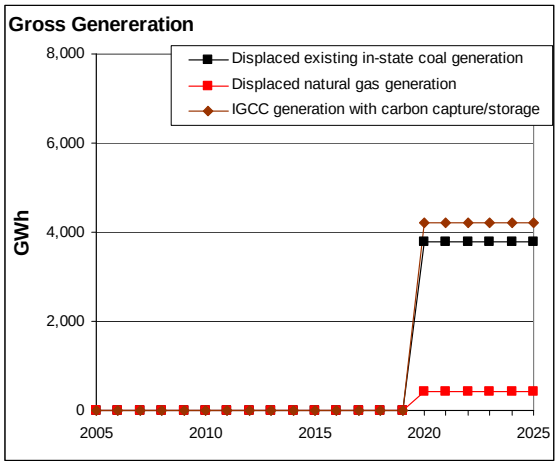
- *Primary analysis:* new IGCC with carbon capture and storage (CCS)
- *Sensitivity analysis #1:* new IGCC without CCS
- *Sensitivity analysis #2:* retrofit of existing coal stations with CCS
- *Sensitivity analysis #3:* new IGCC with 1% biomass co-firing and carbon capture and storage (CCS)

Primary analysis: new IGCC with carbon capture and storage

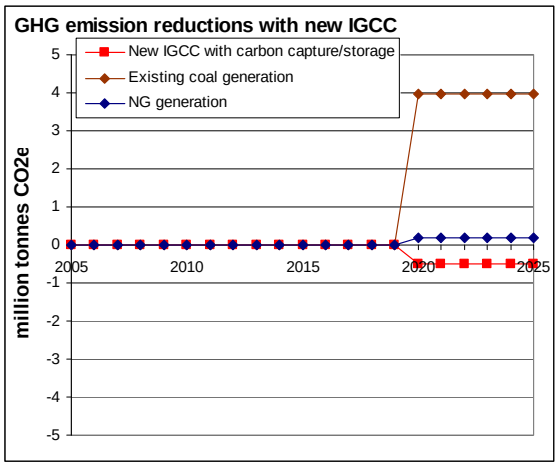
The TWG has made the following key assumptions for the analysis of this option, as follows:

- The start year for the option 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 from adding CCS technology.
- Assumes a geologic storage site within 150 miles of the IGCC unit connected by a pipeline with a mass flow rate of 22.5 MtCO2/yr.

Regarding generation, the impact of the option is summarized in the chart below for both new and displaced resources.



Regarding CO2-equivalent (CO2e) emission reductions, the impact of the option is summarized in the chart below. The upper curve represents the annual CO2e reductions associated with backed down generation from existing coal-fired power stations in MN. The curve in the middle represents the annual CO2e reductions associated with backed down generation from natural gas-fired power stations both in- and out-of-state. The lower curve represents the annual CO2e emission increases associated with the generation from the new IGCC with CCS power station in MN. The net annual emission reductions in 2025 are 3.66 million tonnes CO2e. The cumulative emission reductions over the 2020-2025 forecast period are 21.96 million tonnes CO2e.



Regarding costs, there are cost savings associated with avoided capital, fuel and O&M at existing coal-fired stations in MN and natural gas-fired facilities (i.e., combustion turbines) located in MN and outside MN. There are incremental costs associated with new IGCC with CCS 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 net present value of these annual costs are $3.506 billion over the 2020-2025 period (2005$).

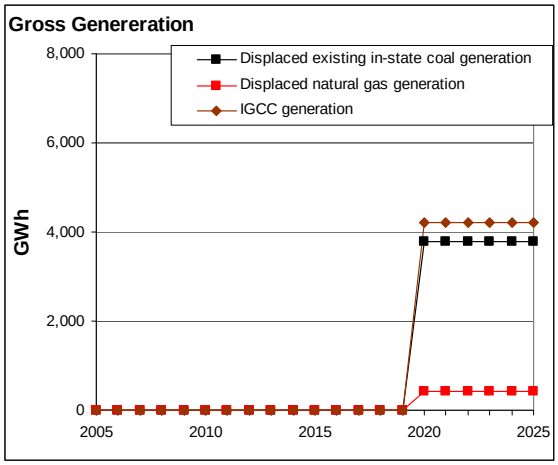
Regarding the cost effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, $159.7/tCO2e (2005$) (i.e., $3.506 billion divided by 21.96 million tonnes and multiplied by a conversion factor of 1,000).

