EISPC

EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

Current State and Future Direction of Coal-fired Power in the Eastern Interconnection

Final Study Report
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ICF Incorporated
For EISPC and NARUC

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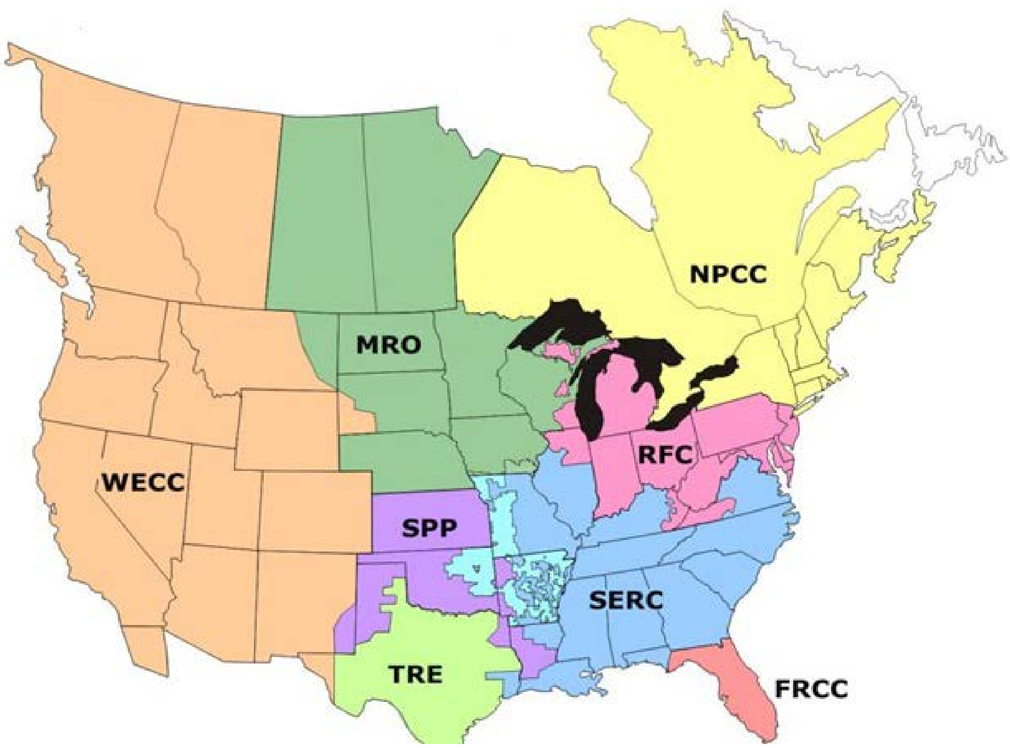
Introduction

The Eastern Interconnection States' Planning Council (EISPC) represents the 39 states, the District of Columbia, the City of New Orleans, and the 8 Canadian Provinces located within the Eastern Interconnection electric transmission grid. The goal of the group is to evaluate transmission development options throughout the Eastern Interconnection (EI).

This ICF study, "Assessment of Coal-fired Capacity in the Eastern Interconnection", is intended to provide EISPC members with accurate, comprehensive, and timely information to assist in the formulation of resource policies, with a specific focus on coal generation. The study will examine various coal technologies in the context of demand for electricity, the diversity of resources, and environmental requirements, and is intended to be a foundational resource for future EISPC modeling efforts. The study focuses the U.S. portion of the following six North American Electric Reliability (NERC) regions in the Eastern Interconnection: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RFC), Southeast Electric Reliability Council (SERC), and Southwest Power Pool (SPP).

Exhibit 1: NERC Assessment Areas Map



Source: Federal Energy Regulatory Commission, Market Oversight

The overall outlook for the development of new coal-fired plants is uncertain due to a number factors, including:

- The very large capital investment and long lead time for development necessary for new coal plants. This makes these plants a difficult investment for merchant generators to fund while also being difficult for regulated utilities to gain cost recovery approval in a changing policy and fuel market environment. Other less capital intensive options can often be more attractive.

- The variety of new environmental regulations under development for the last 20 years. While there has been substantial uncertainty as to the exact requirements due to petitions and pending decisions, it has been clear that they will be more stringent and require higher capital investment. The potential for regulation of CO_2 emissions, and most recently, the proposed greenhouse gas New Source Performance Standard (see below for more detailed description) for power plants has been a particular source of risk and uncertainty.

- Regulatory and cost uncertainty have complicated the approval process for regulated utilities who are interested in building coal plants and have increased the risk for potential builders of merchant coal plants.

- The significant developments around shale gas development and the decline in prices over the last few years have skewed interest towards construction of gas-fired plants. The current low gas prices and the lower capital cost of gas plants relative to coal plants are a strong impediment to coal plant construction.

- Opposition to coal plant construction from environmental or local citizen groups in some locations has slowed the construction of some plants.

In addition to these broader trends, the recent EPA proposal of New Source Performance Standards (NSPS) for greenhouse gases (GHGs) from power plants effectively requires the inclusion of Carbon Capture and Storage (CCS) for a new coal plant at some point in its life. If this proposal is finalized in its current form, it effectively prohibits new coal plant construction until the technology and infrastructure for CCS can be more fully developed and demonstrated. This makes the characterization and assessment of the technical, infrastructure, regulatory, legal and policy aspects of CCS a critical component of this study.[1] However, even in the absence of the NSPS, conventional environmental regulations, high capital cost, and gas competition issues remain as key challenges for coal plant construction.

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[1] On June 25, 2013, President Obama announced in the President's Climate Action Plan that he is issuing a Presidential Memorandum directing the EPA to effectively reissue carbon pollution standards for <u>new</u> generating sources, and for the first time, to issue carbon standards for existing sources.

New environmental regulations and low gas prices are two principal drivers of the current challenging environment for existing coal plants. Somewhere between 35 and 60 GW of coal capacity is expected to be shut down within the next 3 to 5 years because installing control equipment to become compliant will not be cost-effective, particularly in the face of low gas prices and potential future GHG restrictions. Most of the plants threatened with closure will be smaller and have low capacity factors, although local capacity constraints could complicate retirement plans, potentially requiring new capacity and/or transmission investments to maintain reliability. Therefore, it is critical to understand the regulatory and market drivers that will bring about these shutdowns.

The report below is divided into 6 different tasks, which cover the analysis conducted by ICF for EISPC:

- Task 1: Background information on coal fired power plants in the EI, along with historical data and forecasts on generation mix, historic and future coal demand, cost of coal power generation, estimates of coal reserves, coal transportation issues, and CO_2 pipelines and storage.

- Task 2: Evaluation of current and upcoming environmental regulations related to coal-fired power plants.

- Task 3: Evaluation of coal power technologies, including CCS. ICF determined the capital cost, operation and maintenance costs, and levelized cost of generation for various technologies, and collected information on demonstration and commercial plants in the US using these technologies.

- Task 4: Overview and costs for environmental retrofits for coal power plants.

- Task 5: Detailed analysis of the three elements of CCS, and an evaluation of state level permitting and other legal issues for storage. There is some overlap in this section with the last part of Task 1.

- Task 6: Discussion of: a) state level incentives and discentives for coal-based generation, b) impact of shale gas development, and c) impact of power markets in the EI on coal power plants.

This project report is complementary to a seperate Whitepaper that ICF has developed for EISPC. The Whitepaper provides a summary and conclusion of analysis described in this report.

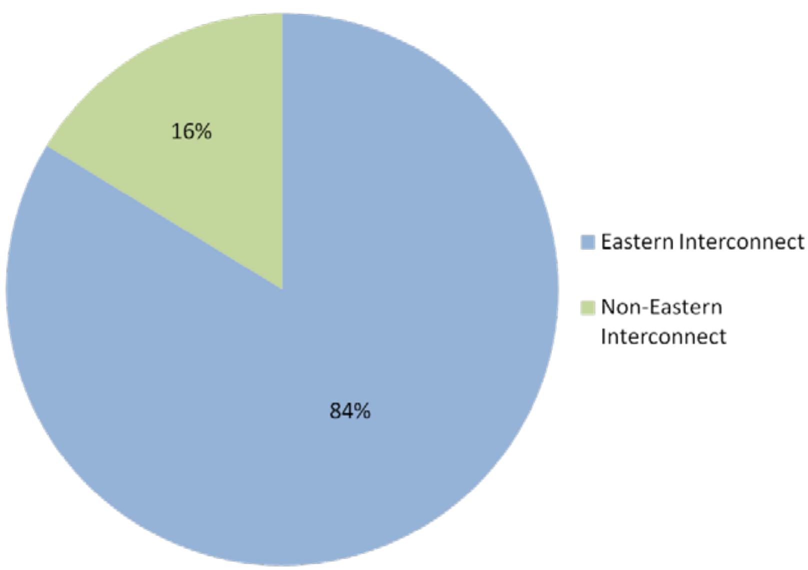
Task 1: Background and Context for Coal-fired Units in the EI

1.1 State-by-State Detail of Coal-fired Units

In this task, ICF characterized the coal-fired units in the EISPC region using EPA's National Electric Energy Data System (NEEDS) v4.10_MATS. NEEDS contains all of the generation units included in EPA's modeling using the Integrated Planning Model (IPM®), and provides extensive details for each unit including but not limited to: unit name, state, county, capacity type, fuel type, emissions controls, and emission rates/removals (NO_x, SO_2, Hg, and HCl). Further, NEEDS includes the EPA IPM® Model region for each unit which allows the units to be aggregated up to NERC region. The unit level results was provided to the EISPC in spreadsheet form in an Excel file.

Using NEEDS, ICF summarized the characteristics for all of the coal units located in the Eastern Interconnect. While NEEDS covers the entire U.S., units located in ERCOT and WECC were removed to reduce the list of plants to those in solely located in the EI. There are roughly 320 GW of coal capacity at 1,264 units nationwide, of which 269 GW of capacity and 1,099 units are part of the EI. This comprises about 84% of U.S. coal capacity (Exhibit 2).

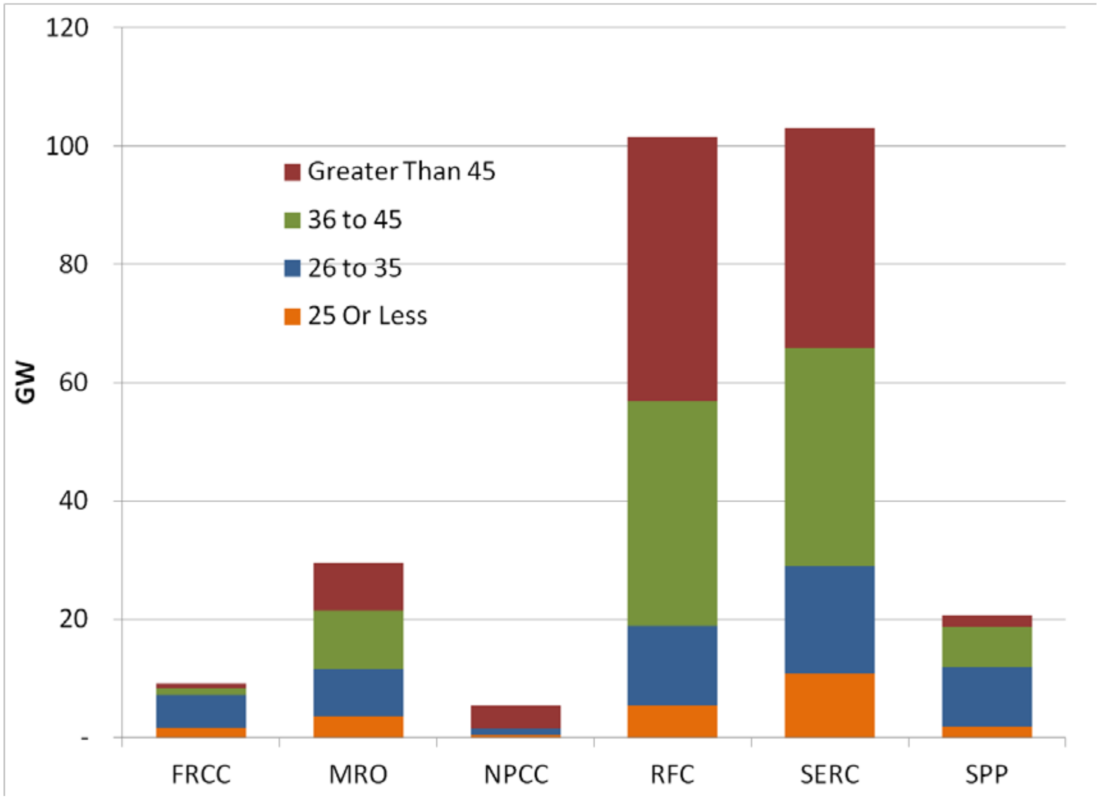
Exhibit 2: The Eastern Interconnection Share of U.S. Coal Capacity



Source: EPA, NEEDS v4.10_MATS

Regionally, 204 GW (75% of national coal capacity) of coal capacity in the EI is located in two NERC regions: Reliability First Corporation (RFC) and SERC Reliability Corporation (SERC). These two regions also contain a large percentage of very old (45 years plus) coal plants, as seen in Exhibit 3 below.

Exhibit 3: Coal Capacity by Age and NERC Region in the Eastern Interconnection



Source: EPA, NEEDS v4.10_MATS

Of the 269 GW of U.S. coal capacity in the EI, roughly one-third is located in just five states: Indiana, Illinois, Ohio, Pennsylvania, and West Virginia. By 2015, the average age of the coal units in these five states will be nearly 50 years (See Exhibit 4). These plants mostly rely on bituminous and sub-bituminous coals. The average full load heat rates in these plants are affected by a host of factors including the age, size, fuel, technical configuration, and environmental controls of the plant.

By 2015, roughly half of the coal units in the EI will be 50 years of age or older. However, given that the older units tend to be smaller in size, they still represent only 25% of the total capacity. Furthermore, the older units also tend to be the ones without emissions controls. Exhibit 5 illustrates the relationship between coal units age, capacity and SO_2 control status.

Exhibit 4: State Level Coal Unit Summary

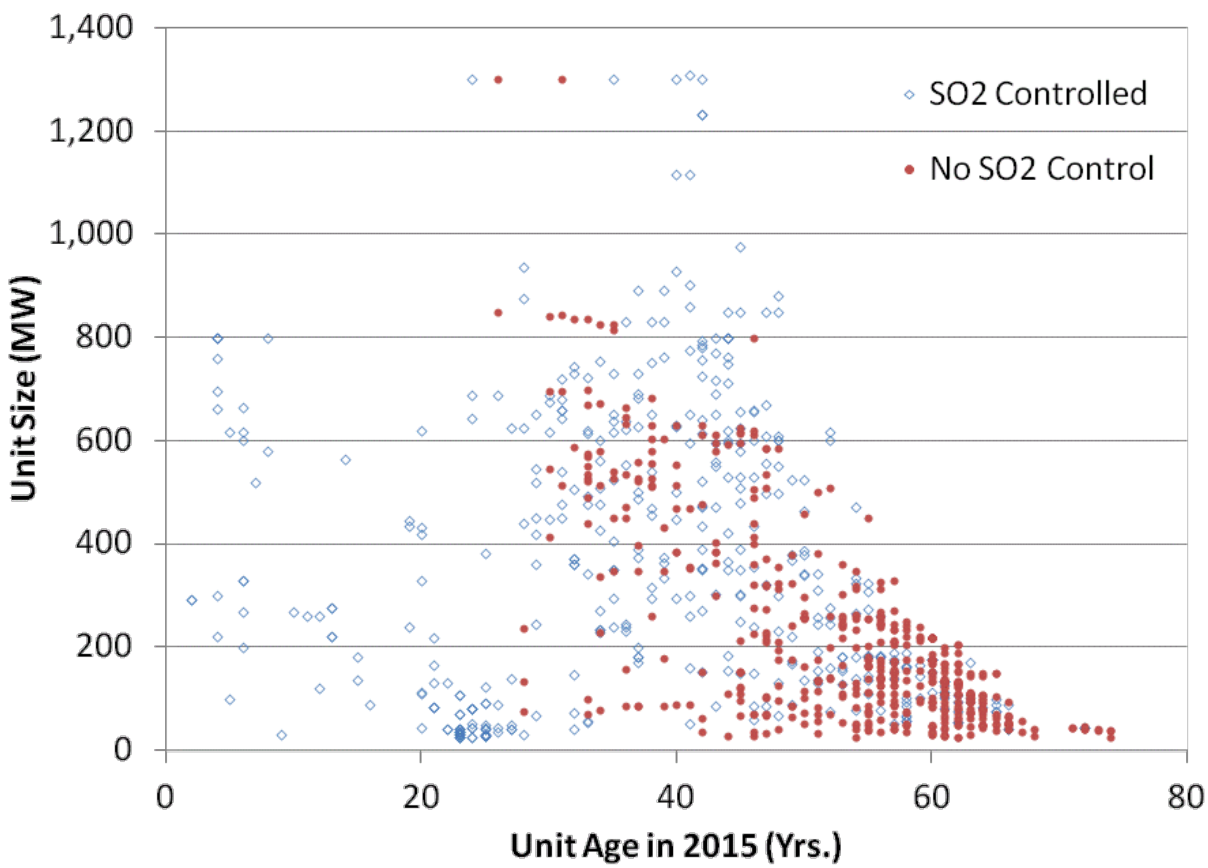
State	# of Coal-Fired Units	Coal-Fired Capacity (GW)	Fuel Source Composition	Average Age in 2015 (Years)
Alabama	39	11.5	Bit. & SubBit.	52

Arkansas	6	4.5	SubBit.	29
Connecticut	3	0.6	Bit.	32
Delaware	5	0.8	Bit.	43
Florida	31	10.6	Bit. & SubBit.	36
Georgia	32	13.1	Bit. & SubBit.	48
Illinois	57	17.2	Bit. & SubBit.	48
Indiana	73	19.4	Bit. & SubBit.	49
Iowa	46	6.4	Bit. & SubBit.	54
Kansas	17	5.2	Bit. & SubBit.	44
Kentucky	56	15.2	Bit. & SubBit.	45
Louisiana	12	4.4	Bit., SubBit., & Lignite	32
Maine	2	0.1	Bit.	25
Maryland	16	4.9	Bit. & SubBit.	48
Massachusetts	7	1.6	Bit.	55
Michigan	62	11.6	Bit. & SubBit.	52
Minnesota	31	5.1	Bit. & SubBit.	51
Mississippi	10	2.6	Bit., SubBit., & Lignite	36
Missouri	50	11.5	Bit. & SubBit.	50
Montana	1	0.1	SubBit. & Lignite	57
Nebraska	17	4.1	SubBit.	41
New Hampshire	4	0.5	Bit.	56
New Jersey	10	2.1	Bit. & SubBit.	43
New York	30	2.7	Bit. & SubBit.	44
North Carolina	62	13.4	Bit. & SubBit.	46
North Dakota	14	4.2	SubBit. & Lignite	38
Ohio	92	21.9	Bit. & SubBit.	54
Oklahoma	14	5.3	Bit. & SubBit.	31
Pennsylvania	75	18.1	Bit. & SubBit.	46
South Carolina	32	7.2	Bit.	44
South Dakota	1	0.5	SubBit.	40

Tennessee	33	8.4	Bit. & SubBit.	58
Texas	9	4.4	SubBit. & Lignite	34
Virginia	56	6.3	Bit.	38
West Virginia	41	15.3	Bit. & SubBit.	47
Wisconsin	53	8.6	Bit. & SubBit.	45
Total EI	1,099	269.4		44

Source: EPA, NEEDS v4.10_MATS

Exhibit 5: Coal Units Greater than 25 MW in the Eastern Interconnection



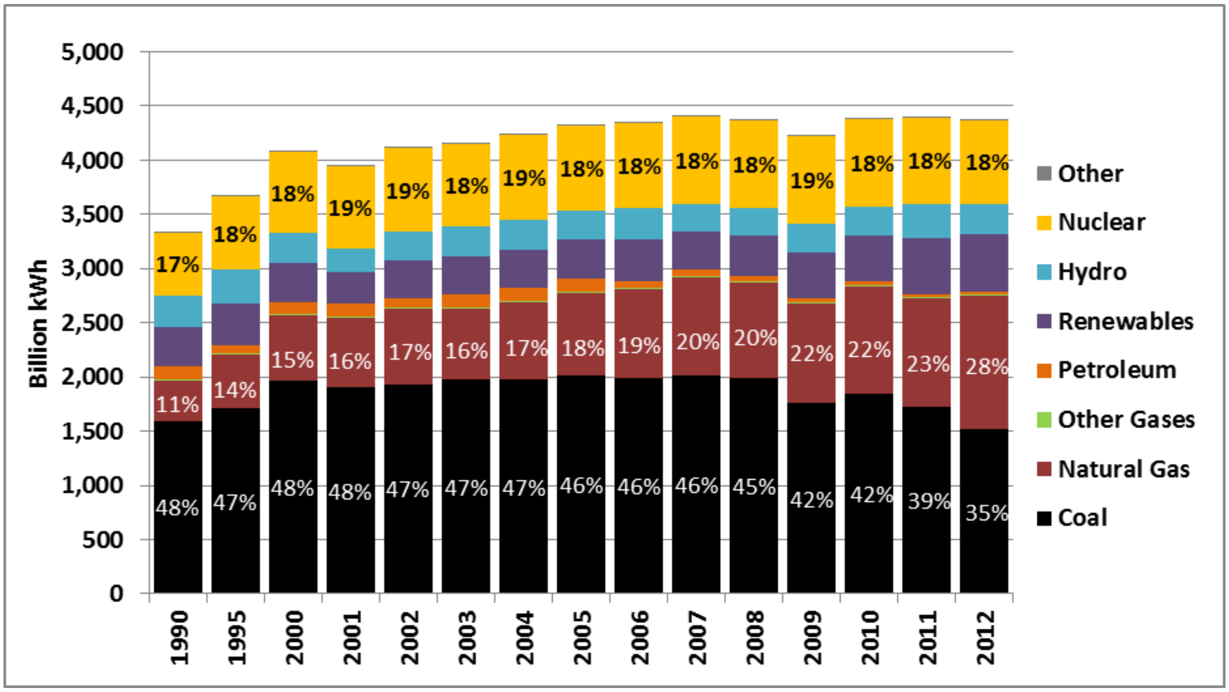
Source: EPA, NEEDS v4.10_MATS

The majority of units without SO_2 controls (red circles) will be older than 50 years by 2015, and most have less than 300 MW of capacity, while the newest units (25 years and under) are controlled for SO_2 due to New Source Performance Standards (NSPS). Units between these two groups are largely mixed. Units that are 50 years or older and uncontrolled for SO_2 represent the subset of units with the highest risk of retirement due to the upcoming coal regulations.

1.2 Historical and Current Fuel Mix for the Eastern Interconnect and the U.S.

Over the past 30 years, the national fuel mix has undergone a gradual shift from coal accounting for over half of total generation to a more diverse mix of fuels – see Exhibit 6 below.

Exhibit 6: National Historical Fuel Mix



Source: EIA, Annual Energy Review, September 2012; EIA, Electric Power Monthly[2]

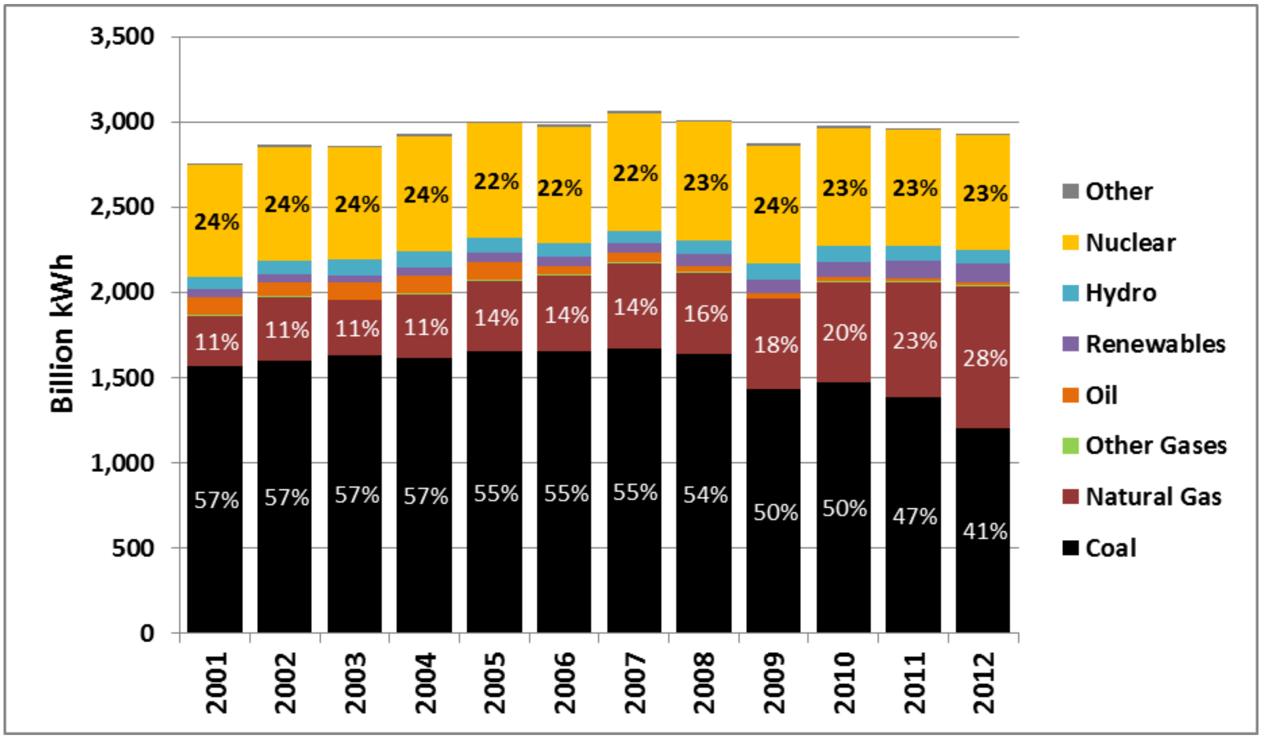
This trend is even more apparent in the EI, as coal generation that routinely accounted for more than 60% of total generation over the past 30 years is now at 41% in 2012—see Exhibit 7. This shift was largely driven by an increase in natural gas development, particularly in recent years due to significant increase in production from shale gas. In general, the share of coal in the EI has been higher than that in the national fuel mix.