Sensitivity analysis #1: new IGCC without carbon capture and storage

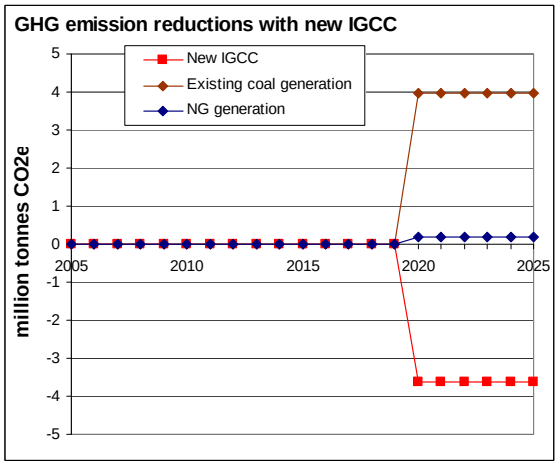
The TWG has made the following key assumptions for the analysis of this option, as follows:

- The start year for the option 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.

Regarding generation, the impact of the option is summarized in the chart below for the new and displaced resources.



Regarding CO2-equivalent (CO2e) emission reductions, the impact of the option is summarized in the chart below. The upper curve represents the annual CO2e reductions associated with backed down generation from existing coal-fired power stations in MN. The curve in the middle represents the annual CO2e reductions associated with backed down generation from natural gas-fired power stations both in- and out-of-state. The lower curve represents the annual CO2e emission increases associated with the generation from the new IGCC power station in MN. The net annual emission reductions in 2015 and 2025 are 0.0 and 0.5 million tonnes CO2e, respectively. The cumulative emission reductions over the 2020-2025 forecast period are 3.2 million tonnes CO2e.



Regarding costs, there are cost savings associated with avoided capital, fuel and O&M at existing coal-fired stations in MN and natural gas-fired facilities (i.e., combustion turbines) located in MN and outside MN. There are incremental costs associated with new IGCC 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 net present value of these annual costs are $1.95 billion over the 2020-2025 period (2005$).

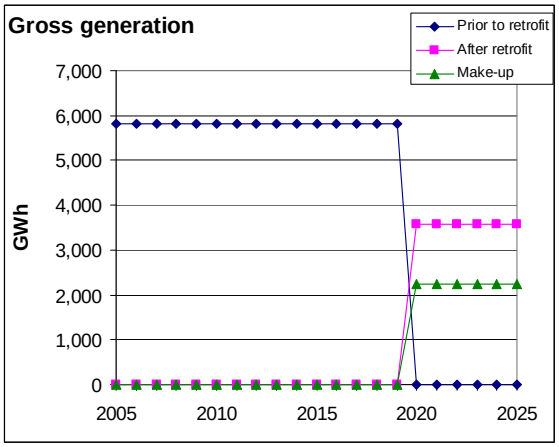
Regarding the cost effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, $606.5/tCO2e (2005$) (i.e., $1.95 billion divided by 3.2 million tonnes and multiplied by a conversion factor of 1,000).

Sensitivity analysis #2: retrofitting existing pulverized coal stations with carbon capture and storage

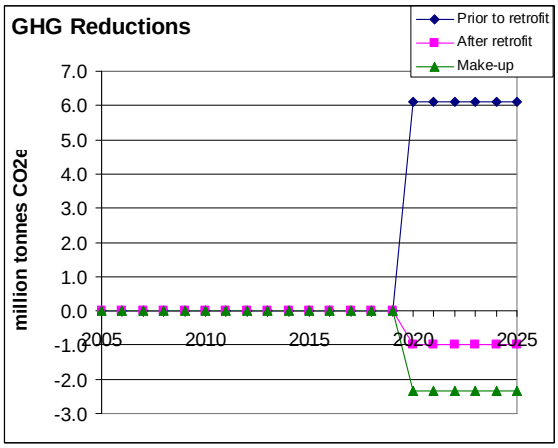
The TWG has made the following key assumptions for the analysis of this option, as follows:

- The start year for the option 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 derating of 41% is assumed for MEA and 36% for oxygen-firing. Make-up power is assumed available from in-state pulverized coal stations.
- Carbon capture efficiencies are assumed to be 83% for MEA and 84% for oxygen-firing.
- Assumes a geologic storage site within 150 miles of the units connected by a pipeline with a mass flow rate of 22.5 MtCO2/yr.

Regarding generation, the impact of the option is summarized in the chart.



Regarding CO2-equivalent (CO2e) emission reductions, the impact of the option is summarized in the chart below. The upper curve represents the annual CO2e reductions associated with the existing coal-fired power stations in MN prior to retrofitting. The curve in the middle represents the annual CO2e emissions associated with the retrofitted coal stations. The lower curve represents the annual CO2e emissions associated with make-up power. The net annual emission reductions in 2015 and 2025 are 0.0 and 2.8 million tonnes CO2e, respectively. The cumulative emission reductions over the 2020-2025 forecast period are 16.7 million tonnes CO2e.



Regarding costs, there are incremental costs associated with retrofitting, namely 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 net present value of these annual costs are $1.6 billion over the 2020-2025 period (2005$).

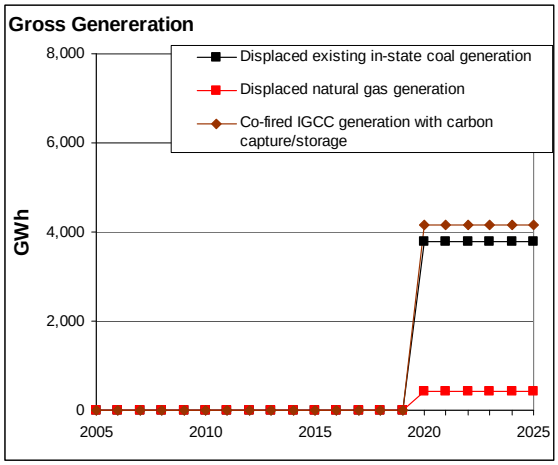
Regarding the cost effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, $97.2/tCO2e (2005$) (i.e., 1.6 billion divided by 16.7 million tonnes and multiplied by a conversion factor of 1,000).

Sensitivity analysis #3: new IGCC with 1% biomass co-firing and carbon capture and storage

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

- The start year for the option 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 from adding CCS technology.
- Assumes a geologic storage site within 150 miles of the IGCC unit connected by a pipeline with a mass flow rate of 22.5 MtCO2/yr.
- Coal is co-fired with biomass at 1% on an energy basis

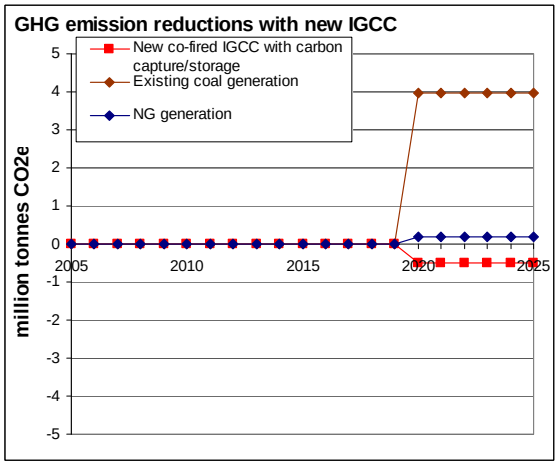
Regarding generation, the impact of the option is summarized in the chart below for both new and displaced resources. The total level of generation associated with the biomass portion of output from the IGCC unit is 42 GWh from 2020 through 2025.



Regarding CO2-equivalent (CO2e) emission reductions, the impact of the option is summarized in the chart below. The upper curve represents the annual CO2e reductions associated with backed down generation from existing coal-fired power stations in MN. The curve in the middle represents the annual CO2e reductions associated with backed down generation from natural gas-fired power stations both in- and out-of-state. The lower curve represents the annual CO2e emission increases associated with the generation from the new IGCC with CCS power station in MN.

An annual total of 0.04 million tonnes of biogenic CO2e 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 CO2e emissions are captured and stored at the geologic storage site.

The net annual emission reductions in 2025 are 3.71 million tonnes CO2e. The cumulative emission reductions over the 2020-2025 forecast period are 22.25 million tonnes CO2e.



Regarding costs, there are cost savings associated with avoided capital, fuel and O&M at existing coal-fired stations in MN and natural gas-fired facilities (i.e., combustion turbines) located in MN and outside MN. There are incremental costs associated with new IGCC with CCS 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 net present value of these annual costs are $3.515 billion over the 2020-2025 period (2005$).

Regarding the cost effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, $158.0/tCO2e (2005$) (i.e., $3.515 billion divided by 22.25 million tonnes and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 2.