Over the same time period (1980-2010), the share of generation from natural gas-fired units in the EI has increased from 10% to 20%, and the share of generation from nuclear units has increased from 14% to 23%. National share of gas is higher than the EI, where nuclear share in the EI is higher compared to national level mix. The total nuclear generation has continued to increase due to uprates at existing facilities, even though the last nuclear units came online in the 1980s. Although total generation from nuclear units has increased in recent years, it is not

[2] The EIA's monthly electric power generation data only started including both utility and non-utility data from 1989 and on. Therefore, to provide a fair comparison, the chart shows total generation from all sectors in the U.S. from 1990 onwards to illustrate changes in generation fuel mix at a national level.

keeping pace with demand growth, and the share of nuclear power as part of the generation mix has begun to erode.

Exhibit 7: Historical Generation Fuel Mix in the Eastern Interconnection



Source: EIA, Electric Power Monthly[3]

1.3 Estimates of Historic and Future Coal Demand

On a global level, coal consumption has been increasing for the last three decades, with higher rates of growth in the most recent decade. Total coal consumption more than doubled from 69.9 quadrillion Btu in 1980 to 151.5 quadrillion Btu in 2010—see Exhibit 8 and Exhibit 10. The U.S. was the largest coal consuming country until the late 1980s when China surpassed the U.S. in coal consumption. However, total coal demand in the U.S. still remains a significant portion of the world's total consumption.

Coal accounted for 28% of total world energy consumption in 2008, and was mainly used by power producers (60%) and industrial consumers (36%).[4] In the U.S. the electric sector coal

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[3] From 2001 and on, the EIA started including utility and non-utility data in one single file, where generation data can be broken down by NERC region. Prior to 2001, utility and non-utility data were recorded in separate files, and NERC region was not clearly indicated for non-utility generating resources. Therefore, only generation data from all sectors in the Eastern Interconnection is displayed from 2001 onwards.

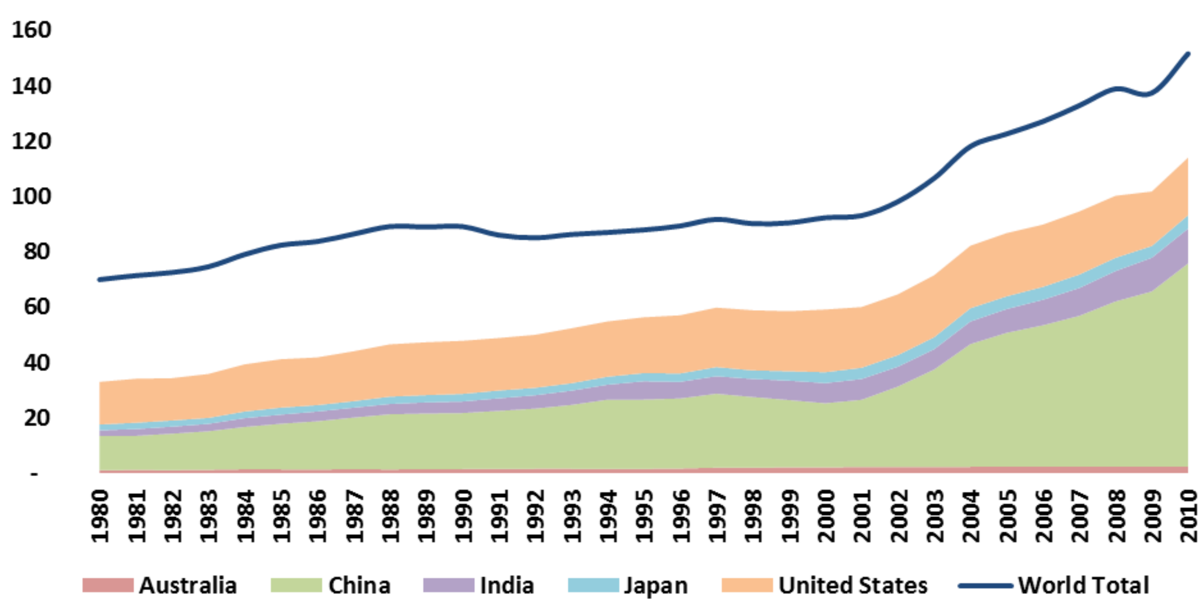
[4] EIA, International Energy Outlook 2011, Coal. http://www.eia.gov/forecasts/ieo/coal.cfm

burn accounts for more than 90% of all coal usage. In 2011, the U.S. consumed 1 billion tons of coal, produced 1.09 billion tons, and exported 106 million tons abroad. 92% of total coal produced is steam coal suitable for electricity generation, while 8% is metallurgical coal for steel-making. Steam coal can be further characterized as bituminous coal (45% of U.S. production), subbituminous coal (47%), and lignite coal (7%).

The average annual growth rate of coal consumption in the U.S. from 1980 to 2005 was 1.6%, whereafter coal consumption in the U.S. began to decline. After 2005, the U.S. witnessed a gradual decrease in coal demand, with a particularly sharp dip in 2009 in the midst of the global financial crisis. Developed countries, such as Japan, Australia and Germany, also displayed a similar patterns in their coal consumption. On the other hand, developing countries have continued their upward trend in coal consumption despite the world economic downturn. China is far and way the main contributor to the steep rate of global coal consumption since early 2000s. While their consumption escalated at an annual average rate of 3.6% between 1980 and 1999, between 2000 and 2010, the annual average growth rate in China more than tripled to 12.2%.

Driven by rising international demand, U.S. coal exports are expected to further increase from the current 100 million tons. West Coast port developers are planning expansions of existing ports and construction of new terminals for shipping up to 80 million tons of PRB coal to Asia. East Coast planned port expansions could support exports of up to 100 million tons a year, while Gulf and Southern proposed port expansions could provide capacity up to 90 million tons a year.

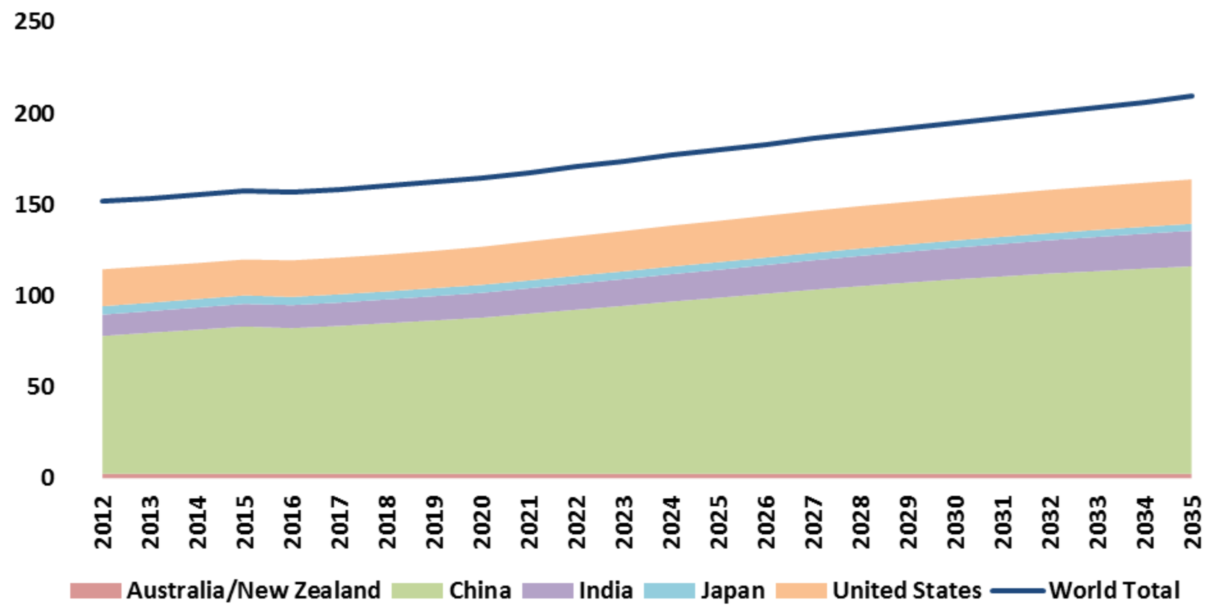
Exhibit 8: Historic coal consumption 1980 – 2010 (quadrillion Btu)



Source: EIA, International Energy Statistics

The major factor affecting coal consumption going forward is the rate of economic growth. The EIA provides a range of scenarios when projecting world coal consumption from 2012 to 2035. In this report, ICF presents the EIA's reference case, which is also known as the baseline world economic growth case—see Exhibit 9 and Exhibit 11. The EIA projections assume that the world will sustain a 3.5% economic growth rate until 2015, before decreasing to 3.3% after 2015.

Exhibit 9: Projected world coal consumption 2012 – 2035 (quadrillion Btu)



Source: EIA, International Energy Outlook 2011

In the U.S, coal's share of total energy consumption for electrical generation is expected to decline over time, due to a) the large amount of shale gas being produced, and b) the more stringent environmental regulations concerning air emissions that are likely to result in increased retirements of existing coal-fired power plants. These factors, along with weaker economic growth rates, lead the EIA to project that the annual average growth rate for coal consumption will be 0.8% between 2012 and 2035 in the U.S.

Other key regions of the world exhibit a different pattern in coal consumption. China's coal consumption is projected to grow at 1.8% a year for 2012 through 2035. More than half of China's coal is used for power and heat generation[5], while industries such as steel and construction accounted for 30 percent of coal use in 2011. With China expected to remain as the leading global producer of steel and manufactured goods, demand for coal will be sustained

[5] EIA, http://www.eia.gov/countries/cab.cfm?fips=CH

at a high level, despite expected increases in economic efficiency which will offset the consumption per unit of GDP.[6]

Elsewhere, Central and South America have projected annual growth rates of 4%, which is the highest among all regions, but the nominal level of consumption will only be 1.4% of China's consumption in 2035. Finally, developed countries in Europe and Asia are expected to experience negative growth rates in demand resulting from large scale retirements of coal plants and continued transition to alternative energy sources.

Exhibit 10: Historic world coal consumption 1980 – 2010 (quadrillion Btu)

	1980	1985	1990	1995	2000	2005	2010
Australia	1.1	1.3	1.4	1.5	2.1	2.3	2.3
China	12.3	16.5	20.3	25.0	23.1	48.3	73.5
India	2.1	3.3	4.2	6.6	7.3	8.6	12.6
Japan	2.1	2.5	2.7	3.0	3.9	4.6	4.8
United States	15.4	17.5	19.2	20.1	22.6	22.8	20.8
World Total	69.9	82.4	89.1	87.9	92.3	122.5	151.5

Source: EIA, International Energy Statistics

Exhibit 11: Projected world coal consumption 2012 – 2035 (quadrillion Btu)

	2012	2015	2020	2025	2030	2035
Australia/New Zealand	2.5	2.5	2.5	2.5	2.5	2.5
China	75.5	80.7	85.5	96.4	106.5	113.6
India	11.7	12.4	13.6	15.3	17.3	19.5
Japan	4.6	4.6	4.4	4.2	4.0	3.8
United States	20.2	19.7	20.8	22.6	23.4	24.3
World Total	151.5	157.3	164.6	179.7	194.7	209.1

Source: EIA, International Energy Outlook 2011

1.4 Historic and Forecast Cost of Coal-fired Electricity Generation

The cost of generation from coal-fired units is driven by the delivered price of coal and variable operation and maintenance expenses due to operation of the facility and any installed emissions controls. Of these components, the delivered price of coal is by far the largest driver of the overall cost of coal-fired generation.

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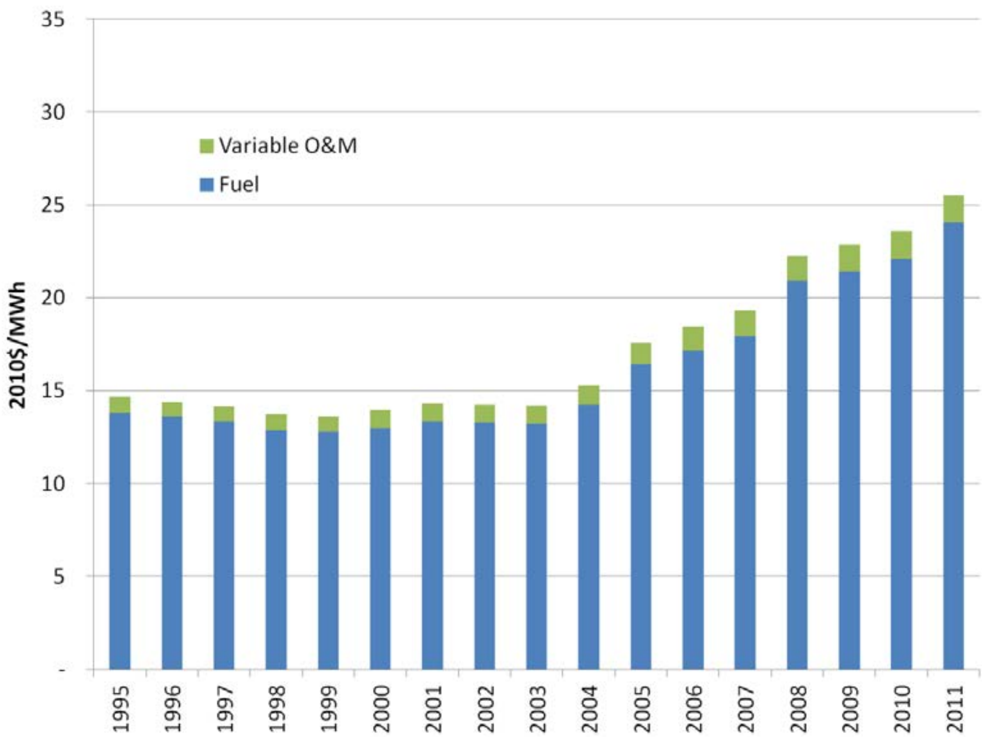
[6] BP Energy Outlook 2030, 2012. http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/O/2012_2030_energy_outlook_booklet.pdf

Between 1995 and 2010, the cost of generation from fossil steam units increased over 60%, from $15/MWh to $24/MWh (in constant 2010$)—see Exhibit 12. The increase in cost was largely driven by increasing coal prices. 93% of the $9/MWh increase in the cost of coal-fired generation from 1995 to 2010 is due to the increase in the cost of delivered coal.

Exhibit 12: Historical Cost of Fossil Steam Generation in the Eastern Interconnection

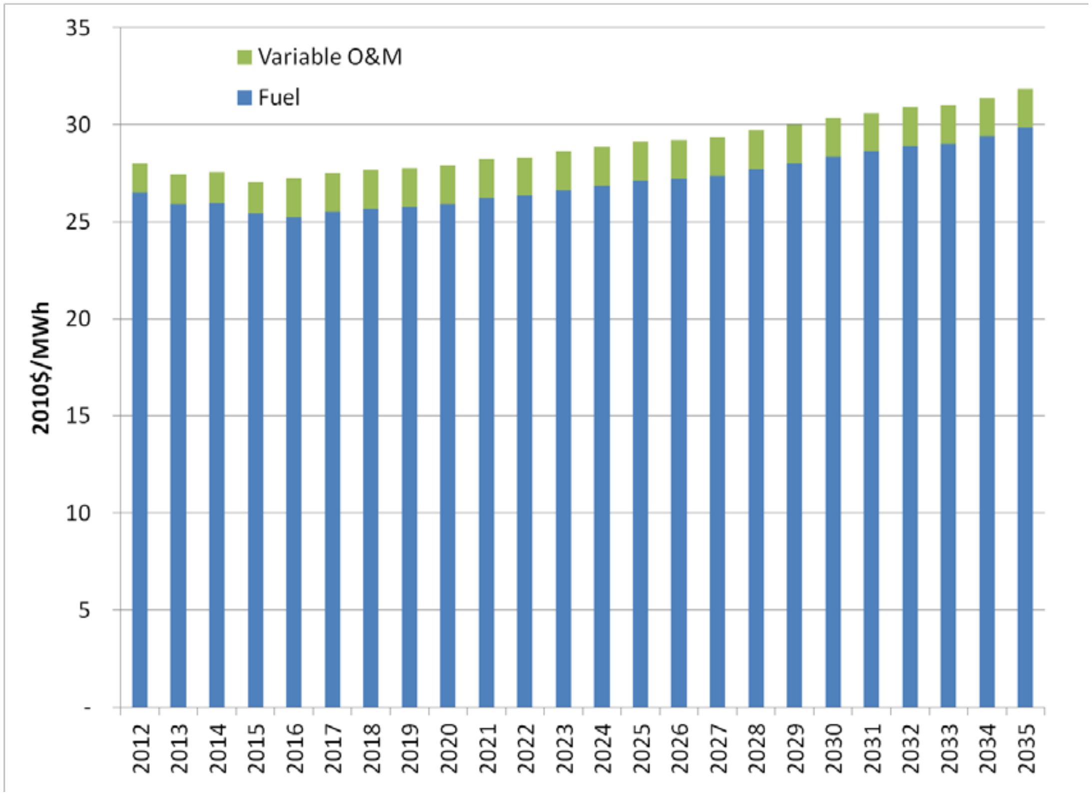


Source: Federal Energy Regulatory Commission, FERC Form 1, 'Annual Report of Major Electric Utilities, Licensees and Others via Ventyx Global Energy Velocity Suite

Using projections from the EIA's Annual Energy Outlook (AEO) 2012, ICF calculated the average delivered coal costs to various EI regions. Going forward, the cost of coal-fired generation will continue to largely be driven by the delivered cost of coal. Upcoming environmental regulations will lead to small increases in variable operations and maintenance (VO&M) costs, with installation of pollution controls on uncontrolled units and additional generation from controlled units. As older, less efficient (higher heat rate) units retire in the coming years, increased generation from more efficient (lower heat rate) units will offset some of the cost increases.

While the cost of delivered coal is expected to decrease slightly through 2016 (according to the EIA projections), delivered coal costs beyond 2016 are projected to increase nearly 20% from 2017 to 2035. This results in higher cost for coal-fired generation over time – see Exhibit 13.

Exhibit 13: Forecasted Cost of Fossil Steam Generation in the Eastern Interconnection



Source: EIA Annual Energy Outlook 2012

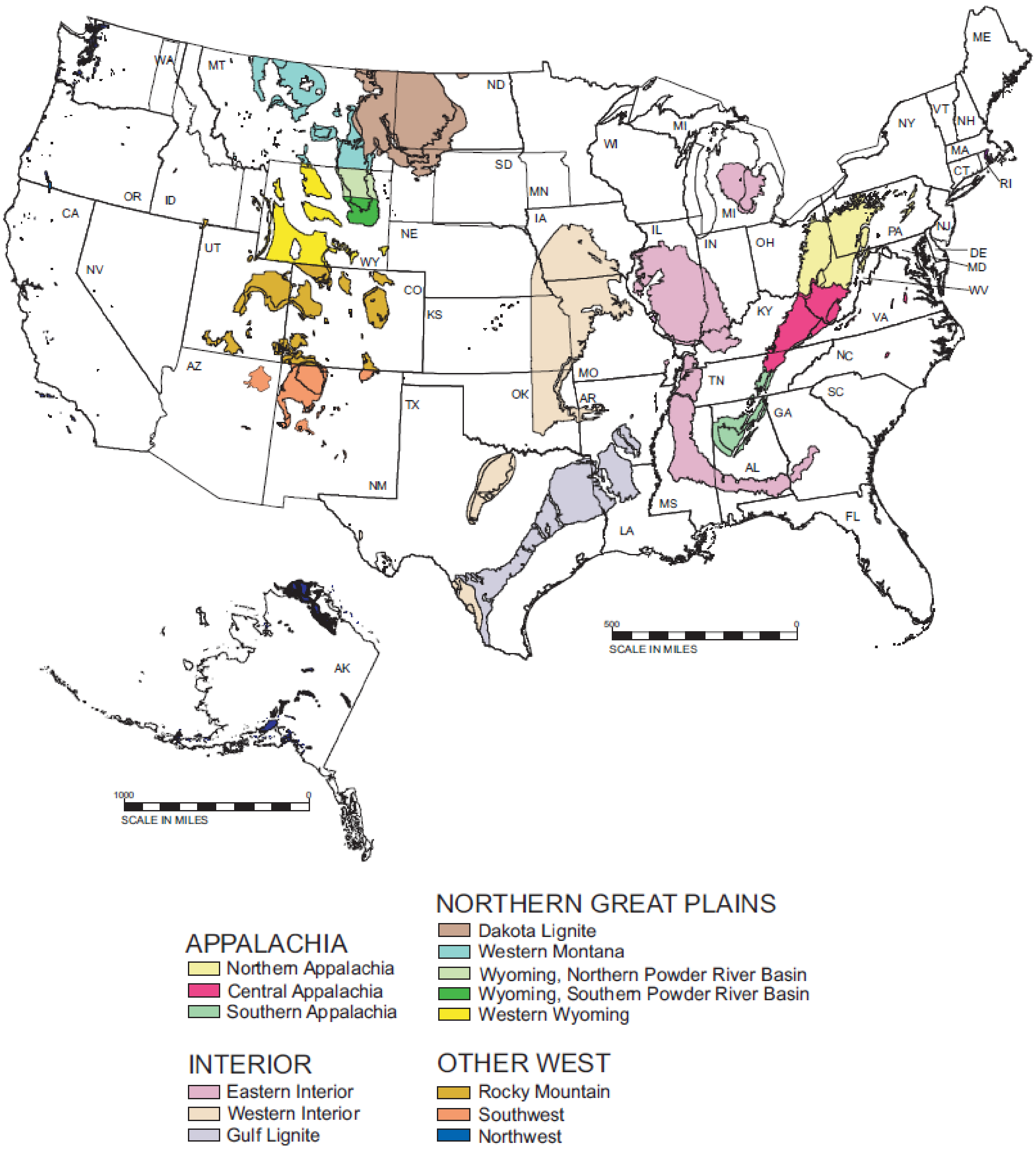
1.5 Estimates of Coal Reserves

Deposits of coal occur in isolated or circumscribed formations, called coal basins. The major coal basins in the U.S. include Northern Appalachia Basin, Central Appalachia Basin, Illinois Basin, and Powder River Basin—see Exhibit 14. The Powder River Basin in the western U.S. has the largest amount of subbituminous coal reserves, while the Illinois Basin has the largest amount of bituminous coal reserves.

Globally, the World Energy Council estimated that at the end of 2009 the total proved reserves are 826 million tonnes, or 910 million tons.[7] Proved reserves of coal are quantities that can be recovered in the future with reasonable certainty from known deposits under existing economic and operating conditions. U.S. has the largest coal reserves, followed by Russia and China.

[7] BP Statistical Review of World Energy, 2010 http://www.bp.com/liveassets/bp_internet/globalbp/globalbp_uk_english/reports_and_publications/statistical_energy_review_2008/STAGING/local_assets/2010_downloads/statistical_review_of_world_energy_full_report_2010.pdf

Exhibit 14: U.S. Coal Basins



Source: EIA, Office of Integrated and International Energy Analysis

As of January 1, 2010, the EIA estimates there are 486.1 billion tons of coal in the demonstrated reserve base of the U.S., of which 276.9 billion tons are recoverable coal reserves.[8] Recoverable coal reserves represent the quantity of coal that can be mined from coal reserves at producing mines as well as from coal reserves considered technologically and economically mineable with current technology and economic conditions. Improvements in mining methods and new technologies may allow for more of the demonstrated reserve base to be economically mined in the future.

With 276.9 billion tons of recoverable reserves, the U.S. can sustain the current one billion a year production level for about 276 years. Even at the historical high production rate of 1.17 billion tons a year, which was reached in 2008, the expected lifetime of the reserves is longer than 230 years. In addition, the amount of recoverable reserves is not static. It can increase over time when technology advancement make the once geologically difficult reserves become feasible or when higher coal prices make higher cost reserves economic.

There are four major ranks of coal in the U.S.: anthracite, bituminous, subbituminous, and lignite. Bituminous accounts for 45% of the recoverable reserves and is primarily located east of the Mississippi River (See Exhibit 15). 42% of all reserves are subbituminous, which are located exclusively west of the Mississippi River. 12% of reserves are lignite coal, which is also largely located in the Western region. Anthracite is only 1% of the coal mix and is located almost entirely in the state of Pennsylvania. Over 80% of bituminous reserves are found in Illinois, West Virginia, Kentucky, Ohio, Pennsylvania, Colorado, and Indiana (in descending order of reserve quantities). 91% of subbituminous reserves are located in the states of Montana and Wyoming. Lignite reserves are mostly divided between Montana, Texas, and North Dakota. In total, the states of Montana, Wyoming, Illinois, West Virginia, and Kentucky each have greater than 15 billion short tons in recoverable coal reserves.

Exhibit 15: U.S. Recoverable Coal Reserves, January 1, 2010 (million tons)

Region and State	Anthracite	Bituminous	Subbituminous	Lignite	Total
Appalachian					
Alabama	-	2,193	-	804	2,997
Kentucky, Eastern	-	6,282	-	-	6,282
Ohio	-	11,646	-	-	11,646
Pennsylvania	3,169	8,838	-	-	12,007
Virginia	70	986	-	-	1,056
West Virginia	-	19,231	-	-	19,231
Other [1]	-	823	-	-	823

[8] Recoverable reserves at producing mines data of a few states are withheld by the EIA to avoid disclosure, which would add additional 29,738 million tons to the U.S. total recoverable reserves.

Interior					
Illinois	-	39,451	-	-	39,451
Indiana	-	4,591	-	-	4,591
Kentucky, Western	-	9,476	-	-	9,476
Missouri	-	3,845	-	-	3,845
Oklahoma	-	817	-	-	817
Texas	-	-	-	10,077	10,077
Other [2]	58	2,098	-	233	2,389
Western					
Colorado	-	4,993	2,281	2,589	9,862
Montana	-	889	64,698	10,032	75,618
New Mexico	-	2,166	5,055	-	7,221
North Dakota	-	-	-	7,993	7,993
Utah	-	2,822	-	-	2,822
Wyoming	-	3,139	41,755	-	44,894
Other [3]	-	486	3,113	195	3,794
U.S. Total	3,298	124,771	116,901	31,922	276,892
[1]Georgia, Maryland, North Carolina, and Tennessee.					
[2]Arkansas, Kansas, Louisiana, Michigan, Mississippi, and Iowa					
[3]Alaska, Arizona, Idaho, Oregon, South Dakota, and Washington					

Source: ICF Analysis of EIA Coal Reserves Data

Characteristics of U.S. coal reserves by region are based on those of coal mined from the same regions, and distributed domestically for coal-fired generation in 2010, available from the EIA's Form 923 data—see Exhibit 16. High quality bituminous coal distributed for steel-making as is anthracite coal, as they are not used for electricity generation. The quantity-weighted average heat content is 23.9 MMBtu/ton for bituminous coal, 17.4 MMBtu/ton for subbituminous coal, and 12.9 MMBtu/ton for lignite coal. On average bituminous coal has 1.9% sulfur, subbituminous coal 0.3% sulfur, and lignite coal 0.9% sulfur.

Exhibit 16: Characteristics of U.S. Steam Coal, 2010

Region and State	Bituminous		Subbituminous		Lignite	
	Heat MMBtu/Ton	Sulfur %	Heat MMBtu/Ton	Sulfur %	Heat MMBtu/Ton	Sulfur %
Appalachian						
Alabama	24.2	1.5				
Kentucky, Eastern	25.0	1.2				

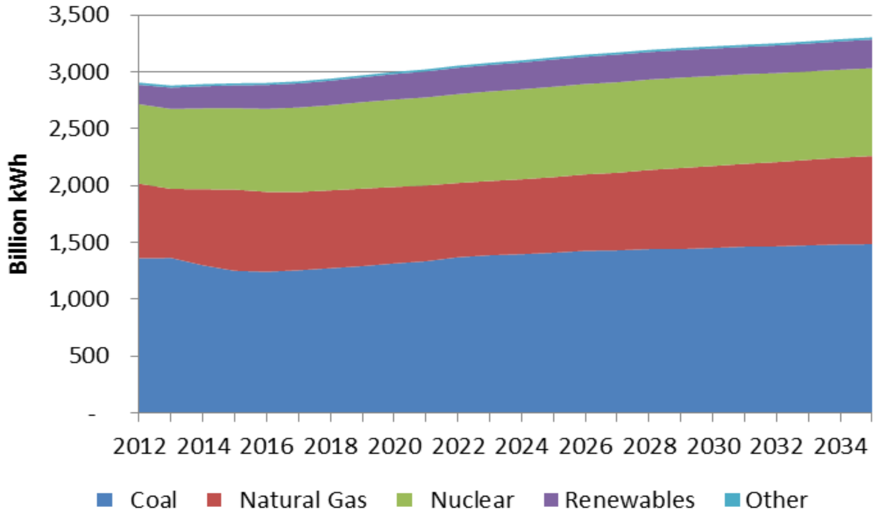
Ohio	24.2	3.6				
Pennsylvania	25.2	2.1				
Virginia	25.4	1.1				
West Virginia	24.7	1.8				
Other [1]	24.1	1.6				
Interior						
Illinois	23.0	2.7				
Indiana	22.4	2.5				
Kentucky, Western	23.2	3.1				
Missouri	21.4	3.6				
Oklahoma	17.4	1.3				
Texas					13.0	1.1
Other [2]	23.1	3.2			12.2	0.6
Western						
Colorado	22.5	0.5	19.9	0.4		
Montana	20.5	0.5	17.8	0.5	13.0	0.5
New Mexico	19.2	0.7	17.8	0.9		
North Dakota					13.0	0.8
Utah	23.0	0.6				
Wyoming	22.6	0.6	17.3	0.3		
Other [3]	21.6	0.6	18.4	0.1		
U.S. Total	23.9	1.9	17.4	0.3	12.9	0.9
[1]Georgia, Maryland, North Carolina, and Tennessee.						
[2]Arkansas, Kansas, Louisiana, Michigan, Mississippi, and Iowa						
[3]Alaska, Arizona, Idaho, Oregon, South Dakota, and Washington						

Source: ICF Analysis of EIA 923 Data

1.6 Future Trends in Generation Mix

The Eastern Interconnection's future capacity mix will be driven by a number of factors – load growth, fuel prices, environmental regulations, technology improvements – that are all subject to significant uncertainties. In order to evaluate the most significant risks and benefits associated with each technology, ICF utilized the assumptions and projections from the Reference Case of the EIA's AEO2012. The AEO2012 Reference Case projects a fairly static view of the EI's generation mix through 2035—see Exhibit 17.

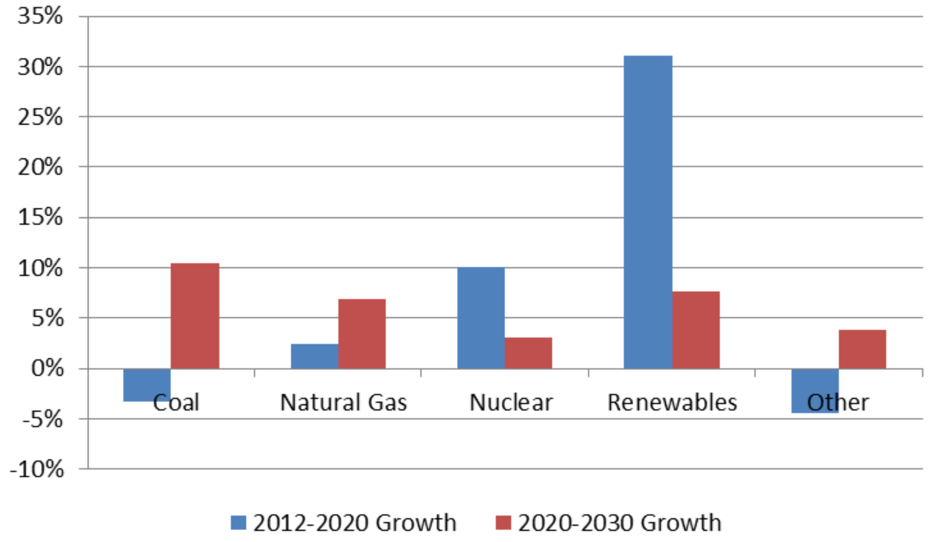
Exhibit 17: Projected Reference Case Generation Mix for the Eastern Interconnection



Source: EIA AEO2012

Despite the relatively stable generation mix, there are some notable trends in the early part of the projection—see Exhibit 18. For example, in the near- to mid-term (2012-2020), nuclear generation increases by 10% of the total generation share, due to several planned facilities coming online. Renewable generationalso increases by 31%, driven both by firmly planned capacity expansion and new builds required to meet state renewable portfolio standard (RPS) goals. During this same timeframe, the rate of increase in natural gas generation becomes somewhat more moderate as natural gas prices rise from their historic lows, while coal generation contracts slightly to reflect retirements driven by gas competition, environmental regulations, and lower power prices.

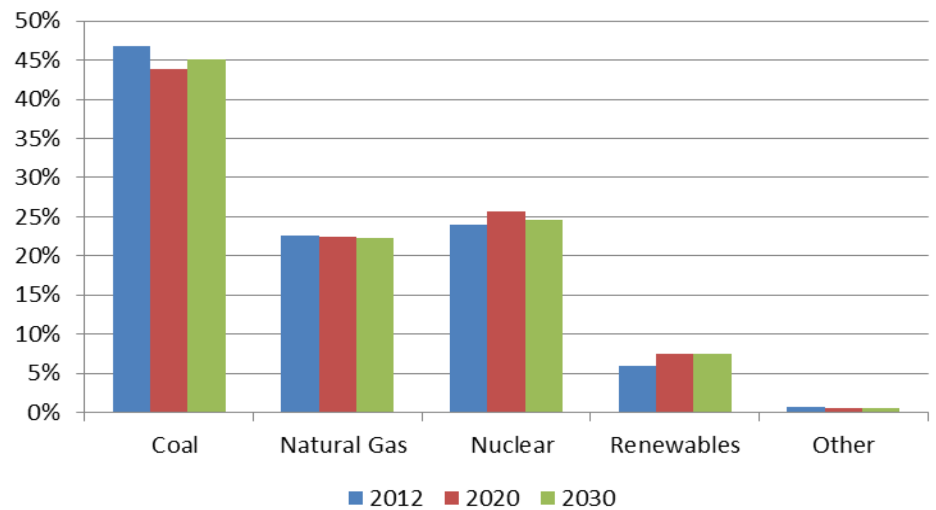
Exhibit 18: Projected Change in Generation for the Eastern Interconnection



Source: EIA AEO2012

Beyond 2020, state RPS goals level out, compliance with environmental regulations leaves behind a newer and more efficient coal fleet, and gas prices continue to rise steadily. The overall effect of these changes in the Reference Case is to largely restore the projected generation mix in 2035 to a profile that is fairly similar to today's power sector—see Exhibit 19.

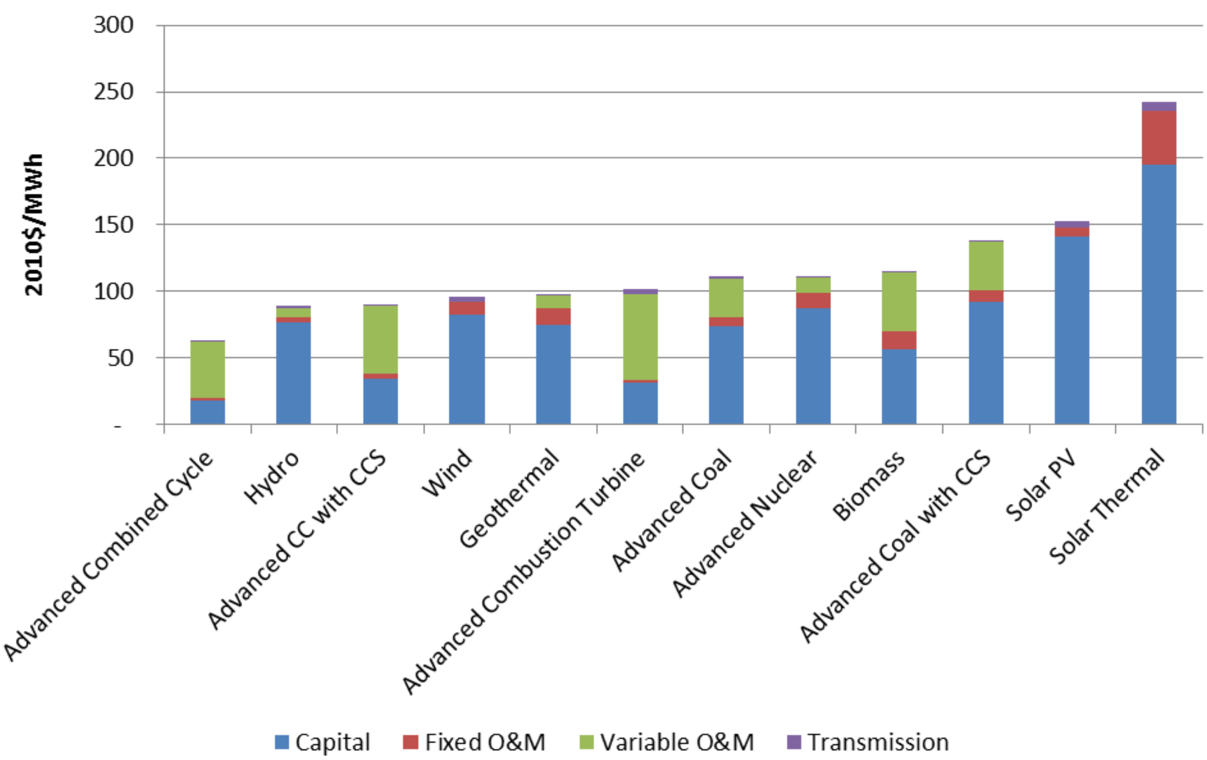
Exhibit 19: Projected Change in Share of Total Eastern Interconnection Generation



Source: EIA AEO2012

To achieve this long-term shift in the EI's generation mix, significant capacity additions will need to occur. This outcome may be spurred through the widespread retirement of existing facilities, increased load growth, or a combination of both factors. The AEO2012 Reference Case does not feature either of these factors –the EIA does not include any proposed environmental regulations (e.g., coal combustion residuals, cooling water intake structures), future GHG charge (e.g., cap and trade), or national incentive for clean technologies to lead a power sector transformation (e.g., clean energy standard). Additionally, the Reference Case assumes a historically low average annual load growth of 0.6% (total generation of the EI is projected to grow at 0.56%/year from 2012-2035), reducing the need for new capacity to meet growing load. The EIA does produce a number of scenarios to the Reference Case, including a High Economic Growth Case that produces more than 40 GW of additional unplanned capacity additions by 2030 and a $25 Carbon Dioxide ($CO_2$) Emission Fee Case that produces approximately 80 additional GW of renewable builds and 73 GW of new nuclear capacity. Returning to the Reference Case, however, the unplanned capacity additions that are projected consist of natural gas facilities and renewable projects. This is largely a function of the EIA's cost assumptions, as shown in Exhibit 20.

Exhibit 20: Estimated Levelized Cost of New Generation Resources in 2017



Source: EIA AEO2012

The levelized costs above represent the EIA's view on the relative costs of the major generation technologies at a specific point in time (2017). However, underpinning this view are a number of market, technical, and regulatory assumptions that do not capture the full range of risks and benefits that will ultimately impact the future success of each technology type. The exhibit below is an attempt to provide a fuller account of the key benefits and challenges facing each technology, as well as the risk that technology poses to future coal dispatch.

Exhibit 21: Summary Of Benefits and Challenges For Each Major Technology Type

Technology	Benefits	Challenges	Risk to Coal Dispatch
Hydroelectric	Emissions-free baseload resource. Pumped storage may be utilized to manage demand differentials between peak and off-peak hours, improving system efficiency.	Environmental issues associated with dam building have relegated new hydroelectric projects largely to incremental capacity improvements at existing facilities and smaller, run-of-river facilities. Large hydropower potential in the U.S. are almost fully utilized already. Actual power generation is sensitive to precipitation levels and surface runoff.	**Low risk to coal dispatch** due to unavailability of, and restrictions on, new, large scale, hydroelectric projects.
Natural Gas	Combined cycle units are a mature technology with relatively small lead-times, low project risk, and low capital cost, making new combined cycle facilities particularly attractive in unregulated markets. Projected low gas prices make new gas plants, as well as refiring of existing coal plants with gas a strong possibility. Combustion turbines can be easily sited for capacity needs and may play a key role in firming and integrating renewable builds with the power system. Natural gas tends to produces fewer emissions, less water use, and fewer waste products than coal facilities.	Gas prices have historically been volatile, raising fuel diversity as a concern in gas-reliant markets and regions. As a fossil fuel-fired resource, natural gas has exposure to GHG price risk (but less than coal). In a clean energy standard context, gas may or may not be treated as a qualifying resource, depending on the proposal.	**High risk to coal dispatch**. Natural gas has significant cost and non-cost advantages over coal as a new baseload resource, given today's market, regulatory, and technical context.
Nuclear	Low variable cost, zero-emission baseload resource. No exposure to GHG price risk; little exposure to fuel price risk for uranium. Currently receives significant financial support from state and federal government	High capital cost, significant upfront costs, long lead times, and a history of cost overruns are some of the elements that create the significant project risk for new nuclear projects. Public concerns regarding the safety of nuclear facilities – e.g., widespread tritium leaks[9], San Onofre's	**Medium risk to coal dispatch.** Without significant improvement in the capital cost of new nuclear units, widespread deployment is

[9] http://www.ap.org/company/awards/part-ii-aging-nukes

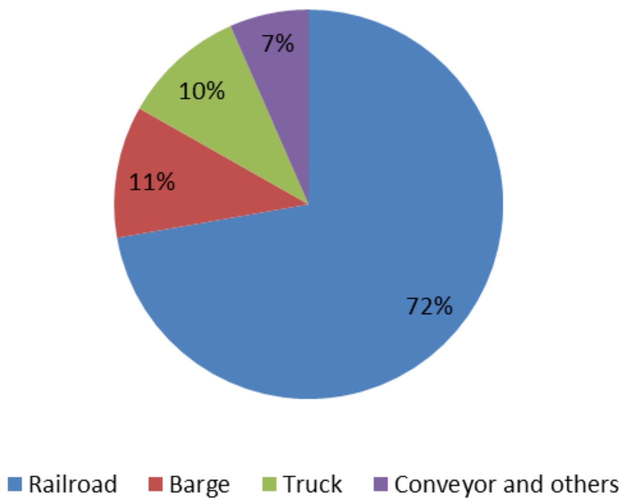
	(production tax credit, loan guarantees, research and development funding, etc.). Positioned as a qualifying resource for any eventual clean energy standard legislation. Nuclear also has a consistently low dispatch cost that provide a valuable hedge against the impact of future market and regulatory uncertainities	unexpected outage over damaged tubes, concerns over waste disposal, etc. – continue to bog down the industry. The bulk of the existing nuclear was built in the 1960s and 1970s and is currently facing the expiration of their license extensions (20-year extension after the initial 40-year license), casting doubt on the role of nuclear in the long-term national generation profile.	unlikely without significant regulatory support (GHG cap and trade program, clean energy standard, etc.) and/or higher power prices.
Wind	Wind is an emissions-free resource that currently enjoys regulatory support through a variety of sources, including renewable portfolio standards, the production tax credit, accelerated depreciation, and loan guarantees. Recent turbine technology improvements have led to higher realized capacity factors – particularly in lower-resource areas. This trend bodes well for project viability and may allow development in previously marginal wind areas with better access to major load centers. There is no fuel cost risk associated with wind projects, upfront costs are low, and capital costs have declined in recent years.	Wind is still several years away from grid parity in most United States markets. Wind continues to rely on regulatory support measures, such as the federal production tax credit and state renewable energy credit (REC) markets. Regulatory support may ebb and flow with costs (e.g., low power prices necessitating higher REC prices) and prevailing political philosophies—e.g., currently, the wind market is projected to experience a very soft year in 2013 due in large part to the uncertain fate of the production tax credit. Despite improvements in operations, the intermittent nature of wind, siting availability/restrictions, non-peak coincidence, low power prices, and transmission costs remain as obstacles to wider wind deployment in certain markets. While storage and gas backup are two widely discussed options to address some of wind's relative shortcomings, these options are expensive, making wind even less competitive without generous regulatory support. Offshore wind has yet to achieve significant success in North America due to its higher expenses and public resistance, which have derailed the development of several proposed offshore wind facilities.	**Low risk to coal dispatch** due to intermittent nature, high costs, and resource separation from major load centers. However, a robust turnaround for the wind market spurred by extension of the PTC, higher power prices, more transmission linkages, and continued technology improvements could pose a risk to marginal coal units.

Solar	Solar enjoys considerable regulatory support in the form of renewable portfolio standards (generally and through solar carve-outs), the investment tax credit, accelerated depreciation, loan guarantees, and other incentives. Solar photovoltaic costs have decreased dramatically in the past few years.	Although capital costs for solar photovoltaic have decreased sharply, widespread grid parity in the EI is still a relatively longer-term proposition. Resources for new solar projects remain generally poor in the EI, with certain exceptions, leaving the near-term growth of solar dependent on the availability and generosity of various incentives. The capital cost decline of solar projects will determine its long-term prospects for large-scale solar deployment.	**Very low risk to coal dispatch** due to poor overall resource availability, high cost, and intermittent nature.
Biomass	Unlike wind and solar, biomass is a dispatchable, baseload renewable resource. Biomass enjoys considerable regulatory support in the form of renewable portfolio standards, the production tax credit, accelerated depreciation, loan guarantees, and other incentives. Biomass is currently treated as a carbon neutral fuel – as such, the potential exists for co-firing of biomass in coal boilers to achieve emission reductions.	There is significant fuel risk with any dedicated biomass facility. The low heat content of biomass makes transport over even intermediate distances economically infeasible, while requiring an extremely large dedicated fuel supply for larger facilities. The carbon neutrality of biomass is currently under review by the EPA to determine the necessity of a Clean Air Act permit for biomass plants, which could lead to higher costs.	**Very low risk to coal dispatch** due to smaller size, specific locational requirements, higher cost, and significant fuel risk.
Geothermal	Non-emitting, baseload, dispatchable, renewable resource. Geothermal units may run at high capacity factors for low cost.	Potential site locations are both limited and uncertain – current geothermal sites may not remain continuous sources of heat. The initial drilling costs are expensive and feasible sites for new geothermal power plants are located almost exclusively outside of the EI region.	**Very low risk to coal dispatch** due to specific locational requirements and lack of resource in the EI.

1.7 Coal Transportation

Coal is transported from coal mines to end users primarily by rail, barge, truck, and vessel depending on geography and infrastructure conditions, distances between origins and destinations, and transport costs among other factors. In 2010, 72% of U.S. coal consumed domestically is distributed by railroad, 11% by barge, 10% via truck, and the remaining 7% via conveyors and other transport modes. Aside from domestic consumption, 8% of U.S. coal production in 2010 was exported, predominantly by seaborne vessels.

Exhibit 22: Domestic U.S. Coal Transportation Options



Source: EIA, Quaterly Cumulative Data

Railroads transport significantly more coal than all other transportation methods combined, however, rail infrastructure varies from one region to another. While the western U.S. heavily depends on rails to transport coal from the Powder River Basin, in the east, railroads face more competition from barges and trucks, as there are more carriers involved. Power plants and coal mines served by rail can negotiate better rates if there is a competing carrier or an alternative transportation mode they can use. Those that are captive to a single carrier or mode tend to get higher, less negotiable rates, as barges generally offer the least expensive transportation rates, and facilities that have access to barge shipment for a part of their shipping distance can lower transportation costs. However, since they can rarely make the entire trip due to waterway limitations, barges often pair with trucks or rail transportation in the east.

The economics around coal delivery vary between coal basins. As the biggest coal producing basin in the U.S., the Powder River Basin (PRB) heavily relies on railroads to carry its coal out of the basin. There is a joint railway line owned by the BNSF Railway and the Union pacific Railroad running through the southern section of the basin, serving ten major coal mines on the line. The joint line was considered a bottleneck of the PRB coal supply in the early 2000s as its capacity barely kept up with the growth of coal volumes. In 2005 and 2006, the joint line experienced substantial derailments, curtailing more than 10% of the loading at mines and causing chaos at PRB coal-burning power plants. Since then, substantial investment in new track and rail cars by BNSF and Union Pacific have greatly improved the bottleneck for PRB coal rail shipments.