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

Technology currently in demonstration stage

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-8. Advanced Fossil Fuel Technology Incentives, Support or Requirements

Assumptions for Primary analysis: new IGCC with carbon capture and storage

Number of new IGCC/CCR units 1

Online year for new IGCC/CCR unit(s) 2020

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 IGCC power stations

	Units	Value	Source
Size	MW	600	Assumption
Capacity factor	%	80%	Assumption
Heat rate	btu/kWh	9,000	Assumption
Annual gross generation	GWh/yr	4,205	Assumption

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	11,880	9,270	10,530
CO2 emission reduction		%	81%	91%	86%

Resource displaced

2

1 existing coal represents 100% of the resource displaced by the new IGCC plant
2 existing NG on the MISO system represents 10% of the resource displaced by the new IGCC plant
with the balance of 90% being existing in-state coal displaced by the new IGCC plant

Financial status of displaced resource

1

1 not depreciated
2 fully depreciated (default)

Levelized cost assumptions (2005$/MWh)

	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total
Pulverized coal	68.8	2.3	5.9	8.5	23.1	108.7
IGCC	122.3	2.5	8.8	11.4	22.6	167.6
IGCC/CCS (low)	142.3	2.7	9.4	11.4	17.8	183.5
IGCC/CCS (mid)	154.6	2.7	9.4	11.4	15.8	193.8
IGCC/CCS (high)	164.5	2.7	9.4	11.4	13.9	201.8
Natural gas CT	32.0	4.0	1.4	20.5	158.8	216.6

Assumptions for Sensitivity analysis #1: new IGCC without carbon capture and storage

Number of new IGCC units 1

Online year for new IGCC unit(s) 2020

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	0.0009

Resource displaced

2

1 existing coal represents	100%	of the resource displaced by the new IGCC plant
2 existing NG on the MISO system represents	10%	of the resource displaced by the new IGCC plant
with the balance of	90%	being existing in-state coal displaced by the new IGCC plant

Financial status of displaced resource

1

1 not depreciated (default)
2 fully depreciated

Levelized cost assumptions (2005$/MWh)

	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total
Pulverized coal	68.8	2.3	5.9	8.5	23.1	108.7
IGCC	122.3	2.5	8.8	11.4	22.6	167.6
Natural gas CT	32.0	4.0	1.4	20.5	158.8	216.6

Assumptions for Sensitivity analysis #2: retrofitting existing pulverized coal stations with carbon capture and storage

Type of coal station(s) to be retrofitted subcritical coal

Number of retrofitted coal station(s) 2

Online year for retrofitted coal stations unit(s) 2020

Carbon capture & storage for retroitted unit? Yes

Assumed retrofitting costs for coal stations for carbon capture

Typical coal plant capacity (MW)	500	
	MEA	Oxy-firing
derating	41%	36%
Coal plant capacity factor (%)	66%	66%
Incremental Capital cost (2005$/kW)	1,604	1,044
Incremental Capital cost (2005$/kWh)	0.0335	0.0218
Incremental O&M cost (2005$/kWh)	0.0121	0.0161
Heat rate before retrofit (btu/kWh)	9,749	9,749
Heat rate after retrofit (btu/kWh)	16,644	15,164
efficiency penalty (btu/kWh)	6,895	5,416
Carbon capture (%)	83%	84%

Incremental cost components for carbon capture

	Cost and performacne assumptions					First Year Non-Fuel Values							
						Non-fuel				Fuel price			
	Capital	Trans	Fixed O&M	Var O&M	Cap factor	Capital	Trans	Fixed O&M	Var O&M	Fuel price	Heat rate	Fuel cost	Total
Capture type	2005 $/kW	2005 $/kW	2005 $/kW-yr	2005 mills/kWh	%	2005 $/kWh	2005 $/kWh	2006 $/kWh	2005 $/kWh	2005$/mmbtu	btu per kWh	2005$/kWh	2005 $/kWh
MEA	1,604	0.00	0.00	12.10	66%	0.0335	0.0000	0.0000	0.0121	1.40	6,895	0.0096	0.0456
Oxy-firing	1,044	0.00	0.00	16.10	66%	0.0218	0.0000	0.0000	0.0161	1.40	5,416	0.0076	0.0379

Incremental levelized costs (including escalation)

	Capacity ($/kWh)			Transmission ($/kWh)			Fixed O&M ($/kWh)			Variable O&M ($/kWh)			Fuel ($/kWh)			Total ($/kWh)		
		Levelized Cost			Levelized Cost			Levelized Cost			Levelized Cost			Levelized Cost			Levelized Cost	
Capture type	NPV	Nominal	Real	NPV	Nominal	Real	NPV	Nominal	Real	NPV	Nominal	Real	NPV	Nominal	Real	NPV	Nominal	Real
MEA	0.463	0.050	0.037	0.000	0.000	0.000	0.000	0.000	0.000	0.148	0.016	0.012	0.129	0.014	0.010	0.739	0.079	0.059
Oxy-firing	0.301	0.032	0.024	0.000	0.000	0.000	0.000	0.000	0.000	0.197	0.021	0.016	0.101	0.011	0.008	0.599	0.064	0.048