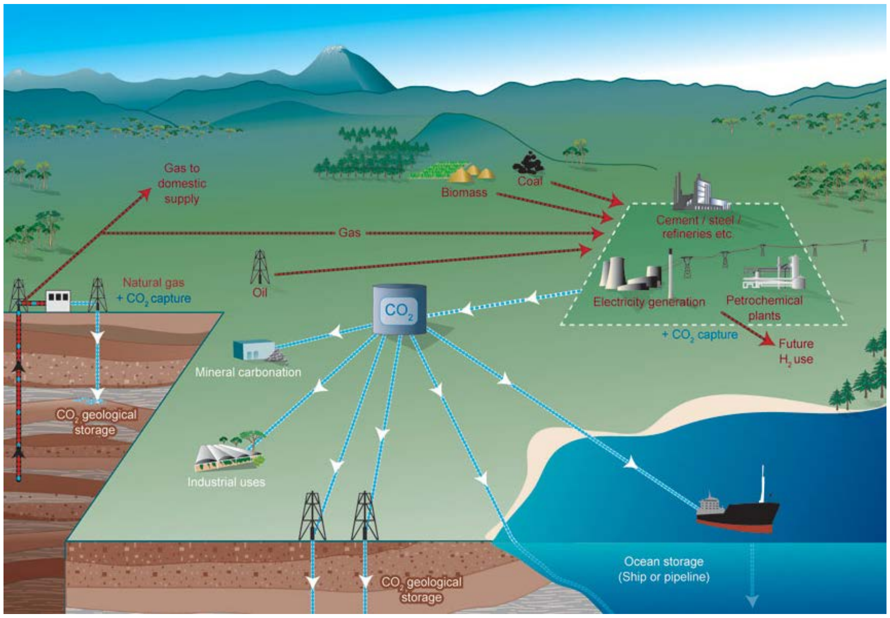
With a longer haul to end-users in the eastern U.S., PRB coal has higher transportation costs than coal from other basins. In January 2012, a representative power plant in the eastern U.S. paid approximately $36/ton for PRB coal when it was priced at $12.5/ton at the minemouth, meaning 65% of the delivered cost was spent on transportation. Though PRB coal costs much less to transport to power plants in the western U.S., its popularity is negatively affected by rail rate and service disputes between power plants and carriers, as many western power plants are captive to a single carrier on all or part of their shipping route from the basin. Many disputes end up at the Surface Transportation Board for final resolution.

The Illinois Basin (ILB), second only to the Powder River Basin in coal output, executes more than 30% of coal traffic via barge shipments, given its proximity to the Great Lakes System. This has allowed ILB coal to expand its market share, as the coal can be shipped through a combination of barge and rail to power plants as far away as Florida. Its low cost coal remains attractive to power plants that traditionally burn low sulfur Central Appalachian Coal or Powder River Basin Coal, as well as those plants that can burn high sulfur coal due to scrubber retrofits.

1.8 CO_2 Pipelines and Geological Storage Background

The key technology for continued use of coal under a policy that is aimed at significant reductions in CO_2 emissions from coal power plants is CO_2 capture and storage (CCS). CCS technology involves three main steps: a) capture and compression of CO_2 from a power plant or other industrial facility; b) transporting the captured CO_2 to a storage site; and c) injecting and safely storing the CO_2 in underground geological reservoirs. Exhibit 23 illustrates the overall technological components of CCS.

Exhibit 23: Illustration of CCS Components[10]



Source: IPCC, 2005

In this section, as required in the Scope of Work, ICF summarizes the information on options for CO_2 storage, with a focus on the EI, existing CO_2 pipelines, and potential CO_2 pipelines. The data is sourced mostly from publicly available information, and in some cases it has been supplemented by internal ICF knowledge.

U.S. CO_2 Storage Potential

The U.S. Department of Energy has compiled an assessment of North American CO_2 geological storage potential. This has been documented in the NATCARB Atlas.[11] NATCARB stands for the National Carbon Sequestration Database and Geographic Information System, which is a geographic information system (GIS)-based tool developed to provide a view of carbon capture and storage (CCS) potential.[12] Supported by U.S. DOE, the information in NATCARB is provided by various entitites, including the seven regional partnerships covering the Lower-48

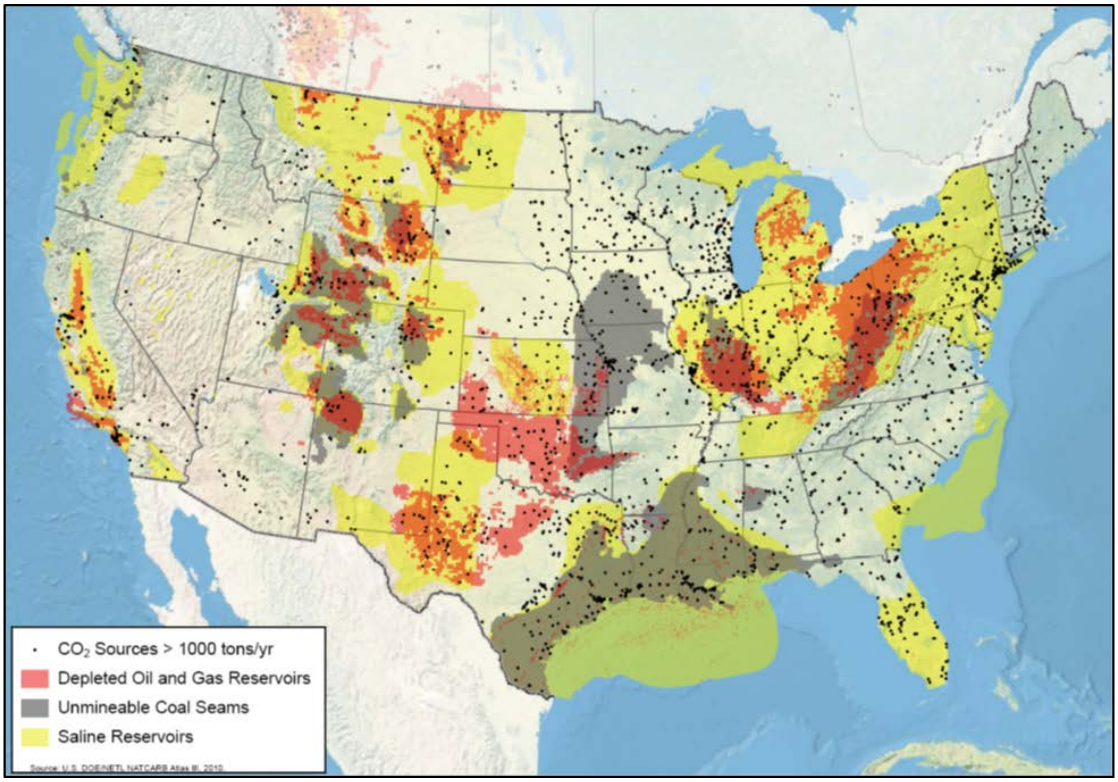
[10] IPCC, 2005, "IPCC Special Report on Carbon Dioxide Capture and Storage," by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

[11] U.S. Department of Energy, 2010, "2010 Carbon Storage Atlas of the United States and Canada (Volume III)," (NATCARB Atlas), DOE Morgantown, WV, http://www.netl.doe.gov/technologies/carbon_seq/natcarb/index.html.

[12] http://www.netl.doe.gov/technologies/carbon_seq/natcarb/index.html

and western Canada.[13] Exhibit 24 is a map showing potential CO_2 storage basins by geologic category (oil and gas, coal, and saline). It also shows major point sources of CO_2 emissions as defined for the atlas (>1,000 tons per year).

Exhibit 24: Map of CO_2 Storage Basins by Type and Major Point Sources



Source: NATCARB GIS database

Exhibit 25 summarizes the results of the regional assessments. Lower-48 total storage potential is 11,087 Gigatonnes (Gt). Almost all of the assessed potential is in saline reservoirs (10,889 Gt) with some potential in depleted fields (109 Gt), CO_2 enhanced oil recovery (17 Gt), and a minor amount in coal beds (73 Gt).

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[13] http://www.netl.doe.gov/technologies/carbon_seq/infrastructure/rcsp.html

Exhibit 25: North America CO_2 Geologic Storage Potential

Gigatonnes Region	Non-EOR Depleted Oil and Gas	CO2 Enhanced Oil Recovery*	Coal Seams Low	 High	 Calc. Midpoint	Saline Formations Low	 High	 Calc. Midpoint	Assessed Total Low	 High	 Calc. Midpoint
Williston Basin and Western Canada	**24.4**	**0.6**	1.0	1.0	**1.0**	165	165	**165**	191	191	**191**
Illinois Basin	**0.9**	**0.1**	1.6	3.3	**2.5**	12	160	**86**	15	164	**89**
Michigan and Appalachia	**16.9**	**0.1**	0.8	1.9	**1.4**	46	183	**115**	64	202	**133**
Gulf Coast, GoM, and Atlantic Offsh.	**28.8**	**3.2**	33.0	75.0	**54.0**	908	12,526	**6,717**	973	12,633	**6,803**
California, Pac. NW, Pac. Offsh., AK	**2.8**	**1.2**	10.0	23.0	**16.5**	82	1,124	**603**	96	1,151	**624**
S. Rockies, Mid-Cont.,West Texas	**51.2**	**10.7**	1.0	2.0	**1.5**	219	3,013	**1,616**	282	3,077	**1,679**
N Rockies, W. Montana	**1.6**	**0.6**	12.0	12.0	**12.0**	221	3,041	**1,631**	235	3,055	**1,645**
North America Total	**126.6**	**16.5**	59.4	118.2	**88.8**	1,653	20,212	**10,933**	1,856	20,473	**11,164**
Alaska	**0.0**	**0.0**	9.0	21.0	**15.0**	0	0	**0**	9	21	**15**
Canada	**18.0**	**0.0**	0.8	0.8	**0.8**	38	51	**44**	57	70	**63**
L48 Total	**108.6**	**16.5**	49.6	96.4	**73.0**	1,614	20,163	10,889	1,790	20,383	**11,087**
onshore	**93.6**	**15.0**	48.3	93.3	**70.8**	1,123	13,407	**7,265**	1,280	13,609	**7,444**
offshore	**15.0**	**1.5**	1.3	3.1	**2.2**	491	6,756	**3,624**	509	6,776	**3,643**

Source: 2010 NATCARB Atlas; ICF estimate (CO_2 EOR)

CO_2-Enhanced Oil Recovery (EOR) storage has a "negative cost" because of the value of the additional crude oil produced. Under a future cap and trade system, the initial storage will occur in areas with CO_2-EOR potential. As shown in Exhibit 25, most of this potential is in West Texas, the Mid-Continent, and the Rockies. Only after this storage potential is exhausted will large volumes be stored in saline reservoirs. The 16.5 Gt of CO_2-EOR potential is an ICF estimate derived from information on U.S. EOR potential by area. The estimate is based on ICF's supply curves of storage economics, by type of storage and geographic area for the U.S.. ICF developed an independent model, called the Geologic Sequestration Cost Analysis Tool (GeoCAT) model, to evaluate the economics associated with injecting and storing for CCS for the entire inventory of U.S. geologic storage potential.

Exhibit 26 shows the breakout of assessed storage potential by state and offshore area. Offshore potential is 3,600 out of 11,000 Gt. Most of the offshore potential is in Gulf of Mexico saline strata. This exhibit was also provided in Excel format. ICF's calculations are compared to the latest NATCARB data in the last column.

Exhibit 26: North America CO_2 Geologic Storage Potential by State

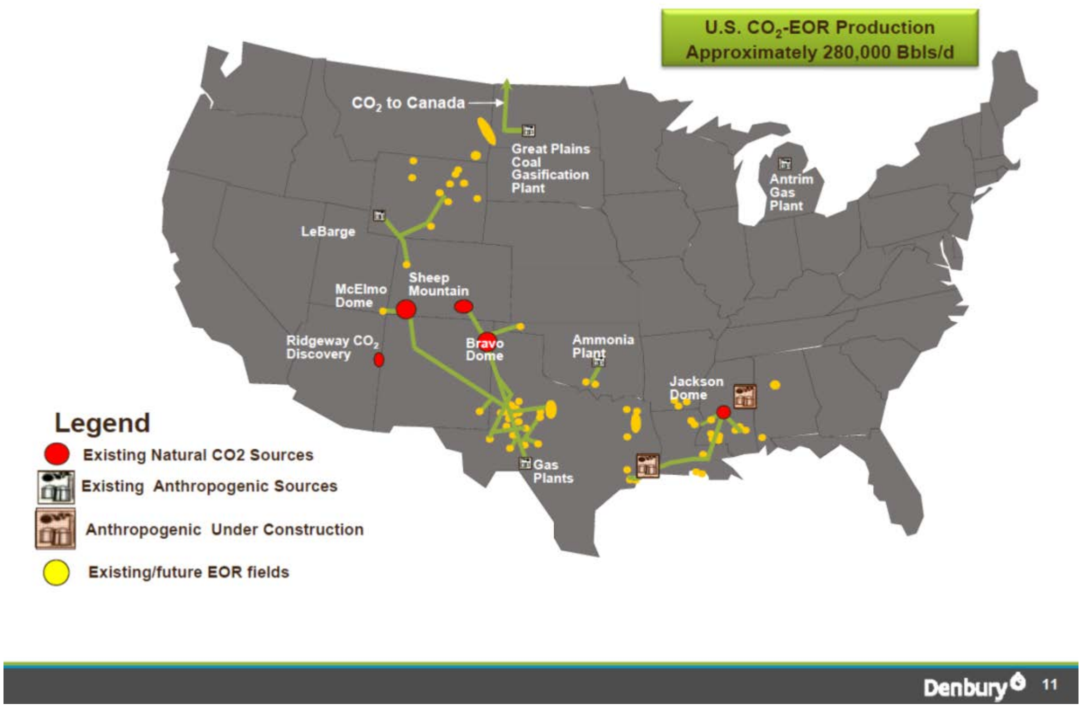
	ICF	ICF	ICF	ICF	ICF		
	CO2 EOR	Depleted Oil	Coal Beds	Saline	Lower-48		Lower-48
	Mid	Mid	Mid	Mid	Mid		Mid
	Volume	Volume	Volume	Volume	Volume		NATCARB
State or Area	Gtonne	Gtonne	Gtonne	Gtonne	Gtonne		Gtonne
ALABAMA	0.07	0.28	3.13	86.70	90.2		90.2
ARIZONA	0.00	0.01	0.00	0.85	0.9		0.9
ARKANSAS	0.08	0.18	2.58	31.87	34.7		34.7
ATLANTIC OFFSHORE	0.00	0.00	0.00	317.00	317.0		317.0
CA. ONSHORE	1.24	2.20	0.00	221.78	225.2		225.2
COLORADO	0.20	1.41	0.68	227.60	229.9		229.9
DELAWARE	0.00	0.00	0.00	0.05	0.1		0.1
FLORIDA	0.13	0.00	2.03	116.33	118.5		118.5
GEORGIA	0.00	0.00	0.05	11.85	11.9		11.9
IDAHO	0.00	0.00	0.00	0.39	0.4		0.4
ILLINOIS	0.10	0.00	2.16	61.91	64.2		64.2
INDIANA	0.02	0.00	0.14	49.91	50.1		50.1
IOWA	0.00	0.00	0.01	0.08	0.1		0.1
KANSAS	0.41	1.18	0.01	8.80	10.4		10.4
KENTUCKY	0.01	0.04	0.19	5.40	5.6		5.6
LA. OFFSHORE	1.46	9.61	0.00	2,133.07	2,144.1		2,144.1
LA ONSHORE	1.36	9.25	13.61	1,101.56	1,125.8		1,125.8
MARYLAND	0.00	0.00	0.00	2.96	3.0		3.0
MICHIGAN	0.08	0.69	0.00	36.56	37.3		37.3
MINNESOTA	0.00	0.00	0.00	0.00	0.0		0.0
MISSISSIPPI	0.13	0.43	8.96	335.20	344.7		344.7
MISSOURI	0.00	0.00	0.01	0.17	0.2		0.2
MONTANA	0.25	2.35	0.32	887.22	890.1		890.1
N. DAKOTA	0.32	4.09	0.60	111.65	116.7		116.7
NEW MEXICO	0.90	6.45	0.19	236.89	244.4		244.4
NEBRASKA	0.02	0.01	0.00	49.85	49.9		49.9
NEVADA	0.00	0.00	0.00	0.00	0.0		0.0
NEW ENGLAND STS	0.00	0.00	0.00	0.00	0.0		0.0
NEW JERSEY	0.00	0.00	0.00	0.00	0.0		0.0
NEW YORK	0.00	0.92	0.00	4.26	5.2		5.2
N. CAROLINA	0.00	0.00	0.00	9.75	9.7		9.7
OHIO	0.00	10.06	0.13	9.94	20.1		20.1
OKLAHOMA	1.41	6.71	0.01	0.00	8.1		8.1
OREGON	0.00	0.00	0.00	52.24	52.2		52.2
PACIFIC OFFSHORE	0.00	0.20	2.30	108.00	110.5		110.5
PENNSYLVANIA	0.00	2.97	0.28	17.26	20.5		20.5
S. DAKOTA	0.00	0.19	0.00	86.69	86.9		86.9
S. CAROLINA	0.00	0.00	0.00	4.93	4.9		4.9
TENNESSEE	0.00	0.00	0.00	3.57	3.6		3.6
TEXAS ONSHORE	7.55	38.65	22.82	2,458.83	2,527.8		2,527.8
TX. OFFSHORE	0.00	5.53	0.00	1,064.93	1,070.5		1,070.5
UTAH	0.28	0.88	0.08	154.84	156.1		156.1
VIRGINIA	0.00	0.06	0.49	0.24	0.8		0.8
WASHINGTON	0.00	0.00	0.00	220.75	220.8		220.8
WEST VIRGINIA	0.00	1.83	0.41	11.21	13.4		13.4
WISCONSIN	0.00	0.00	0.00	0.00	0.0		0.0
WYOMING	0.42	1.88	12.00	644.82	659.1		659.1
Lower 48 Total	16.45	108.05	73.13	10,887.8	11,087.0		11,085.4
Offshore L-48	1.46	15.34	2.30	3,623.0	3,643.0		3,642.1

Source: 2010 NATCARB atlas with ICF EOR

Existing U.S. CO_2 Pipelines

The U.S. has an extensive network of CO_2 pipelines that are used to transport CO_2 for EOR projects, primarily in West Texas, but expanding into the Rockies and Gulf Coast. Currently, the U.S. produces more than 280,000 barrels per day of CO_2 EOR oil production.[14] Over 4,000 miles of pipeline transports more than 65 million tonnes of CO_2 per year from natural and anthropogenic sources. These pipelines operate in the liquid and supercritical CO_2 phases at ambient temperatures and high pressure. Most of the CO_2 is sourced from three naturally occurring deposits in Colorado and New Mexico and transported to West Texas. There is some CO_2 produced from anthropogenic sources, including the Great Plains Coal Gasification Plant in North Dakota and the LaBarge gas plant in western Wyoming. Exhibit 27 is a map showing the major components of the system. Exhibit 28 through Exhibit 30 show details for the major regions.

Exhibit 27: Map of Existing CO_2 Pipelines

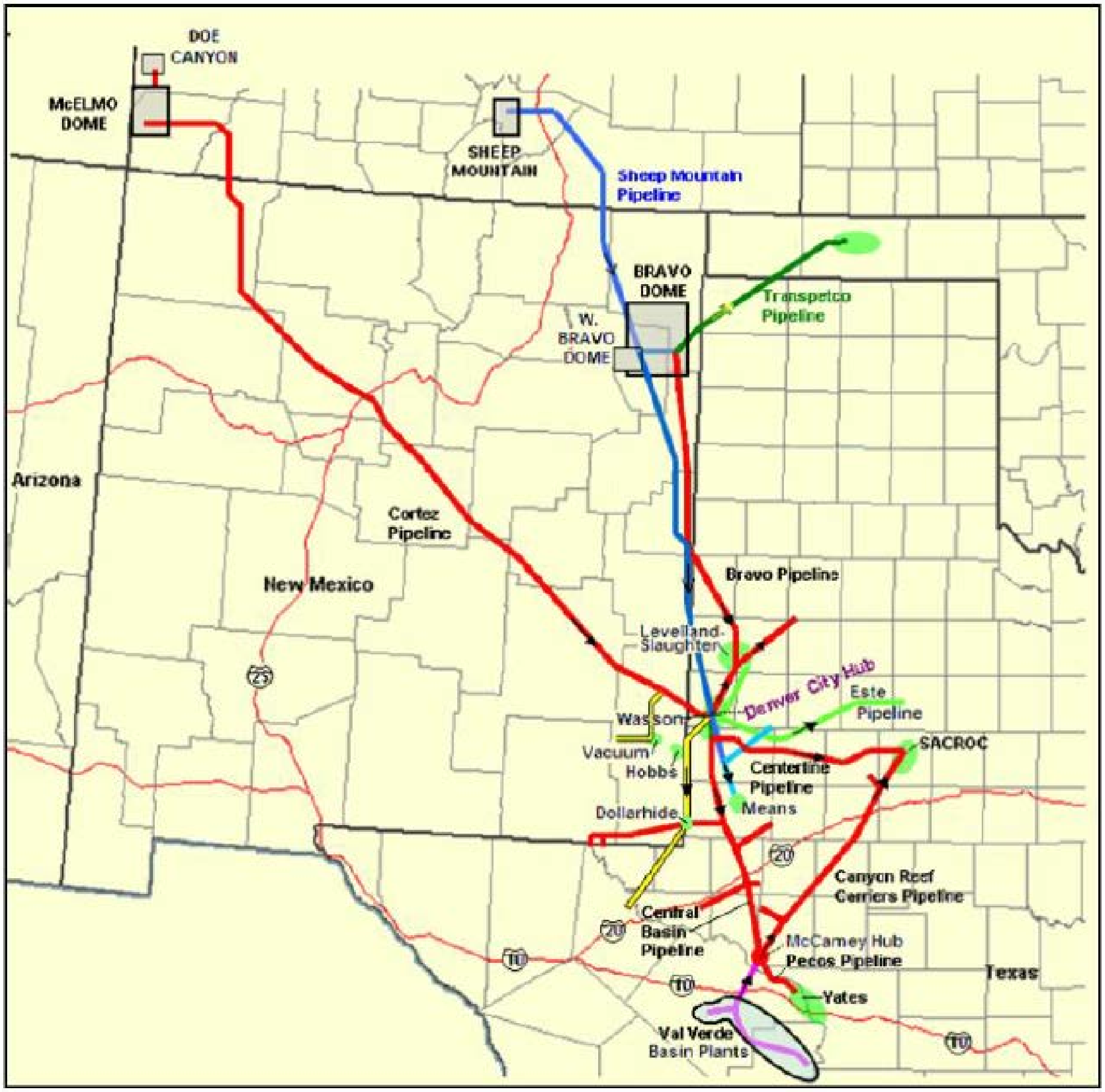


Source: Denbury investor slides, April 2012[15]

[14] DOE/NETL 2011, "Improving Domestic Energy Security and Lowering CO_2 Emissions with Next Generation CO_2-EOR.

[15] Denbury Resources, 2012, "CO_2 Transportation," Investor Slides, April, 2012, 25p.

Exhibit 28: Map of West Texas CO_2 Pipelines



Source: Advanced Resources International, November 2010 report to DOE[16]

Exhibit 31 summarizes currently available information on current U.S. CO_2 pipelines. For each pipeline, information includes length, diameter, and capacity in million cubic feet per day and million tons per year. Exhibit 32 summarizes this information by state or province. This information was originally compiled by Melzer Consulting.[17]

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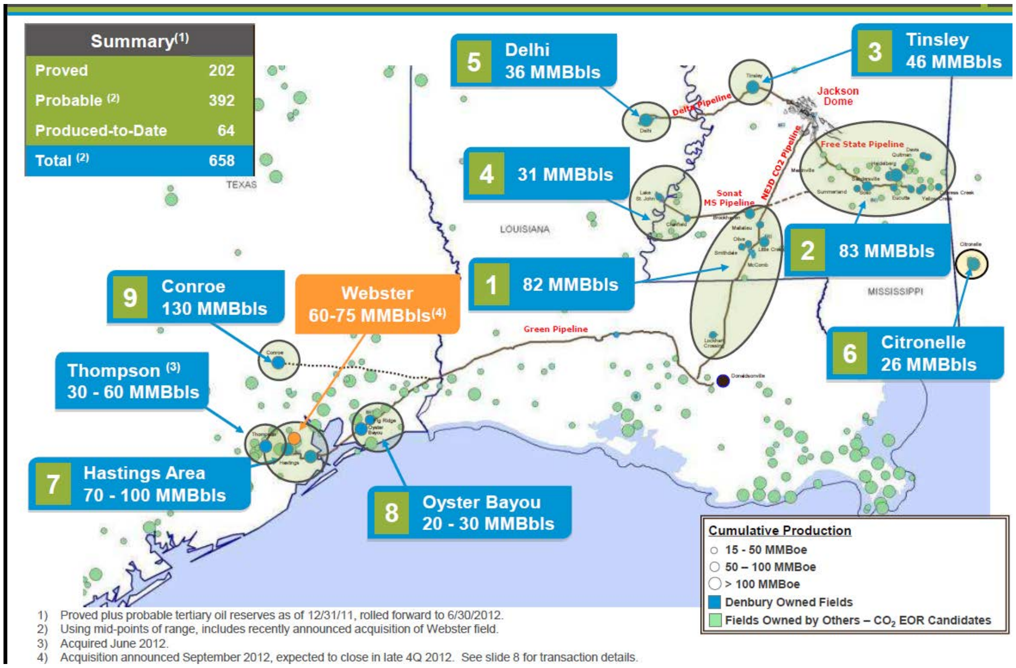
[16] Advanced Resources International, 2010, "Optimization of CO_2 Storage in CO_2 Enhanced Oil Recovery Projects," prepared for DOE, Nov. 30, 2010.

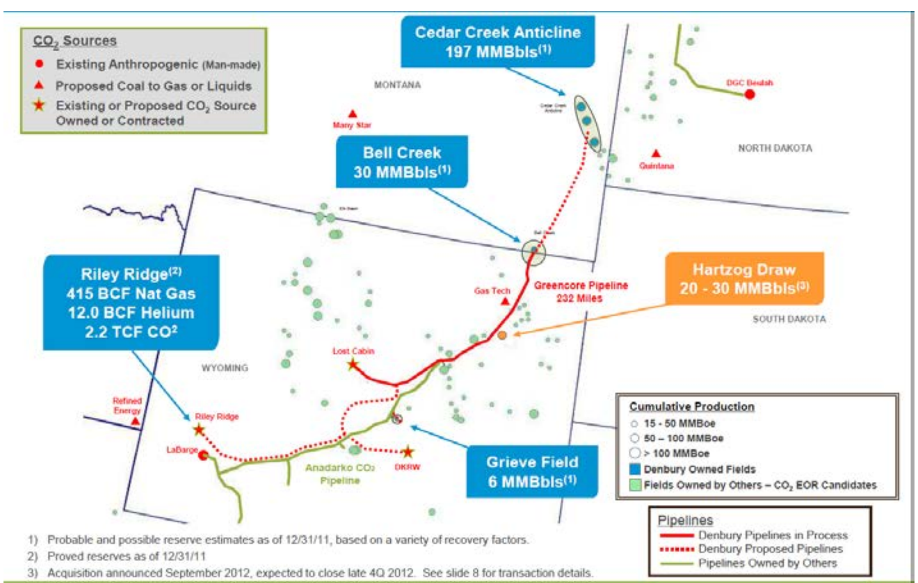
[17] Melzer Consulting, Midland, TX http://www.melzerconsulting.com/

Exhibit 29: Map of SE Texas, LA, and MS CO_2 Pipelines



Source: Denbury Resources, September 2012[18]

Exhibit 30: Map of Rockies CO_2 Pipelines



Source: Denbury Resources, September, 2012[19]

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[18] Denbury Resources, 2012
[19] Ibid

Exhibit 31: Existing North American CO_2 Pipelines

ICF International October 2012							
Based on 2010 public domain data							
PIPELINE	OWNER/OPERATOR	LENGTH (MI)	LENGTH (KM)	DIAMETER (IN)	ESTIMATED MAX FLOW CAPACITY (MMcfpd)	ESTIMATED MAX FLOW CAPACITY (MTPA)	LOCATION (STATE)
Adair	Apache	15	24	4	47	1	TX
Anton Irish	Oxy	40	64	8	77	1.6	TX
Beaver Creek	Devon	53	85				WY
Borger, TX to Camrick, OK	Chaparral Energy	86	138	4	47	1	TX, OK
Bravo	Oxy Permian	218	351	20	331	7	NM, TX
Centerline	Kinder Morgan	113	182	16	204	4.3	TX
Central Basin	Kinder Morgan	143	230	16	204	4.3	TX
Chaparral	Chaparral Energy	23	37	6	60	1.3	OK
Choctaw (NEJD)	Denbury Onshore, LLC	183	294	20	331	7	MS, LA
Comanche Creek (currently inactive)	PetroSource	120	193	6	60	1.3	TX
Cordona Lake	XTO	7	11	6	60	1.3	TX
Cortez	Kinder Morgan	502	808	30	1,117	23.6	TX
Delta	Denbury Onshore, LLC	108	174	24	538	11.4	MS, LA
Dollarhide	Chevron	23	37	8	77	1.6	TX
El Mar	Kinder Morgan	35	56	6	60	1.3	TX
Enid-Purdy (Central Oklahoma)	Merit	117	188	8	77	1.6	OK
Este I to Welch, TX	ExxonMobil	40	64	14	160	3.4	TX
Este II to Salt Creek Field	ExxonMobil	45	72	12	125	2.6	TX
Ford	Kinder Morgan	12	19	4	47	1	TX
Free State	Denbury Onshore, LLC	86	138	20	331	7	MS
Green Line I	Denbury Green Pipeline LLC	274	441	24	850	18	LA
Joffre Viking	Penn West Petroleum, Ltd	8	13	6	60	1.3	Alberta
Llaro	Trinity CO_2	53	85	12-8	77	1.6	NM
Lost Soldier/Werrz	Merit	29	47				WY
Mabee Lateral	Chevron	18	29	10	98	2.1	TX
McElmo Creek	Kinder Morgan	40	64	8	77	1.6	CO, UT
Means	ExxonMobil	35	56	12	125	2.6	TX
Monell	Anadarko			8	77	1.6	WY
North Ward Estes	Whiting	26	42	12	125	2.6	TX
North Cowden	Oxy Permian	8	13	8	77	1.6	TX
Pecos County	Kinder Morgan	26	42	8	77	1.6	TX
Powder River Basin CO_2 PL	Anadarko	125	201	16	204	4.3	WY
Raven Ridge	Chevron	160	257	16	204	4.3	WY, CO
Rosebud	Hess						NM
Sheep Mountain	Oxy Permian	408	656	24	538	11.4	TX
Shute Creek	ExxonMobil	30	48	30	1,117	23.6	WY
Slaughter	Oxy Permian	35	56	12	125	2.6	TX
Sonat (reconditioned natural gas)	Denbury Onshore, LLC	50	80	18	150	3.2	MS
TransPetco	TransPetco	110	177	8	77	1.6	TX, OK
W. Texas	Trinity CO_2	60	97	12-8	77	1.6	TX, NM
Wellman	PetroSource	26	42	6	60	1.3	TX
White Frost	Core Energy, LLC	11	18	6	60	1.3	MI
Wyoming CO_2	ExxonMobil	112	180	20-16	204	4.3	WY
Canyon Reef Carriers	Kinder Morgan	139	224	16	204	4.3	TX
Dakota Gasification (Souris Valley)	Dakota Gasification	204	328	14-13	125	2.6	ND, Sask
Pikes Peak	SandRidge	40	64	8	77	1.6	TX
Val Verde	SandRidge	83	134	10	98	2.1	TX
Total		4,076	6,559		8,916	188.3	
Original Source: Melzer Consulting, Hattenbach, BlueSource (2010).							
Secondary source:							
http://www.globalccsinstitute.com/publications/global-status-ccs-2012/online/48641							

Source: Global CCS Institute[20]

[20] http://www.globalccsinstitute.com/publications/global-status-ccs-2012/online/48641

Exhibit 32: Summary of Existing CO_2 Pipelines

State or Province	Number of Pipelines	Total Miles	Capacity (MMCFD)
Alberta	1	8	60
CO, UT	1	40	77
LA	1	274	850
MI	1	11	60
MS	2	135	481
MS, LA	2	291	869
ND, Sask	1	204	125
NM	2	53	77
NM, TX	1	218	331
OK	2	140	137
TX	23	1,937	3,842
TX, NM	1	60	77
TX, OK	2	196	124
WY	6	349	1,602
WY, CO	1	160	204
	47	4,076	8,916
US Only	46	4,068	8,856

Modeling of Future CO_2 Pipeline Network

In a 2009 study for the Interstate Natural Gas Association of America (INGAA) Foundation, ICF evaluated the potential configuration and scope of a future U.S. CO_2 pipeline network.[21] Prior to the study, little analytical work had been done to evaluate the likely future development of a CO_2 pipeline network and its cost. The study focused on the pipeline infrastructure requirements for CCS in compliance with mandatory greenhouse gas reductions. It concluded that by 2030, between 15,000 and 66,000 miles of pipeline would be required to transport CO_2, depending on how much CO_2 must be sequestered and the extent to which EOR is involved. The study also concluded that while there are no significant technical barriers to building this network, the major challenges will lie in the areas of public policy, regulation, and economics. Because a CCS infrastructure can develop in several ways, it was concluded that the government must address questions about industry structure, government support of early development, regulatory models, and operating rules.

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[21] ICF International, 2009, "Developing a Pipeline Infrastructure for CO_2 Capture and Storage: Issues and Challenges," prepared for the INGAA Foundation, Washington, DC, February, 2009.

The results of this analysis were used to help incorporate future CCS transportation and storage into ICF's IPM® model.

Cost of CO_2 Pipelines

The costs of building pipelines in the U.S. and Canada have been going up significantly in the last several years, due to higher material and labor costs. Costs can vary significantly from location to location based on the terrain, the density of development along the pipeline route and local construction costs. Since there are large economies of scale for pipelines, CO_2 transportation costs would depend on how many power plants and industrial CO_2 sources could share a pipeline over a given distance. The longer the distance from the source to the CO_2 sink, the more chance there is for other sources to share in the transportation costs.

Recent studies have shown that CO_2 pipeline transport costs for a 62 mile pipeline transporting 5 megatonnes per year range from approximately $1 per tonne to $3 per tonne, depending on factors such as terrain, flow rate, population density, labor costs, etc.[22]

ICF INGAA Analysis – Infrastructure Planning Volumes

For the U.S., the infrastructure planning ranges for CCS volumes are:

- 2015: 3 to 50 million tonnes
- 2020: 25 to 150 million tonnes
- 2030: 300 to 1,000 million tonnes

For Canada, the infrastructure planning ranges for CCS volumes are:

- 2015: 10 to 30 million tonnes
- 2020: 30 to 70 million tonnes
- 2030: 90 to 150 million tonnes

The translation of these volumes into transportation infrastructure requirements depends on the location of the CO_2 sources and sinks and the degree to which the CO_2 transportation system is built in an integrated manner in which costs are minimized by combining flows along similar paths into larger pipelines versus built in a piecemeal manner in which most CCS projects construct their own pipeline system.

Including industrial facilities, there are a total of over 1,700 facilities that emit over 100,000 tonnes of CO_2 per year, see Exhibit 33**.** The highest projected annual volume of 1,000 million

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[22] CCS Task Force, 2010, Report of the Interagency Task Force on Carbon Capture and Storage, Washington, D.C., http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.

tonnes per year would be equivalent to the CO_2 amounts that could be captured at about 300 power plants averaging 500 MW in size.

Exhibit 33: Large (> 100,000 tCO_2/yr) CO_2 Sources in US (1,715 in total)

1,053 electric power plants	**259 natural gas processing plants**
126 petroleum refineries	**44 iron and steel foundries**
105 cement kilns	**38 ethylene plants**
30 hydrogen production plants	**19 ammonia plants**
34+ ethanol plants	**7 ethylene oxide plants**

Source: Dooley, 2007 – Battelle PNNL[23]

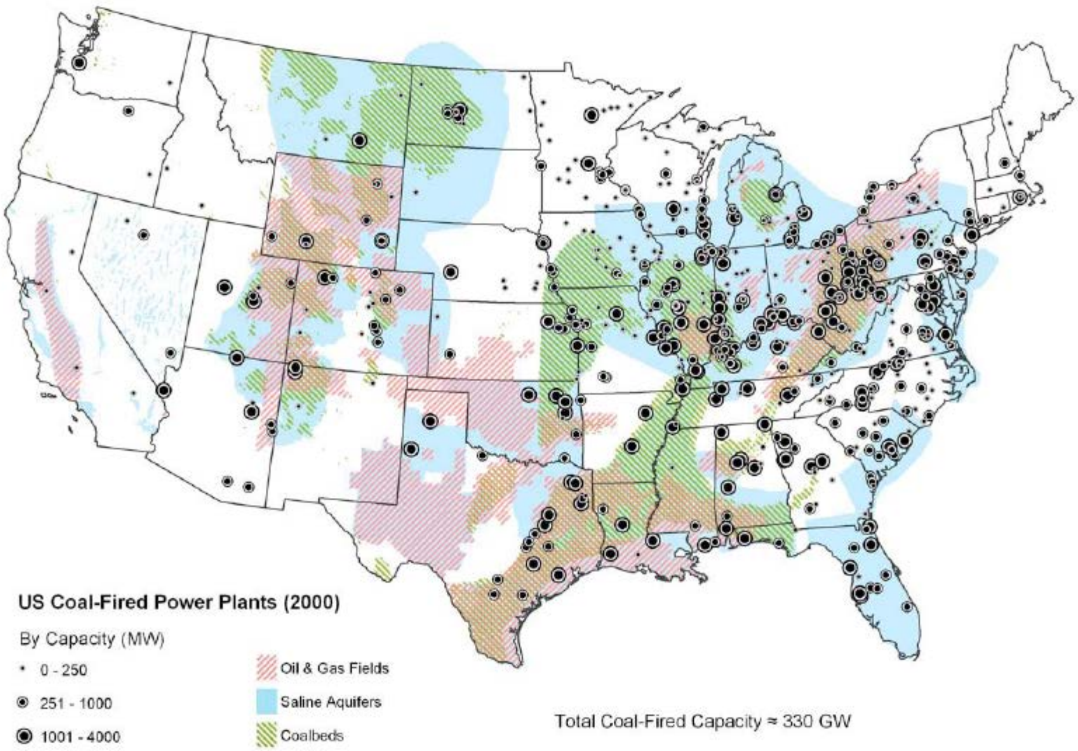
The transportation issue can be illustrated with the help of Exhibit 34 which is a map of U.S. coal power plants and areas with potential geologic storage sites. Large coal plants in the eastern, midwestern and southern parts of the U.S. are generally located an average of 35 to 60 miles from each other and, in theory, could be connected to nearby storage sites by a network of CO_2 pipelines that has a length of about 50 miles per power plant. However, this would require that a large number of coal plants use CCS and that the power plants share pipeline capacity whenever feasible.

For the INGAA study, ICF developed four cases for a CO_2 pipeline network infrastructure, as shown in Exhibit 35. Two of the cases are based on the High requirements for CCS and two are based on the Low Requirements. In turn, each of the CCS cases is evaluated under scenarios with lesser and greater use of CO_2 for EOR: 25 percent in one versus 75 percent in the other.

The High CCS Case results in additions to the existing CO_2 pipeline network (now about 3,600 miles in length) of 20,610 miles by 2030, when EOR use of CO_2 is modest in scope, and additions of 36,050 miles when EOR use of CO_2 is greater. The cost of constructing the new CO_2 pipeline for the High CCS Case ranges from $32.2 billion to $65.6 billion by 2030 using recent average cost factors. Because construction costs vary greatly based on the terrain through which the pipeline is built and the prevailing regional materials and labor costs, actual costs may be much greater than this.

[23] Dr. James Dooley, Pacific Northwest Laboratory, http://www.pnl.gov/

Exhibit 34: Map of US Coal Plants and Storage Sites



Source: MIT, The Future of Coal

The Low CCS Case produces a range of new CO_2 pipeline requirements by 2030 of 5,900 to 7,900 miles depending on the degree to which longer distance transport to EOR sites takes place. The cost of this new pipeline would be between \$8.5 billion and \$12.8 billion.

These results are based on assumptions for distances between captured CO_2 sources and the outputs of ICF's IPM® model. IPM® projects the amounts of CO_2 captured that would likely take place in each electricity generation area and (using the GeoCAT supply curves for various storage options) the amount to geologic storage that would take place in each storage area. The IPM® results were scaled to match this study's assumption for the annual CCS volumes.

The cases with greater use of EOR are based on a more optimistic view of EOR potential that results in an EOR-related storage capacity of 50 gigatonnes versus the 17 gigatonnes for EOR storage in the base GeoCAT data. This larger EOR-related storage volume could come about through the expansion of the oil-in-place that could be targeted by what DOE refers to as "next generation" EOR technologies and the larger amount of CO_2 that could be injected into oil fields if CO_2 were abundant and less expensive than current sources.

Exhibit 35: Cases for U.S. CO_2 Pipeline Requirements

High CCS Case: Lesser Use of CO2 for EOR

	CO2 Pipeline (miles)						
Inch Diameter	12.75	16	24	30	36	42	All Diameters
Miles Needed by 2015	550	270	90	0	0	0	910
Miles Needed by 2020	1,250	830	500	270	100	0	2,950
Miles Needed by 2030	7,190	5,700	4,150	2,500	1,070	0	20,610
	CO2 Pipeline Expenditures ($ millions)						
Expenditures by 2015	526	337	181	0	0	0	1,044
Expenditures by 2020	1,195	1,036	1,008	697	320	0	4,256
Expenditures by 2030	6,875	7,114	8,366	6,450	3,428	0	32,234

Low CCS Case: Lesser Use of CO2 for EOR

	CO2 Pipeline (miles)						
Inch Diameter	12.75	16	24	30	36	42	All Diameters
Miles Needed by 2015	40	0	0	0	0	0	40
Miles Needed by 2020	280	140	50	0	0	0	470
Miles Needed by 2030	2,500	1,660	1,000	540	200	0	5,900
	CO2 Pipeline Expenditures ($ millions)						
Expenditures by 2015	38	0	0	0	0	0	38
Expenditures by 2020	268	175	101	0	0	0	543
Expenditures by 2030	2,391	2,072	2,016	1,393	641	0	8,512

High CCS Case: Greater Use of CO2 for EOR

	CO2 Pipeline (miles)						
Inch Diameter	12.75	16	24	30	36	42	All Diameters
Miles Needed by 2015	550	270	90	0	0	0	910
Miles Needed by 2020	1,310	1,110	780	530	350	0	4,080
Miles Needed by 2030	7,960	9,560	8,010	6,050	4,470	0	36,050
	CO2 Pipeline Expenditures ($ millions)						
Expenditures by 2015	526	337	181	0	0	0	1,044
Expenditures by 2020	1,253	1,385	1,572	1,367	1,121	0	6,699
Expenditures by 2030	7,612	11,931	16,148	15,609	14,322	0	65,622

Low CCS Case: Greater Use of CO2 for EOR

	CO2 Pipeline (miles)						
Inch Diameter	12.75	16	24	30	36	42	All Diameters
Miles Needed by 2015	40	0	0	0	0	0	40
Miles Needed by 2020	280	130	40	-10	-10	0	430
Miles Needed by 2030	2,600	2,160	1,500	1,000	640	0	7,900
	CO2 Pipeline Expenditures ($ millions)						
Expenditures by 2015	38	0	0	0	0	0	38
Expenditures by 2020	268	162	81	-26	-32	0	453
Expenditures by 2030	2,486	2,696	3,024	2,580	2,051	0	12,836

Determining Factors for Future CO_2 Pipeline Development

The key factors determining the location and scale of CO_2 transport corridors include the following:

- Location and nature of CO_2 sources
- Location and economics of CO_2 storage options
- Distance between source and storage sites
- Low population density
- Limited changes in elevation across the pipeline route, limited water body crossings, and reduced crossings of any environmentally sensitive zones
- Availability of any existing right of way (e.g., linking with electric transmission corridors)
- Resolution of regulatory and legal issues related to CO_2 storage in various settings
- Whether or not storage is allowed offshore

Many in industry expect that the early storage projects would have a dedicated pipeline system and would for the most part use nearby storage sites. This expectation stems from the belief that power plants near storage sites would be the most economic and, therefore, would be the first to convert to or be built with CCS. There is also the expectation that in the early phases of the CCS industry, a single entity would control the entire CCS project (capture, transport and storage) to better manage commercial, regulatory and liability risks. Such projects might frequently be expected to be undertaken by a regulated utility that will put the entire project within the jurisdiction of the relevant regulatory commission.

Over time, as more CCS plants are developed there will be a tendency to connect plants that are further away from storage sites. However, the greater density of CCS plants and increased imperative to reduce transportation costs for longer distance transportation would lead to more shared pipelines as CCS grows. Under this view, the later CCS development would tend to have larger diameter pipelines than in the early phase. The pipeline network mileage averaged per CO_2 source, may be similar between the early and later development phases, since that larger source-to-sink distances in the later phase would be offset by sharing of pipeline capacity.

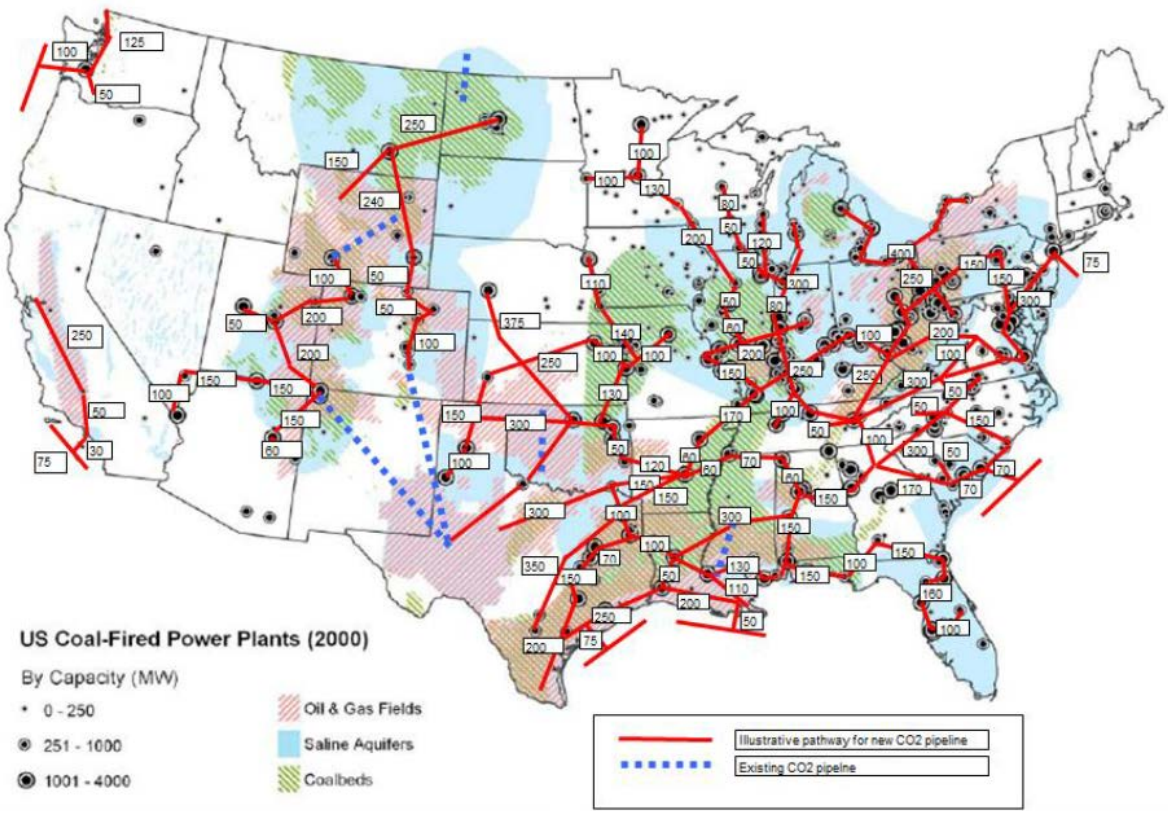
Another important determinant of the evolution of the CO_2 pipeline network will be the degree to which the CO_2 will be used for EOR. The spatial distribution to saline reservoirs is much wider and the estimated capacity is 175 times larger for than for EOR. Therefore, it is statistically more likely that a CO_2 source will have a suitable saline reservoir closer to it.[24] This means that if the storage network serves EOR to a very large degree, it will likely be transporting CO_2 over longer distance than a system that moves CO_2 from sources to saline reservoirs.

Finally, if "NIMBY" concerns become to dominate the public concerns on CO_2 storage, then one potential option is storage in offshore areas—in particular offshore areas where EOR is possible (e.g., offshore Louisana and Texas).

One possible layout of the U.S. CO_2 pipeline system for the INGAA case requiring the most pipeline development (High CCS Case with Greater Use of EOR) is shown in Exhibit 36. The new mainline corridors depicted as red lines in the map sum to 13,500 miles. Adding pipeline mileage for the expected multiple pipelines on many corridors and pipeline required to connect individual sources and sinks to the system yields the total new transmission pipeline requirement of 36,050 miles. The High CCS Case with Lesser Use of EOR would not require this degree of interconnectivity and would not show as much new capacity going into the oil producing areas. This case also shows the development of offshore pipelines in the Gulf of Mexico, Atlantic and Pacific offshore basins.

[24] However, it should be emphasized that not all saline reservoirs will be suitable for long term CO_2 storage due to poor reservoir characteristics (low porosity and permeability), lack of an impermeable cap rock to restrict CO_2 escape, excessive discontinuous features and faulting, a too-thin thickness that will require a large surface area be disturbed or affected and proximity to densely populated areas that will make land difficult to assemble and facilities permits difficult to obtain.

Exhibit 36: Map of Possible CO_2 Pipeline Corridors for a High CCS Case with Greater Use of EOR



Task 2: Environmental Policy Concerns

Existing and proposed environmental regulations play a key role in shaping the role that new and existing coal-fired power plants will play in the generation mix. There are a large number of existing and proposed environmental regulations facing the power generation sector (see Exhibit 37). Many of these regulations affect coal-fired power plants in particular, although due to their scope, many of the rules impact the entire power sector more generally. These regulations have also faced numerous legal challenges, creating an uncertain planning environment for plant owners, operators and regulators.

Exhibit 37: The 5 Major Rulemakings Impacting the Power Sector

	Plants Affected	2013	2014	2015	2016	2017	2018	2019	2020+
SO_2 & NO_x (CAIR)	Existing+New			CAIR Replacement?					
Air Toxics (MATS)	Existing+New				Full Implementation				
Cooling Water Intake	Existing+New								
Coal Ash (CCR and ELG)	Existing+New								
Greenhouse Gas NSPS	New								

2.1 Clean Air Interstate Rule (CAIR) and the Cross State Air Pollution Rule (CSAPR)

The Clean Air Interstate Rule (CAIR) was originally finalized by the U.S. Environmental Protection Agency (EPA) in March of 2005. CAIR was designed as a tool to help states meet federal regulations for $PM_{2.5}$ and 8-hour ozone standards under National Ambient Air Quality Standards (NAAQS). The purpose of CAIR was to address the interstate transport of these pollutants to facilitate counties in non-attainment status in reaching attainment status. SO_2 and NO_X emissions (NO_X from transportation and power plants and SO_2 almost exclusively from power plants) are precursors to $PM_{2.5}$ formation, therefore the SO_2 and annual NO_X standards in CAIR were designed to help with attainment of the current $PM_{2.5}$ standard. The ozone season NO_X standard was designed to help with attainment of the current 8-hour ozone standard. The rule covered 27 states and the District of Columbia, grouping them into some or all of three unique programs.