Assumed cost and performance characteristics for retrofitting coal stations for carbon capture

source: See Appendix 3.E of "The Future of Coal: Options for a Carbon-Constrained World, MIT, 2007

	Units	on-retrofitte	MEA	Oxy-firing
Size	MW	500		
derating required	%	0%	41%	36%
Capacity after derating	MW	500	295	321
Capacity factor	%	66%	66%	66%
efficiency penalty	btu/kWh	0	6,895	5,416
Heat rate	btu/kWh	10,949	17,844	16,364
Annual gross generation	GWh/yr	2,907	1,715	1,863
Annual primary energy use	billion btu	31,827	30,604	30,493
CO2e emission factor	tCO2e/mmbtu	0.0959	0.0959	0.0959
Carbon capture	%	0%	83%	84%
CO2e emission factor	E6	0.0011	0.0003	0.0003
CO2e emissions	E6 tCO2e/yr	3.0537	0.5052	0.4719
CO2e captured	E6 tCO2e/yr	0.0	2.4312	2.4538
Incremental levelized cost - capture	2005$/MWh	0.0	59.6	48.2
Incremental levelized cost - transport/s	2005$/tCO2	0.0	9.0	9.0

Assumed cost and performance characteristics of make-up power

	Units	MEA	Oxy-firing
Type of station	NA	subcritical coal	
Annual gross generation make-up	GWh/yr	1,192	1,044
Levelized capital cost	2005$/MWh	0.00	0.00
Levelized transmission cost	2005$/MWh	0.00	0.00
Levelized fixed O&M cost	2005$/MWh	5.92	5.92
Levelized variable O&M cost	2005$/MWh	8.53	8.53
Levelized fuel cost	2005$/MWh	23.10	23.10
Total levelized cost	2005$/MWh	37.55	37.55

Assumptions for Sensitivity analysis #3: new IGCC co-fired with 1% biomass, with carbon capture and storage

Number of new IGCC/CCR units 1

Online year for new IGCC/CCR unit(s) 2020

Carbon capture & storage? Yes

Coal CO2e emission factor (tCO2e/mmb 0.0959

Sensitivies for CCR technology 1

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

Cost & performance characteristics of new IGCC power stations

	Units	Value	Source
Size	MW	600	Assumption
Capacity factor	%	80%	Assumption
Heat rate	btu/kWh	9,000	Assumption
Annual gross generation	GWh/yr	4,205	Assumption

Cost & performance characteristics of new carbon capture & storage technology

			Range		
			Low	High	Central
Capture from IGCC		005$/tCO2 capture	15.0	75.0	45.0
Transportation		05$/tCO2 transport	1.0	8.0	4.5
Geologic storage		005$/tCO2 injecete	0.5	8.0	4.3
Monitoring/verification		2005$/tCO2 injecte	0.1	0.3	0.2
	subtotal	2005$/tCO2	16.6	91.3	54.0
Heat rate (including penalty)		btu/kWh	11,880	9,270	10,530
CO2 emission reduction		%	81%	91%	86%

Resource displaced 2

1 existing coal represents 100% of the resource displaced by the new IGCC plant
2 existing NG on the MISO sys 10% of the resource displaced by the new IGCC plant
with the balance of 90% being existing in-state coal displaced by the new IGCC plant

Financial status of displaced resource 1

1 not depreciated
2 fully depreciated (default)

Levelized cost assumptions (2005$/MWh)

	Capacity	ransmissi	ixed O&	ariable O&	Fuel	Total
Pulverized coal	22.9	2.3	5.9	8.5	23.1	62.8
IGCC	122.3	2.5	8.8	11.4	22.6	167.6
IGCC/CCS (low)	142.3	2.7	9.4	11.4	17.8	183.5
IGCC/CCS (mid)	154.6	2.7	9.4	11.4	15.8	193.8
IGCC/CCS (high)	164.5	2.7	9.4	11.4	13.9	201.8
Natural gas CT	10.7	4.0	1.4	20.5	158.8	195.3

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 1 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									0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
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																1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%

Biogenic biomass emission factor

29.9 tC per TJ
0.12 tCO2/mmbtu

Levelized biomass fuel price (2005$/MWh)

40