In July 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAIR. The court ruled that the cap and trade structure of CAIR did not meet the Clean Air Act's requirement that EPA establish a concrete linkage between upwind pollution and nonattainment in downwind locations. In response, the EPA filed a petition for the court to rehear the case, or as an alternative, to remand its decision without vacatur so that the EPA might correct the flaws highlighted by the court. The court opted to remand the decision in order to avoid any negative environmental impacts associated with vacating the rule entirely, and the rule continues to remains in effect until EPA's replacement is made final.

In July 2010, EPA released its proposed replacement for CAIR, the Clean Air Transport Rule (CATR). This proposed replacement was finalized as the Cross-State Air Pollution Rule (CSAPR) in July 2011 after making several program changes based upon industry feedback. EPA intended for CSAPR to replace CAIR beginning on January 1st, 2012.

Much like CAIR, CSAPR consisted of annual requirements for SO_2 and NO_x emissions and ozone-season requirements for NO_x emissions (although for different groupings of states). Under the rule, covered states were given budgets under each program.[25] Affected entities were then provided with allowances based on extensive modeling concerning their own contributions to the states emissions. Entities were then allowed to purchase additional allowances from others within each of the programs, regardless of the state of origin. However, beginning in 2014, (after being moved up to 2012 and then delayed again to 2014), entities would be charged with penalty allowances should their emissions cause their state to exceed its annual allowance budget plus an assurance level of 18%. This provision limited interstate trading.

On December 30th 2011, the court stayed CSAPR pending its review of the many challenges to the finalized rule. The court then heard arguments from the challengers and the EPA in mid-April 2012. On August 21, 2012, the court vacated the rule in its entirety. As part of the ruling, the court required EPA to continue to enforce CAIR. The three-judge panel found many of the same faults with CSAPR as it had with CAIR, deciding that as designed, the upwind states might have to reduce emissions by more than any significant contribution they might make to the nonattainment areas in the downwind states. The court also ruled that the EPA superseded states' rights by imposing a federal implementation plan before states could craft and implement their own emissions reduction plans.[26]

On October 5, 2012, EPA challenged the court's decision to vacate CSAPR in its entirety by requesting an *en banc* hearing that would involve the full bench of judges at the court instead of the three-judge panel that originally made the ruling.[27] During the EPA's challenge to the court's decision, the CAIR program will remain in place to govern SO_2 and NO_x emissions. It is ICF's current view that is unlikely that the court's decision will be changed in any significant way.

If the *en banc* hearings do not result in a reinstatement of CSAPR, EPA could either move to develop a new replacement for CAIR, or – and perhaps more likely - move ahead to establish new rules based on the latest NAAQS standards. EPA's analysis for CSAPR was based on the 1997 annual $PM_{2.5}$ NAAQS, the 1997 ozone NAAQS, and the 2006 24-hour $PM_{2.5}$ NAAQS. If

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[26] Crawford, Jonathan. "Update: DC Circuit strikes down cross-state rule, finds agency exceeded authority" via SNL Financial. August 21, 2012.
[27] Lowrey, Dan. "EPA seeks full appeals court review of CSAPR vacatur ruling" via SNL Financial. October 5, 2012.

EPA re-writes the rule to base the states' budget on more recent revised NAAQS, it will add time to the process and likely result in greater SO_2 and NO_X reduction obligations. In either case, the ruling will likely delay SO_2 and NO_X requirements to such an extent that other regulations (e.g., MATS, described later will likely be in effect by the time of the updated CAIR/CSAPR implementation. In most situations, complying with MATS will put sources in a good position to be in compliance with any new SO_2 requirements, leaving only NO_X attainment to be the driver for incremental change in control or retirement decisions going forward. In the meantime, EPA is seeking to finalize revisions to the primary and secondary annual $PM_{2.5}$ standards by December 14, 2012, and the ozone standards in late 2014.

With the court's vacatur of CSAPR, downwind states could challenge the upwind states in courts through Section 126 of the Clean Air Act, which allows a state can petition EPA to impose emission reduction requirements on a source in a neighboring state if its emissions are contributing to the downwind state's non-attainment with NAAQS. Additionally, the court's vacatur of CSAPR and remand of CAIR may mean that some units may be subject to EPA's Regional Haze Rule (RHR), which requires reduction of visibility imparing pollutants, including SO_2 and NO_X in certain "Class I" areas. This will likely result in some units in the EI being required to install controls under Best Available Retrofit Technology (BART) requirements. Both Section 126 petitions and the RHR are state- and site-specific, but may result in some units in the EI to install SO_2 and/or NO_X controls.

In the meantime, the court's requirement that CAIR remain in effect means that many sources in the EI will need to acquire and submit allowances to cover their SO_2 and NO_X emissions each year. CAIR allowance prices remain low due to a very large bank of existing Title IV SO_2 allowances and modest requirements for emissions reductions, and unless the caps are tightened either through lower NAAQS or a new program, increased market activity is unlikely.

2.2 Mercury and Air Toxics Standards (MATS)

EPA finalized the Mercury and Air Toxics Standard (MATS) rule on December 21st, 2011, specifying requirements to control emissions of mercury, acid gases and toxic metals from power plants. These hazardous air pollutants (HAPs) are regulated under Section 112 of the Clean Air Act, which does not permit use of a cap and trade system to meet reduction requirements. Instead, the MATS Rule sets emission rate standards for affected sources that must be complied at the unit- or facility-level. These standards are determined by EPA based on a maximum achievable control technology (MACT) limitation for each pollutant. Emission rates at top 12 percent performing existing units will be used to set the limitation. MATS sets compliance requirements for three pollutants as surrogates for larger classes of pollutants: mercury (Hg), filterable PM (PM, for the group of non-Hg heavy metals), and hydrogen chloride (HCl, for acid gases). Affected sources must also implement work practice requirements to address two other categories of gases (CO and dioxin/furan). The EPA claims that the final rule will eliminate 90% of mercury emissions from power plants, 88% of acid gas emissions, and reduce SO_2 emissions 41% more than what they expected to achieve through CSAPR.[28]

With the release of the final rule at the end of 2011, the final compliance date for the affected sources under MATS under the Clean Air Act will be April 16th, 2015 (three years from publication of the final rule, April 16th, 2012). However, as the permitting authorities under the rule, states have the option to grant up to one additional year for affected entities to complete control installations. Assuming such extensions are widely available (an assumption being given credence by EPA's expanding definition of completing control installations to include installing replacement capacity off-site), many plants may have until April 2016 to achievea fourth year for compliance.

During the final weeks leading up to the publication of the final rule, several groups filed lawsuits questioning the legality of MATS, including the Utility Air Regulatory Group (UARG), Colorado's Tri-State Generation and Transmission Association, and the American Public Power Association (APPA). The challenges focused on the need for more time and flexibility to comply with the standards, especially the new source emission standards of the MATS rule for fossil-fuel-fired electric utility steam generating units (EGUs). The new source emission standards portion concern PM, SO_2, and NOx emissions from new coal- and oil-fired power plants. The court has yet to hear arguments related to those challenges.

The EPA projects the cost of MATS to be an annualized $9.6 billion (2007$).[29] Under MATS, many coal- and oil-fired power plants will incur capital and increased VO&M expenditures to comply with the program. Given that 84% of the total U.S. coal capacity is in the EI, the EI region will bear a portion of this cost. To date, approximately 40 GW of coal-fired capacity retirements have been announced mostly due to the MATS rule. In actuality, and given the persistence of low gas prices, that number could easily increase to over 60 GW of retirements, the vast majority of which is in the EI (see Exhibit 38).

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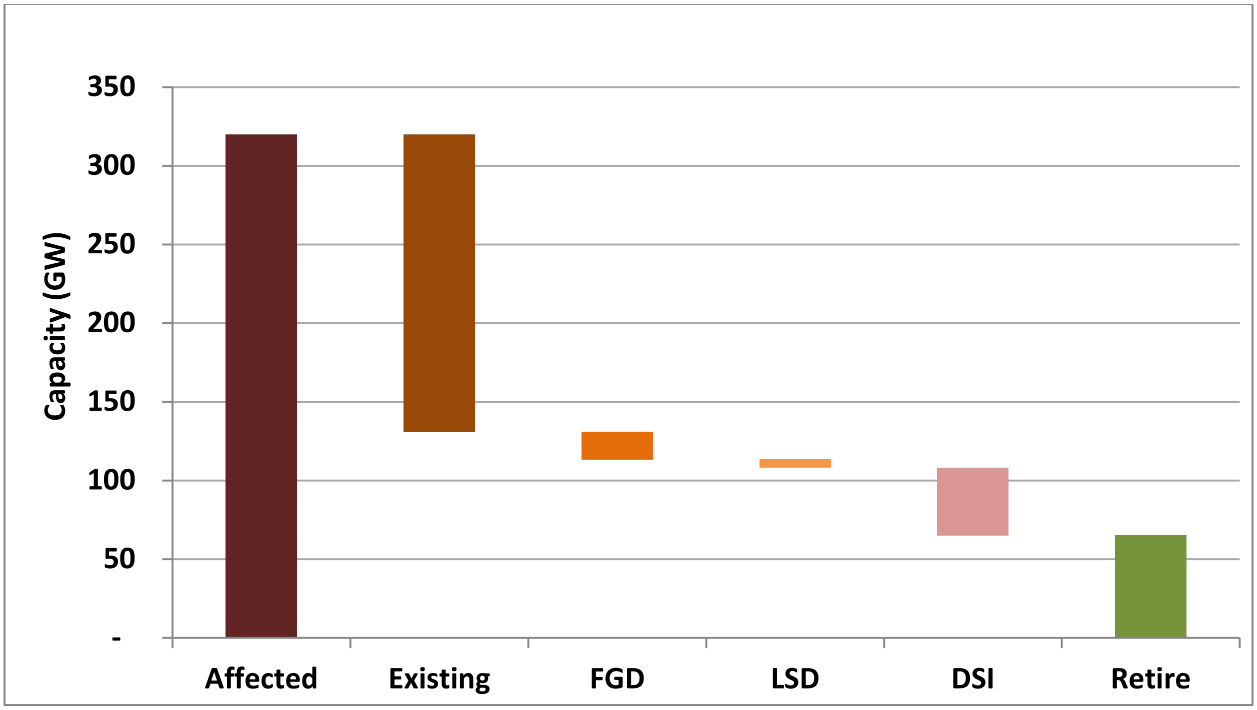
[28] EPA MATS Fact Sheet, "Benefits and Costs of Cleaning Up Toxic Air Pollution from Power Plants", December 2011. http://www.epa.gov/airquality/powerplanttoxics/pdfs/20111221MATSimpactsfs.pdf

[29] EPA, Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, December 2011. (http://www.epa.gov/mats/actions.html)

Exhibit 38: Cumulative Control Installations and Coal Unit Retirements by 2016



2.3 Cooling Water Intake Structures

Section 316(b) of the Clean Water Act (CWA) seeks to address impingement (where aquatic life is trapped against thermal power plants' intake screens and injured or killed as a result) and entrainment (where organisms are drawn into the once-through cooling system and killed by pressure and high temperatures). This particular section of CWA concerns only withdrawals – not discharges – for cooling purposes by point sources. It grants EPA the authority to regulate "location, design, construction and capacity of cooling water intake structures" to ensure that these structures reflect "the best technology available ("BTA") for minimizing adverse environmental impact."

In March 2011, EPA released a revised Phase II rule covering large, existing generating plants under section 316(b), including coal-fired, nuclear and other steam units. The rule requires compliance at facilities with once-through intake systems. The intent of the rule is to reduce both the impingement and entrainment of aquatic life. EPA designed the impingement requirements to reduce the number of organisms pinned against the intake structure by 80-95% compared to uncontrolled levels. EPA intends for the entrainment requirements to lower the animal-trapping incidents in the cooling system by 60-90%. Under the proposed rule, compliance requirements will be determined by each state following site-specific assessments related to the cost and performance of potential entrainment reduction options. Recently, EPA reached a modified settlement agreement in the U.S. District Court of New York to receive an additional year to finalize the rule, allowing time for additional analysis and review of public comments on two Notices of Data Availability. With the extension, EPA must issue the final standards by late June 2013.

The rule will phase-in compliance with the entrainment standards over time as units renew their National Pollutant Discharge Elimination System (NPDES) permits. Affected sources must achieve compliance with the impingement requirements no later than eight years after the final rule is issued. The states will ultimately determine the compliance requirements for affected facilities, subject to review by EPA. The costs for compliance will vary from relatively low cost measures such as modified traveling screens and fish returns to more costly measures such as cooling towers. The EPA estimates that once effective, this particular rule will affect approximately 550 facilities nationally and have an annual cost of about $400 million to $5.1 billion depending on which option is included in the finalized rule.[30]

Of the 269 GW of coal capacity in the EI, approximately 137 GW have once through cooling systems and are already in compliance with the standards.

2.4 Coal Combustion Residuals (Ash) and Effluent Limitations Guidelines (ELG)

Coal combustion residuals (CCRs), also known as coal ash, refer to the materials that remain after burning coal to generate electricity, which include fly ash, bottom ash, boiler slag, and flue gas desulfurized gypsum. In 2008, power generators produced more than 136 million tons of CCRs, which are currently exempt from the Resource Conservation and Recovery Act (RCRA). Following the ash pond failure at TVA's Kingston plant, EPA released a proposed rule in June 2010 for the handling of CCRs to address the risk from waste produced and disposed of by electric utilities and/or independent power producers. EPA has identified a total of 427 coal-fired units nationwide that manage CCRs.[31] Based on RCRA, EPA created a framework for the management of hazardous and nonhazardous solid wastes, including ash from coal-fired boilers. In that proposal, it offered two potential regulatory approaches to reduce wet handling of ash; one under RCRA Subtitle C and another under Subtitle D. The two are similar with the major difference being that Subtitle C proposes that the waste be handled and disposed of as a hazardous substance, while Subtitle D does not. Treatment of the CCRs as hazardous waste could potentially add significant costs to the disposal of ash. Regulation under Subtitle C would also put the program under federal oversight, whereas Subtitle D enforcement would be managed by the states.

The CCR Rule will regulate wet handling of ash, including disposal of ash in ponds, impacting roughly 56% of the coal-fired capacity in the EI. Compliance measures will vary depending on the facility and the Subtitle (C or D) under which the CCRs are regulated. Potential modifiations to existing facilities may include conversion to dry ash handling for fly and bottom ash, construction of landfill replacement capacity, and the installation of waste water treatment facilties for units with existing wet scrubbers.

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[30] EPA, Economic and Benefits Analysis for Proposed Section 316(b) Existing Facilities Rule, March 28 2011, http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/econandbenefits.pdf

[31] Fact Sheet: EPA Region IX Coal Combustion Residuals (CCR) Surface Impoundments. http://www.epa.gov/region9/waste/enforcement/pdf/2009_R9-CoalAsh-factsheet.pdf

EPA stated on October 11, 2012, that it will need at least a year to review and address comments on revisions to the CCR Rule. If EPA is granted an additional year, the timing for the final rule would be late 2013. If the rule is finalized in late 2013, the deadline for compliance if regulated under Subtitle D would be in 2018, while under Subtitle C it would likely be in 2020. For the proposed rule, EPA estimated the annual average costs for the next 50 years to be $1,474 million a year (under subtitle C) and $587 million a year (under subtitle D). The total costs for option C and option D are estimated to be $20.3 billion and $8.6 billion respectively with a 7% discount rate over 50 years.[32]

Additionally, On April 19, 2013, EPA signed a notice of proposed rulemaking to revise the technology-based effluent limitations guidelines (ELG) and standards for this industry that would strengthen the existing controls on discharges from steam electric power plants. The proposal sets the first federal limites on the levels of toxic metals in wastewater that cen be discharged from power plants.[33] EPA estimated an annual cost between $185 million and $954 million as a result of this proposed rulemaking, and the benefits are as follows: The proposed rule reduces yearly pollutant discharges by 470 million to 2,620 million pounds, reduces yearly water usage by 50 billion to 103 billion gallons, decreases neurological damage and cancer risk in humans from exposure to toxic metals, decreases sediment contamination, and improves aquatic life and wildlife health.[34] As little as 0.32 GW of the nation's electric generating fleet expected to retire, and the majority of coal-fired power plants is expected to incur no additional cost under any of the proposed standards.[35] EPA intends to align ELG with CCR rule proposed in 2010 under RCRA, seeking comment from industry and other stakeholders to ensure both ELG and CCR final rules are aligned, so pollution is reduced efficiently while minimizing regulatory burdens.[36]

Under Clean Water Act, effluent limitations are to be revised every five years, however, effluent limitations were last revised in 1982. The Court mandated requirement calls for action by May 22, 2014, and the requirement is from consent decree between EPA and Defenders of Wildlife, EarthJustics, Environmental Integrity Project, and Sierra Club. On June 7, 2013, EPA released several supporting technical papers for the ELG rule, including a document showing that the Office of Management and Budget has significantly weakened the draft version of the proposed rule.[37] Depending on the eventual alternative selected as the final rule, the proposed rule affects wastewaters associated with the following: fly ask, bottom ash, flue gas desulfurization, flue gas

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[32] EPA CCR Rule RIA http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ccr-rule/ccrfaq.htm#20
[33] EPA, Proposed Effluent Limitation Guidelines & Standards for the Steam Electric Power Generating Industry. http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/proposed_factsheet.pdf
[34] *Ibid*.
[35] EPA New Releases By Date, EPA Proposes to Reduce Toxic Pollutants Discharged into Waterways by Power Plants. http://yosemite.epa.gov/opa/admpress.nsf/0/8F5EF6C6955F6D2085257B52006DD32F
[36] SNL, EPA poised to propose revised toxic wastewater discharge rules for power plants. http://www.snl.com/interactivex/article.aspx?id=17505037&KPLT=6
[37] SNL, Earthjustice: Document shows OMB 'significantly weakened' power plant discharge rule. http://www.snl.com/Interactivex/article.aspx?ID=17930877

mercury control, combustion residual leachate, nonchemical metal cleaning waste, and gasification of fuels such as coal and petroleum coke.

2.5 Greenhouse Gases (GHG) New Source Performance Standards (NSPS)

On March 27, 2012, EPA proposed the GHG New Source Performance Standards for Electric Generating Units (EGU GHG NSPS). EPA's proposed NSPS for GHG requires all new fossil-fuel-fired power plants to meet an emissions rate standard of 1,000 lb. CO_2/MWh, roughly similar to the emission rate of widely used natural gas combined cycle technologies, regardless of fuel type. Plants can either meet the proposed standards through fuel switching, or by incorporating carbon capture sequestration (CCS) technology. EPA's proposal does not apply to plants currently operating or newly permitted plants that begin construction within a year of the release of the proposed rule. The proposed rule's definition of fossil-fuel-fired EGUs includes fossil-fuel-fired boilers. It excludes integrated gasification combined cycle (IGCC) units, and stationary natural gas combined cycle turbine units that generate electricity for sale and are larger than 25 MW in capacity.

There are several aspects of the proposed NSPS rule that have caused controversy, especially among owners and operators of coal-fired plants. First, this is a single-standard rule regardless of fuel type. By establishing a common NSPS for EGUs under this rule, EPA is setting a stricter standard for coal compared to new natural gas combined cycle units. Second, as the rule will apply to units that begin construction after April 27, 2013, "transitional sources" have voiced concerns that the proposed one-year timeline is insufficient for the proposed rule to become effective, especially while the new source performance standards under MATS are being reconsidered by EPA. Transitional sources are those sources that are far enough along in development that EPA allowed them one year to begin construction in order to avoid being subject to the standard. Finally, the proposed 1,000 lb. CO_2/MWh standard is fairly stringent and challenging for compliance. Such a standard requires a coal-based unit to use CCS technology, which is not yet mature and is quite expensive. The EPA has so far refrained from committing to a timeline regarding GHG standards for existing sources.

On June 25, 2013, President Obama announced in the President's Climate Action Plan that he is issuing a Presidential Memorandum directing the EPA to effectively reissue carbon pollution standards for new generating sources, and for the first time, to issue carbon standards for existing sources. The form of those regulations, including the stringency and flexibility allowed, will be developed by the EPA, with a proposed rule due by June 2014, and a final standard due by June 2015.[38]

In summary, both new and existing coal-fired power plants face an array of regulations that, together with low natural gas prices, will fundamentally alter the role of coal-fired generation going forward. With 40 GW of coal-fired capacity retirements already announced, and more

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[38] Executive Office of the President, The President's Climate Action Plan. http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf

expected by the 2015 compliance deadline, existing coal-fired capacity are likely to be reduced nationally from approximately 315GW to 250GW. Beyond that, another 50 GW of coal-fired capacity is “on the margin” and will have some tough decisions regarding whether to retrofit to meet the new rules in light of low gas and power prices, or to retire. New coal plants face the double challenge of, while being generally compliant with MATS and other potential SO_2 and NO_X requirements, low natural gas prices and new source GHG NSPS requirements. If currently NSPS regulations remain in place, the only way new coal plants could be built is with CCS, which in and of itself, presents both technological and cost hurdles.

Task 3: Assessing Coal Technologies

3.1 Introduction

In this task, ICF evaluated the cost and performance data of new coal fired power plants using a variety of publicly available sources. Cost and performance data include capital costs, fixed operating & maintenance costs (FOM), variable operating & maintenance costs (VOM), heat rate, and internal power consumption requirements. The analysis is based on projected characteristics of power plants using different coal technologies, as determined by various published sources. ICF evaluated data from the National Energy Technology Laboratory (NETL), the National Renewable Energy Laboratory (NREL), the U.S. Energy Information Administration (EIA), and the Global CCS Institute (GCCSI).

Together these sources provide the relevant information covering the following coal technologies: subcritical pulverized coal (PC), supercritical pulverized coal (SCPC), and ultrasupercritical pulverized coal (USCPC), circulating fluidized bed combustion (CFB), biomass cofiring with pulverized coal, chemical looping combustion (CLC), integrated gasification combined cycle (IGCC), and coal to synthetic natural gas (coal to SNG). For each of these technologies, the sources provide information on how the addition of carbon storage and storage (CCS) technologies affects the cost and performance. Coal technologies data is also compared with natural gas combined cycle (NGCC) costs to provide context to the building of new power plants in the U.S..

Additionally, the analysis also includes a brief discussion concerning the planning horizon, potential R&D, and learning rates for these technologies. A list of demonstration projects by technology (i.e. IGCC, CCS, subcritical PC, SCPC, USC-PC, and CFB) is also provided.

3.2 Challenges in Estimating Costs

Developing cost estimates for technologies is not simple. Generally, cost estimates are used by the government (policymakers), non-governmental organizations (NGOs), and industry for two main purposes: technology assessment and comparison, and policy assessments. The technology assessments can be used to support decisions on technology selection, capital investments, marketing strategies, R&D priorities, and related activities; whereas policy assessment are aimed at variety of regulatory, legislative, and advocacy activities.[39]

There are many different approaches to understanding and using cost estimates. For example, technology assessment cost studies often seek to compare the expected costs of two or more technology options as part of a feasibility or screening process. In these types of studies, the focus is often on the differences in costs, rather than the absolute value of an expected project cost. In contrast, cost estimates for specific projects aim to provide the owner with as accurate an estimate as possible of all the project costs that must be financed. In this case, the

[39] Private Communication, Howard Herzog, November 2012.

technology has already been selected, and the focus is on the many site-specific elements that affect a project's cost.

Indeed, there are often a tension between the generators and users of publicly available cost information. Different audiences often evaluate information from different perspectives, while generators of the content also seek to provide cost information for a variety of purposes. Therefore, any particular cost estimate must therefore be examined and interpreted with care.[40]

In general, the best cost estimates are from studies performed by engineering firms for the major industrial and governmental organizations, such as the Electric Power Research Institute (EPRI), U.S. Department of Energy (DOE), and the International Energy Agency Greenhouse Gas Programme (IEAGHG). In the cost estimates evaluated by ICF, the information was collected from studies commissioned from the National Energy Technology Laboratory (NETL), National Renewable Energy Laboratory (NREL), U.S. Energy Information Agency (EIA), and the Global CCS Institute.

The cost estimates from the national labs are derived from a cost model that relies on specific assumptions about plant characteristics and performance, financing, and commodity prices. Cost estimates from different sources often have varying assumptions, and it is most important to evaluate these on a common/similar cost basis.

In the following sections, we will describe some of the overarching (global) assumptions for the different studies and then technology-specific assumptions from the different studies in the following section. In general, the nominal cost of power generation technologies increased significantly over the recent decade. The increase of commodity prices has been steep for iron, steel, concrete, copper, nickel, zinc, and aluminum. These commodities, which are essential for coal and nuclear plants, have experienced a rate of increasing prices higher than general inflation. Meanwhile, costs of engineers and construction have witnessed a similar pattern.[41]

3.3 Global Assumptions

Estimates of capital costs are often defined using different metrics. The NETL, for example, uses the terms: bare erected cost (BEC), total plant cost (TPC), total overnight cost (TOC), and total as-spent cost (TASC). The exhibit below illustrates the relationship among these four cost categories and composition of each type of capital cost.[42] ICF used the TOC as the metric for capital cost, as this was more comparable to capital cost estimates from other sources. The capital cost estimates are also dependent on labor costs. NETL, for example, assumes that labor costs are based on a 50-hour work week, and labor rates are on par with that of Midwestern states, more specifically the region of IL, IN, MI, MN, OH, and WI.

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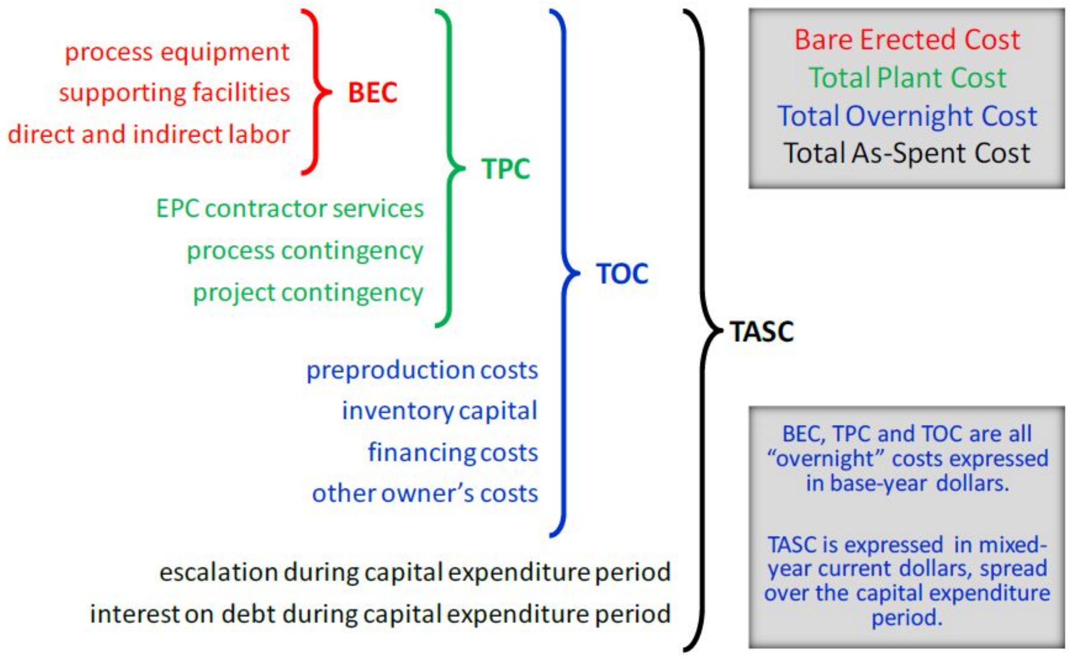
[40] E. Rubin, "Understanding the pitfalls of CCS cost estimates", International Journal of Greenhouse Gas Control 10 (2012) 181–190.
[41] NREL (prepared by Black & Veatch), Cost and Performance Data for Power Generation Technologies, February 2012.
[42] EPRI, on the other hand, uses a slightly different metric. See: Rubin, 2012.

Exhibit 39: Defining capital costs



Source: NETL, Cost and Performance Baseline for Fossil Energy Plants

Fixed operating and maintenance cost (FOM) generally consists of the following categories: operating labor, maintenance labor, administrative and support labor, maintenance materials, property taxes, and insurance. Variable operating and maintenance cost (VOM) often comprises consumables including chemicals, auxiliary fuels, and water, waste disposal cost, CO_2 transport and storage cost when applicable, byproduct sales or credit, and emission tax or credit.[43] In general, VOM varies with generated electricity (kWh), but FOM does not.

NETL

NETL published a revised report entitled *Cost and Performance Baseline for Fossil Energy Plants* in November 2010 using 2007 cost basis, and updated the numbers in August 2012 using 2011 cost basis. Values in the NETL report are represented in 2007 dollars. For the purpose of cross-examining data among different sources, cost data presented here by ICF have been converted into 2011 dollars.[44]

The report presented results generated by the Aspen model, with some of the inputs based on sources such as the EIA's Annual Energy Outlook 2008. All power plants in the NETL study were assumed to be at a generic location in Midwestern U.S.[45] Power plants were assumed to

[43] NETL, Cost and Performance Baseline for Fossil Energy Plants, Page 52.
[44] See Inflation Schedule Appendix.
[45] NETL, Cost and Performance Baseline for Fossil Energy Plants, Page 31.

be land locked but with access to rail and highway, as well as equipped with off-site ash/slag disposal. The coal plants in this study were assumed to use either Illinois No. 6 or PRB as a fuel source. NETL estimated three main categories of costs: capital costs, operations and maintenance costs, and CO_2 transportation and storage costs.

NREL

In February 2012, Black & Veatch contracted with NREL to carry out a study on the power generating technology cost and performance. The report relied on sources published in late 2009 and 2010, and therefore NREL values are mostly represented in 2009 dollars. ICF converted these values into 2011 dollars for common comparison.[46]

All power plants in NREL's analysis are assumed to be in a reasonably level and clear location in the Midwestern United States.[47] Coal plants are assumed to use a Midwestern bituminous coal as the fuel, while gas plants are assumed to be single fuel while having natural gas readily available at the required pressure and volume.[48]

For the purpose of modeling, NREL assumes that cost trajectories do not dramatically rise or decline through 2050. Costs are assumed to be associated with technology maturity levels, and performance is expected to improve due to learning. NREL incorporated a linear cost improvement in its model.[49]

Labor costs and rates are similar to NETL assumptions.[50] Owner's costs were recorded as a separate line item, which includes operational spare parts, project insurance, construction permits, taxes, facility upgrades, costs of land and right-of-way access, permitting and licensing, and so on.[51] However, interests accrued during construction were excluded in the cost projection.[52]

EIA

The EIA contracted with R. W. Beck to develop a performance and cost assessment of power generation technologies. For coal plants, bituminous Illinois No. 6 coal from Old Ben Mine was assumed; for gas plants.[53]

The overnight capital costs for each type of technology installed in a typical greenfield location in the U.S., and regional differences such as local conditions and labor rates were reflected by a regional multiplier. In the base case analysis, costs were developed for each type of power

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[46] See Inflation Schedule Appendix.
[47] NREL Cost Report, Page 1. (Assumptions #2 and #3)
[48] NREL Cost Report, Page 2. (Assumption #12)
[49] NREL Cost Report, Page 1.
[50] NREL Cost Report, Page 2. (Assumptions #18 and #19)
[51] NREL Cost Report, Page 2-3 (Assumptions 24, 25, 26, 27, 28, 29, 30, 31)
[52] NREL Cost Report, Page 3. (Assumption 33)
[53] EIA, Updated Capital Cost Estimates for Electricity Generation Plants, Appendix A, 2-2 and 2-3.

generation technology based on a generic facility of a certain capacity and configuration in a non-specific location in the U.S. without unusual location impacts. Costs were represented in 2010 4th quarter US dollars. ICF converted these values from the EIA to 2011 dollars.[54]

For each technology, an EPC (turnkey) or equipment supply/balance of plant contracting approach was assumed when calculating capital costs, which would not usually result in the lowest cost of construction but an achievable cost of construction. Capital costs included the civil and structural costs, mechanical equipment supply and installation, electrical and I&C supply, project indirect costs, and owner's costs. Operation and maintenance expenses were categorized as followed: FOM, VOM, and major maintenance. Under operation and maintenance expenses, owner's expenses, including but not limited to property taxes, asset management fees, energy marketing fees, and insurance, were not addressed in the analysis. FOM included staffing and monthly fees, plant operator bonuses, equipment rentals and temporary labor, generation and administrative expenses, maintenance, and so on, while VOM comprises raw water, waste and wastewater disposal expenses, purchase power, demand charges and related utilities, chemicals, Ammonia for SCR, lubricants, and consumables.

Global CCS Institute

The Global CCS Institute relied on studies publicly available published by DOE, NETL, EPRI, EIA, and others, as well as the WorleyParsons database. The study selected a range of coal types as the basis for analysis, and the selection consisted one or two bituminous coals, one subbituminous coal, and a lignite coal. The typical heating rate of the coals assumed was on par with that of the Pittsburgh No. 8 coal.[55] All costs data were derived on the basis of a plant situated in a generic U.S. location, and did not reflect emission requirements and other constraints of a specific region.

[54] See Inflation Schedule Appendix.

[55] Global CCS Institute, Economic Assessment of Carbon Capture and Storage Technologies, Page 21.

3.4 Assessment of Coal Technologies by Type

Technology	**Subcritical Pulverized Coal**
Description	Coal is pulverized and burned in boilers in which heat is transferred to water in boiler tubes. Water is boiled into steam, whose temperature and pressure parameters are below the critical point. This subcritical steam is then used to generate electricity in a Rankine steam turbine.
CCS Option	For capturing CO_2 from pulverized coal plants, the best option is post-combustion CO_2 removal technology. Another option is to convert the subcritical units into boilers using oxygen-based combustion.
Maturity	The estimates for PC plants without CCS represent well-developed commercial technology, also known as "nth of a kind (NOAK)" plants. The post-combustion capture technology for PC plants is immature, as the technology is still unproven in commercial scale power generation units.
Benefits	Well known technology, with significant operational experience
Challenges	Efficiency is limited, as steam parameters are below the critical point. Emissions control continues to be a key challenge.
R&D and Future Prospects	Mature technology, with no need for R&D for basic technology. Emissions control technology continues to be developed to reduce a wide variety of emissions and effluents.
Plant Characteristics Assumptions for cost estimation	The subcritical PC plant in a Midwestern location has a steam cycle of 1800psig/1050°F/1050°F. Using Illinois No. 6 coal as a fuel source, the plant also has wet flue gas desulfurization (FGD)/Gypsum for the purpose of sulfur removal and recovery. Best available control technology is applied to PC plants. Control technologies installed include low NOx burners, overfire air, SCR, wet limestone scrubber, fabric filter, and co-benefit capture.
CCS Assumptions	The subcritical PC plant utilizes the Econamine post-combustion technology for CO_2 control, and the overall CO_2 capture efficiency is 90.2%. For CO_2 storage, the example plant uses an off-site saline formation.
Sources	NETL, Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 2, November 2010.

Technology	**Supercritical Pulverized Coal**
Description	Similar to a subcritical pulverized coal plant, except that the steam parameters are above the critical point of water. With increasing steam pressure and temperature, the efficiency of the steam turbines increases. Temperatures are typically around 1100°F and pressures less than 4000 psig.
CCS Option	For capturing CO_2 from pulverized coal plants, the best option is post-combustion CO_2 removal technology. Another option is to convert the supercritical pulverized units into boilers using oxygen-based combustion.
Maturity	The estimates for PC plants without CCS represent well-developed commercial technology, also known as "nth of a kind (NOAK)" plants. The post-combustion capture technology for PC plants is immature, as the technology is still unproven in commercial scale power generation units.
Benefits	Well known technology with higher efficiency than subcritical PC plants, which leads reduced coal use and emissions.
Challenges	Efficiency is only limited by metallurgy and cost. Emissions control continues to be a challenge, as emissions criteria are strengthened.
R&D and Future Prospects	Metallurgy is the key challenge such that the high temperature and pressures can be sustained. Emissions control technology continue to be developed to reduce a wide variety of emissions and effluents.
Plant Characteristics Assumptions	NETL:The supercritical PC plant in a Midwestern location has a steam cycle of 3500psig/1100°F/1100°F. Using Illinois No. 6 coal as a fuel source, the plant also has wet flue gas desulfurization (FGD)/Gypsum for the purpose of sulfur removal and recovery. Best available control technology is applied to PC plants. Control technologies installed include low NO_X burners, overfire air, SCR, wet limestone forced oxidation, fabric filter, and co-benefit capture. NREL: The supercritical PC plant in a generic Midwestern location has a single reheat, condensing, tandem-compound, four-flow steam turbine generator set, a wet mechanical draft cooling tower, SCR, low NO_X burners, and air quality control equipment for PM and acid gases all designed as typical recent U.S. installations. EIA: The supercritical PC plant in a Greenfield location operates at steam conditions of up to 3700psig/1050°F/1050°F. The plant employs a supercritical Rankine power cycle in which coal is burned to produce steam in a boiler. The steam is then condensed to water and pumped back to the boiler to be converted

	to steam once again. The plant also has wet flue gas desulfurization (wet FGD) and SCR.
CCS Assumptions	NETL assumes that the supercritical PC plant utilizes Econamine technology for CO_2 control, and the overall CO_2 capture efficiency is 90.2%. For CO_2 sequestration, the example plant uses an off-site saline formation. NREL analysis assumes that the removal efficiency to be 85%. The EIA sets the following off-site requirements for advanced pulverized coal with CCS facility. The sequestration of CO_2 takes place in one of the following geological formations: exhausted gas storage location, unminable coal seam, enhanced oil recovery, or saline aquifer.
Sources	NETL, Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 2, November 2010, Page 44. NREL, Cost and Performance Data for Power Generation Technologies, February 2012, Page 19. NREL, Cost and Performance Data for Power Generation Technologies, February 2012, Page 71. EIA, Updated Capital Cost Estimates for Electricity Generation Plants, 3-1. Global CCS Institute, Economic Assessment of Carbon Capture and Storage Technologies, 2011 Update, Page 7 and 35.

Technology	**Ultra-supercritical Pulverized Coal**
Description	Higher temperatures (>1200°F; >600°C) and higher pressures (>4000 psig) than supercritical PC. The transition from supercritical to ultrasupercritical is somewhat artificial.
CCS Option	For capturing CO_2 from pulverized coal plants, the best option is post-combustion CO_2 removal technology. Another option is to convert the subcritical units into boilers using oxygen-based combustion.
Maturity	As the ultra-supercritical technology is currently under development and therefore not commercially available yet, the estimates for ultra-supercritical PC plants represent first-of-a-kind costs. The post-combustion capture technology for PC plants is immature, as the technology is still unproven in commercial scale power generation units.
Benefits	Very high efficiency and reduced emissions.
Challenges	Metallurgy is the key challenge, in addition to utilizing lower rank coals to reach higher temperatures. Emissions control continues to be a challenge, as emissions criteria are strengthened.
R&D and Future Prospects	Aim is to reach a 700°C over time with advanced steel alloys. R&D is being led by Japan, Europe, China, and U.S. Emissions control technologies continue to be developed to reduce a wide variety of emissions and effluents.
Plant Characteristics Assumptions	The ultra-supercritical PC plant has a steam cycle of 4000psig/1200°F/1200°F. Using the Powder River Basin (PRB) subbituminous coal as a fuel source, the plant also has Spray Dryer FGD for the purpose of sulfur removal. The plant is also equipped with low NO_X burners, overfire air, SCR, fabric filter, carbon injection and co-benefit capture.
CCS Assumptions	NETL assumes that the technology used for CO_2 separation is Amine Absorber. The supercritical PC plant utilizes Econamine technology for CO_2 control, and the overall CO_2 capture efficiency is 90.2%. For CO_2 sequestration, the example plant uses an off-site saline formation.
Sources	NETL, Cost and Performance Baseline for Fossil Energy Plants, Volume 3b: Low Rank Coal to Electricity: Combustion Cases, March 2011, Page 2, 34, and 72. Global CCS Institute, Economic Assessment of Carbon Capture and Storage Technologies, 2011 Update, Page 7 and 35.

Technology	**Circulating Fluidized Bed (CFB)**
Description	Fluidized bed boilers can use bigger pieces of coal for combustion, as the residence time in the boilers is higher. Both subcritical and supercritical steam can be generated from the boilers.
CCS Option	For capturing CO_2 from CFB plants, the best option is post-combustion CO_2 removal technology. Another option is to convert the boilers into using oxygen-based combustion.
Maturity	CFB plants are well known mature technology, as long as they are using subcritical steam cycle. Large CFB plants with supercritical steam parameters represent technologies that have not been proven, thus treated as first-of-a-kind costs. The post-combustion CO_2 removal technology for PC plants is immature, as the technology is still unproven in commercial scale power generation units.
Benefits	Ability to use lower rank coal, including waste coal
Challenges	Advances in steam parameters to supercritical and ultrasupercritical regimes
R&D and Future Prospects	Continued R&D in U.S. and Europe on increasing efficiency, and oxyfuel-based combustion
Plant Characteristics Assumptions	The CFB plant has a supercritical steam cycle of 3500psig/1100°F/1100°F. Using the Powder River Basin subbituminous coal as a fuel source, the plant also has in-bed limestone injection for SO_2 control, combustion temperature control with overfire air and SNCR, fabric filter, and co-benefit capture.
CCS Assumptions	NETL assumes that the technology used for CO_2 separation is Amine Absorber. The supercritical PC plant utilizes Econamine technology for CO_2 control, and the overall CO_2 capture efficiency is 90.2%. For CO_2 sequestration, the example plant uses an off-site saline formation.
Sources	NETL, Cost and Performance Baseline for Fossil Energy Plants, Volume 3b: Low Rank Coal to Electricity: Combustion Cases, March 2011.

Technology	**Biomass Cofiring with Pulverized Coal**
Description	Use of biomass in combination with coal to reduce the GHG emissions from a coal power plant.
CCS Option	Technology for capturing CO_2 from biomass-based pulverized coal plants remains post-combustion CO_2 removal technology.
Maturity	Biomass co-firing with a small percentage has been demonstrated and is commercial. However, the challenge for higher percentages of biomass injected. While the technologies are commercial, demonstration is yet to be made on a large scale with high biomass content. The estimates for PC plants without CCS represent well-developed commercial technology, also known as "n^{th}-of-a-kind plants." The post-combustion CO_2 removal technology for PC plants is immature, as the technology is still unproven in commercial scale power generation units.
Benefits	Use of biomass can reduce the overall lifecycle GHG emissions from the coal plant. With CCS, the emissions can also turn negative.
Challenges	Large scale demonstration with high biomass input, as well as use of varied kinds of biomass
R&D and Future Prospects	Demonstration projects are underway in Europe and U.S.
Plant Characteristics Assumptions	The biomass cofiring supercritical PC plant co-feeds Hybrid Poplar biomass. The plant in the Greenfield location co-feeds 15% or 60% of biomass.
CCS Assumptions	NETL: The supercritical PC plant utilizes Econamine technology for CO_2 control, and the overall CO_2 capture efficiency is 90.2%. NREL: NREL treated biomass cofiring as a type of retrofit, and assumed a maximum of biomass injection to be 15% for all coal plants. As cost uncertainty is significantly impacted by the degree of modifications needed for a particular fuel and boiler combination, the report did not estimate any cost improvement over time.
Sources	NETL, Greenhouse Gas Reductions in the Power Industry Using Domestic Coal and Biomass Volume 2: Pulverized Coal Plants, Page 46 – 47. NREL, Cost and Performance Data for Power Generation Technologies, February 2012, Page 27.

Technology	**Chemical Looping Combustion (CLC)**
Description	A solid oxide (typically metal oxides) carrier is circulated between two interconnected fluidized-bed reactors. In the fuel reactor, the carrier is reduced by addition of fuel, which can be either gaseous or solid. The oxygen from the carrier is combined with the carbon and hydrogen in the fuel to make streams of CO_2 and water. The reduced carrier is then sent to the air reactor, where the carrier is oxidized by the addition of air. Hot vapors (mostly nitrogen) exiting the air reactor can be used to raise steam or fed directly to a gas turbine.
CCS Option	CO_2 capture is inherent to this process. Air does not mix with the fuel. Therefore, the effluent from the fuel reactor is primarily CO_2 plus water, which are easily separated.
Maturity	This is an immature technology, existing only in the pilot scale. The largest scale tested is on the order of 100s kW fuel input. To date, there has been much more experience with gaseous fuels than solid fuels.
Benefits	Dramatically reduces the energy penalty associated with CCS. Theoretically can eliminate capture energy penalty and just require energy for compression.
Challenges	Much more complex system than pulverized coal or gas turbine technologies. Key challenge is the choice of oxygen carrier, which must undergo hundreds or thousands of oxidation/reduction cycles without degradation. It is reported that nickel-based carriers have best performance characteristics, but may prove too expensive. Recent R&D looking more at calcium-based carriers, especially for solid fuels where separating the carrier from the ash is a challenge.
R&D and Future Prospects	Focus is on scaling up the pilot tests, as well as identifying good solid oxide carriers. There is significant effort on understanding the fluid dynamics within the reactors. Handling of solids and control of reactions is being studied. If successful, CLC can significantly lower CCS costs. However, there are many challenges to overcome before that is achieved.
Plant Characteristics Assumptions	Given the immature state of the technology, it is too premature to give credible cost estimates. However, some studies claim that CLC can significantly reduce costs of CCS compared to both post-combustion capture and pre-combustion capture routes, due primarily to the lower energy penalty.
CCS Assumptions	Only compression and dehydration for effluent from fuel reactor is needed.

Sources	Mohammad M. Hossain, Hugo I. de Lasa, Chemical-looping combustion (CLC) for inherent separations—a review, Chemical Engineering Science, Volume 63, Issue 18, September 2008, Pages 4433-4451, ISSN 0009-2509, 10.1016/j.ces.2008.05.028. (http://www.sciencedirect.com/science/article/pii/S0009250908002947) See also: http://www.globalccsinstitute.com/get-involved/webinars/2012/07/11/carbon-capture-and-chemical-looping-technology-update-progress

Technology	**Integrated Gasification Combined Cycle (IGCC)**
Description	Coal is first gasified using steam and oxygen to produce a low-energy synthetic gas, which then sent into a combined cycle power plant. Steam from the syngas cooler is also integrated with stream turbine. In addition to the steam cycle integration, compressed air (obtained from a compressor running off the gas turbine shaft) can also be integrated with the air separation unit that produces the required oxygen.
CCS Option	Pre-combustion CO_2 removal (e.g., using Selexol) from syngas streams has proven itself in chemical processes in conditions similar to that of IGCC plants. For capture rates above 20-30%, pre-combustion capture will require water-gas shift reactors prior to the CO_2 removal process. These reactors are mature technology.
Maturity	The estimates for IGCC plants were also based on commercial offerings. Since the sales have been limited, IGCC plant costs are treated at the "next commercial offering" level. The pre-combustion CO_2 removal for IGCC plants presents a stronger commercial experience base (e.g., ammonia production). However, it has not been demonstrated in IGCC plants, but there are IGCC plants with CCS currently under planning stages.
Benefits	Higher efficiency and reduced emissions; cost of CO_2 capture is much cheaper than in PC plants as CO_2 is captured before combustion from the syngas.
Challenges	IGCC plants are significantly more expensive than PC plants, so cost reduction of IGCC plants is critical. Moreover, large scale operations and integration of all systems are key challenges.
R&D and Future Prospects	Significant R&D is being invested to develop IGCC and capture technologies in U.S., Europe, and China.
Plant Characteristics Assumptions	NETL: The IGCC plant has a steam cycle of 1800psig/1050°F/1050°F using the GEE Radiant Only gasifier/boiler technology. Using the Illinois No. 6 coal as a fuel source, the plant operates 2 Advanced F Class combustion turbines. The unit also installs multiple pollutant controls: Wet FGD/Gypsum, Selexol for H2S separation, Multi Nozzle Quiet Combustor and N2 Dilution, water quench, scrubber, AGR absorber, and carbon bed. NREL: The IGCC analysis is based on a commercial gasification process integrated with a conventional combined cycle plant with a wet cooling tower. EIA: The IGCC analysis is based on a plant equipped with an advanced combustion turbine, HRSGs, and

	gasifiers. GCCSI: The IGCC analysis is based on dry-feed Shell Technology.
CCS Assumptions	NETL: For CO_2 separation, the plant uses Selexol 2nd stage technology, and CO_2 sequestration process takes place in an off-site saline formation. NREL: NREL assumes an 85% carbon removal efficiency rate.
Sources	NETL, Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 2, November 2010, Page 44. NREL, Cost and Performance Data for Power Generation Technologies, February 2012, Page 21 – 23. EIA. Annual Energy Outlook 2012 Assumptions, August 2012, Page 94 – 95. Global CCS Institute, Economic Assessment of Carbon Capture and Storage Technologies, 2011 Update, Page 7 and 35.

Technology	**Natural Gas Combined Cycle (NGCC)**
Description	Gas is combusted in a turbine, and steam produced from cooling the gas is used in a combined cycle steam turbine.
CCS Option	For capturing CO_2 from NGCC plants, the best option is post-combustion CO_2 removal technology. Another option is to convert the subcritical units into boilers using oxygen-based combustion.
Maturity	The estimates for NGCC plants without CCS represent well-developed commercial technology, also known as "n^{th} plants." The post-combustion CO_2 removal technology for NGCC plants is immature, as the technology is still unproven in commercial scale power generation units.
Benefits	Faster construction time, and reduced emissions
Challenges	None
R&D and Future Prospects	NGCC is already a mature technology.
Plant Characteristics Assumptions	NETL: The example NGCC plant has a steam cycle of 2400psig/1050°F/1050°F. Using natural gas as the main fuel source, the plant's gasifier/boiler technology is HRSG. The plant also incorporates low NO_X burners and SCR. NREL: The example NGCC plant utilizes to GE 7FA combustion turbines as well as two HRSGs. The plant also installs a wet mechanical draft cooling tower. EIA: The example NGCC plant is equipped with an advanced combustion turbine and HRSG.
CCS Assumptions	NETL: The NGCC plant utilizes Econamine technology for CO_2 control, and the overall CO_2 capture efficiency is 90.2%. For CO_2 sequestration, the example plant uses an off-site saline formation. NREL: NREL assumes a carbon removal efficiency rate of 85%.
Sources	NETL, Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 2, November 2010, Page 44.

	NREL, Cost and Performance Data for Power Generation Technologies, February 2012, Page 15. EIA, Annual Energy Outlook 2012 Assumptions, August 2012, Page 94 – 95. Global CCS Institute, Economic Assessment of Carbon Capture and Storage Technologies, 2011 Update, Page 7 and 35.

Technology	**Coal to Synthetic Gas (Coal to SNG)**
Description	Coal is gasified using steam and oxygen to produce a synthetic gas (SNG) that can be sold as a substitute for natural gas.
CCS Option	Pre-combustion CO_2 removal from syngas has proven itself in chemical processes in conditions similar to that of coal to SNG plants.
Maturity	The estimates for coal to SNG plants represent costs based on commercial offerings. Since the sales have been limited, coal to SNG plant costs are less mature in the learning curve, which was reflected as the “next commercial offering” level. Pre-combustion CO_2 removal from syngas has been demonstrated at the Great Plains Synfuel plan and in hundreds of syngas processing plants ammonia, methanol, hydrogen, and other petrochemical plants worldwide.
Benefits	If natural gas is expensive then coal to SNG can present advantageous opportunities to expand coal into the natural gas market. This is currently the situation in Asia, but not the US. Shale gas development in the US portends a prolonged period of relatively low gas prices.
Challenges	Low price of gas
R&D and Future Prospects	Gasification of coal, by itself, is a mature technology, and it unlikely there will be significant R&D given the alternative of natural gas.
Plant Characteristics Assumptions	The coal to SNG plant has a steam cycle of 1800psig/1050°F/1000°F using the Siemens gasifier technology. Using the Illinois No. 6 coal as a fuel source,l the plant operates multiple pollutant controls: Selexol for H2S separation, Multi Nozzle Quiet Combustor and N2 Dilution, scrubber, AGR absorber, and carbon bed.
CCS Assumptions	For CO_2 separation, the plant uses Selexol 2^{nd} stage technology, and CO_2 sequestration process takes place in an off-site saline formation.
Sources	NETL, Cost and Performance Baseline for Fossil Energy Plants, Volume 2: Coal to Synthetic Natural Gas and Ammonia.

3.5 Cost and Performance Data (2011 US Dollars)—without CCS

*Unless otherwise noted, NETL assumes the source of coal as Illinois No. 6 bituminous coals.

ICF cross-examined three major categories of costs from four major sources: NETL, NREL, EIA, and the Global CCS Institute. All four sources provide data on the following power generation technologies: supercritical pulverized coal, IGCC, and NGCC, and the numbers extracted from several publications vary significantly in some cases.

Under the category of supercritical pulverized coal, NETL's estimates, when Illinois No. 6 coal is the fuel source, have a total overnight cost of $2617/kW, while NREL presents a cost of $2986/kW. On the other hand, the Global CCS Institute's estimates of capital costs - $1960/kW – are significant lower than all other sources. Similar trend also appears when examining costs from various sources under the category of IGCC plants and NGCC plants. In other words, for fossil fuel plants, NREL usually presents the highest cost estimates, while the Global CCS Institute has the lowest, and NETL's estimates fall between the two ends. Based on description of assumptions of the supercritical plant under examination, NETL provides a most detailed account of plant information. NETL provides the most transparent data and assumptions among all of the sources considered in this study.[56] Exhibit 40 collect available cost and performance information from four sources.

[56] It is also worth noting that, besides cost estimates, other performance metrics such as heat rate assumptions made by the NREL study can appear questionable. For instance, the heat rate for supercritical PC plants from NREL is 9,370 Btu/kWh, which is significantly higher than that of NETL, EIA, or GCCSI. Moreover, this particular heat rate of a supercritical plant is higher than the assumed subcritical PC plant heat rate in NETL analysis.

Exhibit 40: Cost and Performance Data (without CCS)

Pulverized Coal – Subcritical

	Gross Cap.	Internal Load	Net Cap.	Internal Consumption	Cap. Factor	Heat Rate	Capital costs	VOM	FOM
	MW	MW	MW	%	%	Btu/kWh	$/kW	$/MWh	$/kW
NETL	582.6	32.58	550.02	6	85	9276	2583	8.5	74

Pulverized Coal – Supercritical

	Gross Cap.	Internal Load	Net Cap.	Internal Consumption	Cap. Factor	Heat Rate	Capital costs	VOM	FOM
	MW	MW	MW	%	%	Btu/kWh	$/kW	$/MWh	$/kW
NETL	580.4	30.41	549.99	5	85	8686	2617	8.3	75
NETL-PRB[1]	582.7	32.66	550.04	6	85	8813	2967	6.6	87
NREL	--	--	606	--	85	9370	2986	3.8	24
EIA	--	--	1300	--	85	8800	2905	4.3	30
GCCSI	580	30	550	5	--	8907	1960	4.9	36

1. Fuel source assumed in this case was Powder River Basin subbituminous coal.

Pulverized Coal – Ultra-supercritical

	Gross Cap.	Internal Load	Net Cap.	Internal Consumption	Cap. Factor	Heat Rate	Capital costs	VOM	FOM
	MW	MW	MW	%	%	Btu/kWh	$/kW	$/MWh	$/kW
NETL[2]	581.5	31.43	550.07	5	85	8552	3112	6.6	90
GCCSI	576.6	26.6	550	5	--	7592	2056	4.4	36

2. Fuel source assumed in this case was Powder River Basin Subbituminous coal.

Circulating Fluidized Bed (CFB)

	Gross Cap.	Internal Load	Net Cap.	Internal Consumption	Cap. Factor	Heat Rate	Capital costs	VOM	FOM
	MW	MW	MW	%	%	Btu/kWh	$/kW	$/MWh	$/kW
NETL[3]	578.4	28.33	550.07	5	85	8770	3050	6.9	88

3. Fuel source assumed in this case was Powder River Basin Subbituminous coal.

Biomass Cofiring with Pulverized Coal

	Gross Cap.	Internal Load	Net Cap.	Internal Consumption	Cap. Factor	Heat Rate	Capital costs	VOM	FOM
	MW	MW	MW	%	%	Btu/kWh	$/kW	$/MWh	$/kW
NETL[4]	582.7	32.67	550.03	6	85	8739	2672	7.2	78
NETL[5]	594	44.01	549.99	7	85	8998	2843	7.1	81
NREL[6]	--	--	--	--	85	10000	1023	0.00	21

4. This case was based on 15% biomass weight.
5. This case was based on 60% biomass weight.
6. This case was based only on the retrofit part with 15% biomass weight.

Integrated Gasification Combined Cycle (IGCC)

	Gross Cap.	Internal Load	Net Cap.	Internal Consumption	Cap. Factor	Heat Rate	Capital costs	VOM	FOM
	MW	MW	MW	%	%	Btu/kWh	$/kW	$/MWh	$/kW
NETL	747.8	125.75	622.05	17	80	8756	3168	10.0	101
NREL	--	--	590	--	85	9030	4349	6.8	32
EIA	--	--	1200	--	85	8700	3289	7.0	50
GCCSI	748	112	636	15	--	8303	2674	4.7	61

Natural Gas Combined Cycle

	Gross Cap.	Internal Load	Net Cap.	Internal Consumption	Cap. Factor	Heat Rate	Capital costs	VOM	FOM
	MW	MW	MW	%	%	Btu/kWh	$/kW	$/MWh	$/kW
NETL	564.7	9.62	555.08	2	85	6798	951	1.9	29
NREL	--	--	615	--	87	6750	1271	4.0	6.5
EIA	--	--	400	--	87	6430	949	3.2	15
GCCSI	570	10	560	2	--	6720	726	1.2	14

Coal to Synthetic Gas

	Gas Output	Gross Cap.	Internal Load	Net Cap.	Power Consum-ption	Cap. Factor	Conver-sion Efficiency	Cap. costs	VOM	FOM
	MMBtu/hr	MW	MW	MW	%	%	%	000 $	$/MMBtu	$/MMBtu/yr
NETL	6892	308	216.35	91.65	70	90	61.4	4185940	0.34	2.28
NETL[7]	6789	302	247.57	54.43	82	90	63.1	4340141	0.72	2.38

7. Fuel source assumed in this case was Powder River Basin subbituminous coal

3.6 Cost and Performance Data (2011 US Dollars)—with CCS

*Unless otherwise noted, NETL assumes the source of coal as Illinois No. 6 bituminous coals.

ICF cross-examined three major categories of coal technologies costs with CCS from four major sources: NETL, NREL, EIA, and the Global CCS Institute. Almost all sources provide data on the following power generation technologies: supercritical pulverized coal, IGCC, and NGCC, and the numbers extracted from several publications vary significantly in some cases.

Under the category of supercritical pulverized coal, NETL's estimates, when Illinois No. 6 coal is the fuel source, have a total overnight cost of $4686/kW, while NREL presents a cost of $6777/kW. On the other hand, the Global CCS Institute's estimates of capital costs - $3538/kW – are significant lower than all other sources. Similar trend also appears when examining costs from various sources under the category of IGCC plants and NGCC plants. In other words, for fossil fuel plants with CCS technologies, NREL usually presents the highest cost estimates, while the Global CCS Institute has the lowest, and NETL's estimates fall between the two ends.

Based on description of assumptions of the supercritical plant under examination, NETL provides a most detailed account of plant information. Given that NREL advocates for renewable energy development, and the Global CCS Institute promotes the advancement of CCS technology especially with coal plants, ICF considered NETL assumptions as the most transparent and reliable. Exhibit 41 shows the cost and performance data from four sources.

Exhibit 41: Cost and Performance Data (with CCS)

Pulverized Coal – Subcritical + CCS

	Gross Capacity	Internal Load	Net Capacity	Internal Consumption	CCS Penalty	Capacity Factor	Heat Rate	Capital costs	VOM	FOM
	MW	MW	MW	%	%	%	Btu/kWh	$/kW	$/MWh	$/kW
NETL	672.7	122.74	549.96	18	13	85	13044	4736	14.9	125

Pulverized Coal – Supercritical + CCS

	Gross Capacity	Internal Load	Net Capacity	Internal Consumption	CCS Penalty	Capacity Factor	Heat Rate	Capital costs	VOM	FOM
	MW	MW	MW	%	%	%	Btu/kWh	$/kW	$/MWh	$/kW
NETL	662.8	112.83	549.97	17	12	85	12002	4686	14.1	124
NETL[8]	673	122.94	550.06	18	13	85	12634	5231	12.2	142
NREL	--	--	455	--	--	85	12100	6777	6.2	37
GCCSI	663	117	546	18	12	--	--	3538	9.1	56

8. Fuel source assumed in this case was Powder River Basin subbituminous coal.

Pulverized Coal – Ultra-supercritical + CCS

	Gross Capacity	Internal Load	Net Capacity	Internal Consumption	CCS Penalty	Capacity Factor	Heat Rate	Capital costs	VOM	FOM
	MW	MW	MW	%	%	%	Btu/kWh	$/kW	$/MWh	$/kW
NETL[9]	665.4	115.32	550.08	17	12	85	11898	5312	11.9	143
GCCSI	644.4	94.4	550	15	10	--	--	3477	8.0	51

9. Fuel source assumed in this case was Powder River Basin Subbituminous coal.

Circulating Fluidized Bed (CFB) + CCS

	Gross Capacity	Internal Load	Net Capacity	Internal Consumption	CCS Penalty	Capacity Factor	Heat Rate	Capital costs	VOM	FOM
	MW	MW	MW	%	%	%	Btu/kWh	$/kW	$/MWh	$/kW
NETL[10]	**664**	**113.99**	**550.01**	**17**	**12**	**85**	**12476**	**5271**	**12.4**	**141**

10. Fuel source assumed in this case was Powder River Basin Subbituminous coal.

Biomass Cofiring with Pulverized Coal + CCS

	Gross Capacity	Internal Load	Net Capacity	Internal Consumption	CCS Penalty	Capacity Factor	Heat Rate	Capital costs	VOM	FOM
	MW	MW	MW	%	%	%	Btu/kWh	$/kW	$/MWh	$/kW
NETL[11]	**678.4**	**128.38**	**550.02**	**19**	**13**	**85**	**12667**	**4901**	**12.0**	**1296**
NETL[12]	**684.8**	**134.76**	**550.04**	**20**	**12**	**85**	**12853**	**5004**	**12.0**	**131**

11. This case was based on 15% biomass weight.

12. This case was based on 60% biomass weight.

Integrated Gasification Combined Cycle (IGCC) + CCS

	Gross Capacity	Internal Load	Net Capacity	Internal Consumption	CCS Penalty	Capacity Factor	Heat Rate	Capital costs	VOM	FOM
	MW	MW	MW	%	%	%	Btu/kWh	$/kW	$/MWh	$/kW
NETL	**734**	**190.75**	**543.25**	**26**	**9**	**80**	**10458**	**4360**	**12.9**	**134**
NREL	**--**	**--**	**520**	**--**	**--**	**85**	**11800**	**6818**	**11.0**	**46**
EIA	**--**	**--**	**520**	**--**	**--**	**85**	**10700**	**4956**	**8.2**	**71**
GCCSI	**693**	**176**	**517**	**25**	**10**	**--**	**--**	**3486**	**2.4**	**25**

Natural Gas Combined Cycle + CCS

	Gross Capacity	Internal Load	Net Capacity	Internal Consumption	CCS Penalty	Capacity Factor	Heat Rate	Capital costs	VOM	FOM
	MW	MW	MW	%	%	%	Btu/kWh	$/kW	$/MWh	$/kW
NETL	**511**	**37.43**	**473.57**	**7**	**6**	**85**	**7968**	**1966**	**3.7**	**54**
NREL	**--**	**--**	**580**	**--**	**--**	**87**	**10080**	**3874**	**10.3**	**19**
EIA	**--**	**--**	**340**	**--**	**--**	**87**	**7525**	**1873**	**6.6**	**31**
GCCSI	**520**	**38**	**482**	**7**	**6**	**--**	**--**	**1478**	**2.4**	**25**

Coal to Synthetic Gas + CCS

	Gas Output	Gross Capacity	Internal Load	Net Capacity	Power Consumption	CCS Penalty	Capacity Factor	Conversion Efficiency	Capital costs	VOM	FOM
	MMBtu/hr	MW	MW	MW	%		%	%	000 $	$/MMBtu	$/MMBtu-yr
NETL	**6866**	**310.6**	**262.09**	**48.51**	**84**	**14**	**90**	**61.3**	**4346065**	**0.83**	**2.35**
NREL[13]	**6784**	**302**	**300.19**	**1.81**	**99**	**17**	**90**	**63.1**	**4516051**	**1.33**	**2.44**

13. Fuel source assumed in this case was Powder River Basin subbituminous coal.

3.7 Levelized cost for cross-technology comparison

In order to provide a direct comparison of costs across a variety of technologies, ICF calculated the levelized costs for different power generation technologies in the year 2018. A separate calculation is made for the technologies to account for the inclusion of CCS. When CCS technology is incorporated, CO_2 transportation, storage and monitoring costs are not included in the calculation—only capture of CO_2. NETL, for example, adds the cost of CO_2 transport, storage and monitoring in its cost of electricity calculation separately. However, costs incurred by CO_2 removal system and CO_2 compression and drying system are included in the analysis.

In order to calculate levelized costs, ICF used the following assumptions:

Capital Charge Rate

ICF used the (real) capital charge rate (CCR) from EIA's annual energy outlook 2012. According to EIA's analysis, CCR for PC and IGCC plants in 2017 is 16.6%, while the rate for CC plants in 2017 is 11.9%.

Fuel Costs

ICF relied on delivered fuel prices for electricity sector from EIA's AEO2012. For 2018, the delivered coal price in 2011$ is assumed to be $2.61/MMBtu, and the delivered natural gas price is assumed to be $4.71/MMBtu.

Below is an illustrative result from the levelized cost calculations for a pulverized supercritical plant using Illinois No. 6 coal. ICF used NETL assumptions (as noted above) for the calculation:

Assumptions	Value
Typical Capacity (MW)	550
Capital Charge Rate (CCR)	16.60%[57]
Capacity Factor	85%
Heat Rate (Btu/kWh)	8686
Capital Costs (2011$/kW)	2617
VOM (2011$/kWh)	8.26
FOM (2011$/kW-yr)	75
Fuel Costs ($/MMBtu)	2.61

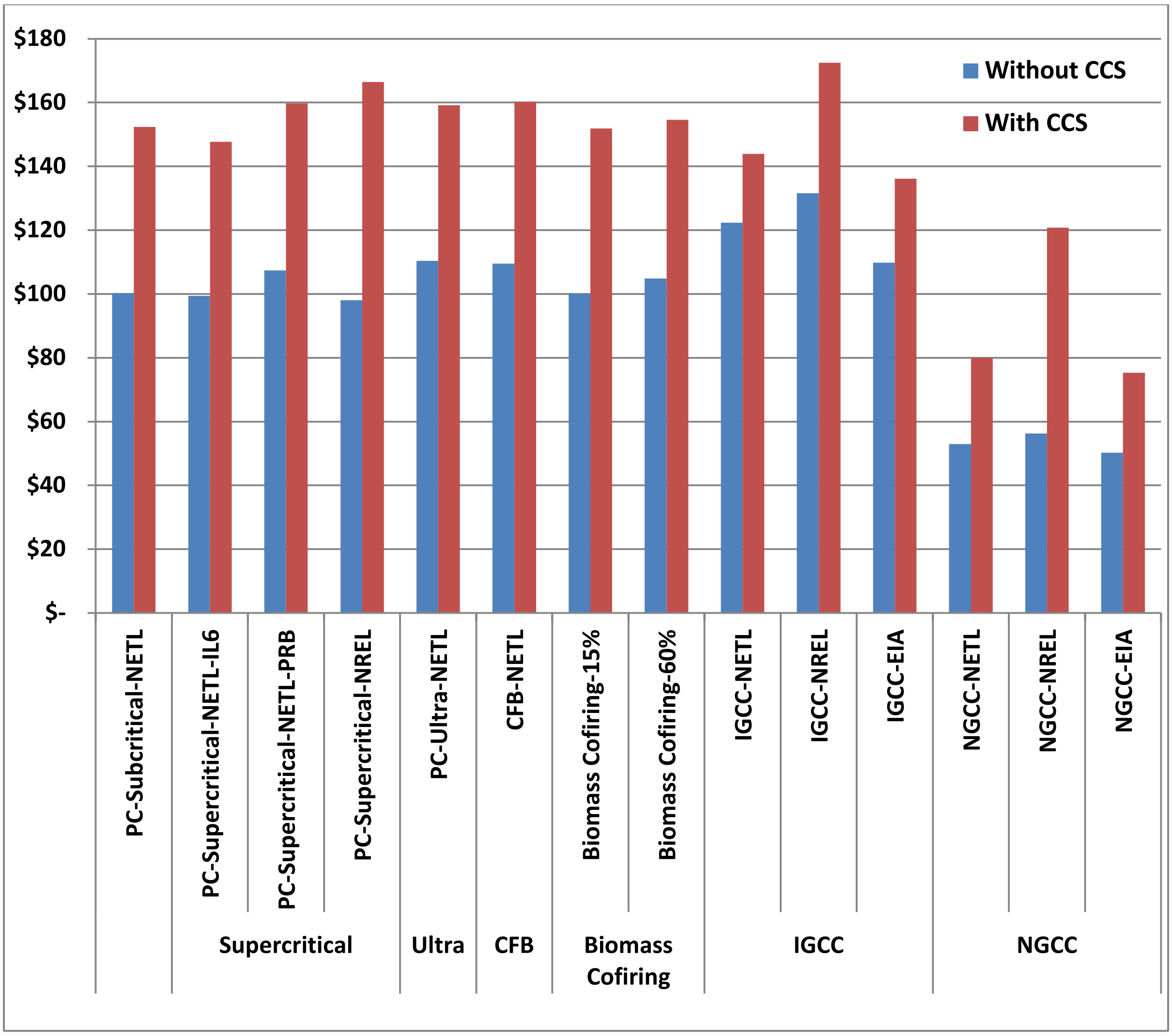
Calculations	For Year 2018
Annualized Capital Charges ($/kW-yr)	434 (=2617*16.60%)
Total Fixed Costs ($/kW-yr)	510 (=434+75)

[57] The high capital charge rate of 16.6% is only applied to coal-fired plants without CCS. When CCS is incorporated into a plant, the capital charge rate is 13.6%. The 3% difference represents the costs associated with carbon emissions.

Total Fixed Costs ($/MWh)	**68.46 (=510*1000/24/365/85%)**
Fuel Costs ($/MWh)	**22.67 (=2.61*8686/1000)**
Total Variable Costs ($/MWh)	**30.93 (=8.26+22.67)**
Total Levelized Costs ($/MWh)	**99.39 (=68.46+30.93)**

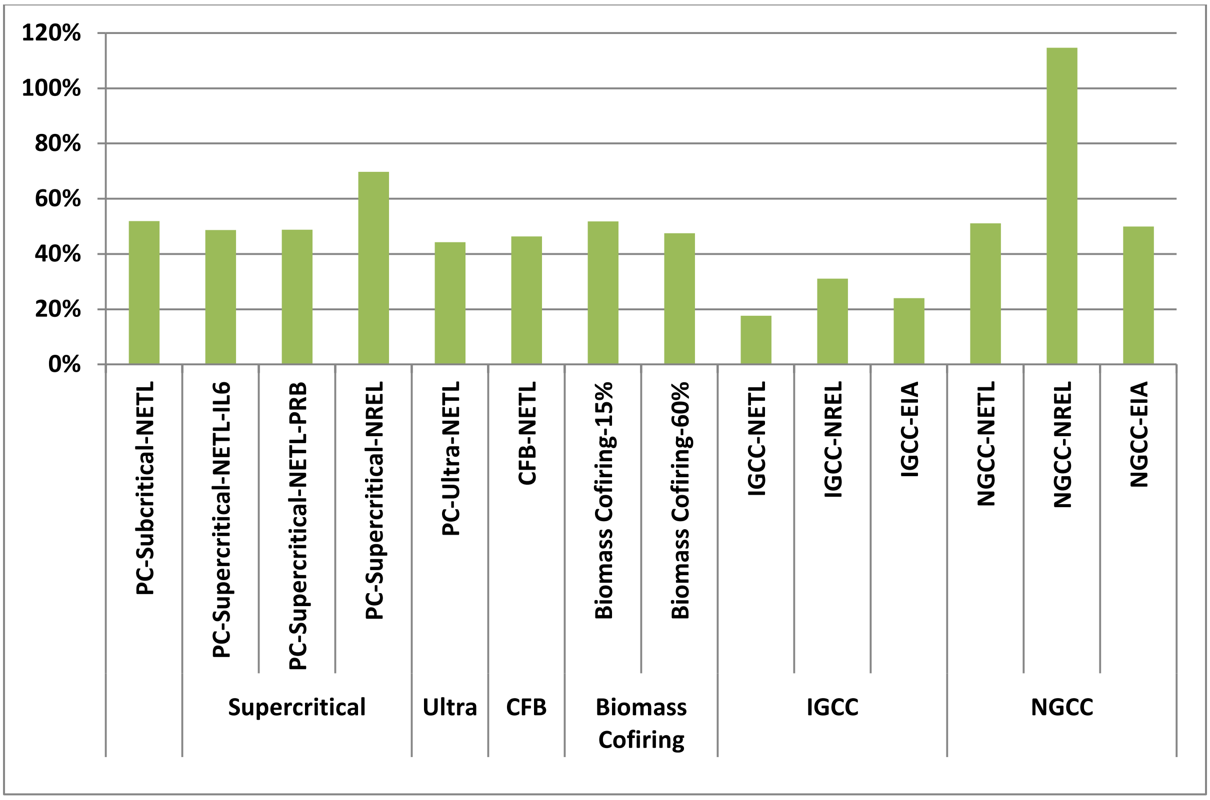
The following exhibits illustrate levelized cost of energy for each type of power generation technology with and without CCS for power plants as defined by the various sources.

Exhibit 42: Levelized Cost of Electricity of Various Types of Generating Technologies for 2018



Among all coal technologies without CCS, subcritical, supercritical, and biomass cofiring have similar levelized costs. Ultra-supercritical and CFB plants have a higher level of levelized costs. IGCC plants are the most expensive among all coal technologies, due to their relative lower maturity level. But as discussed above, IGCC has a greater potential for cost reduction by learning. Compared to NGCC plants, LCOE of coal technologies are two to three times more expensive.

Exhibit 43: Increase in Percentage with CCS technologies for 2018



With CCS, cost of electricity from pulverized coal plants is between 50% - 70% higher than without CCS. Levelized costs for IGCC plants with CCS are lower (~18%) under NETL assumptions. The EIA's assumptions suggest that the LCOE increase for IGCC is about 24%.

The addition of CCS to NGCC plants results in a cost increase of about 51% based on NETL assumptions. On the other hand, NREL's assumptions for CCS with NGCC suggests a much higher increase in capital cost, resulting in a much higher increase in LCOE (115%).

Addition of CCS to CFB plants and PC plants with biomass-cofiring plants results in an increase in cost of electricity comparable to the underlying PC plant.

3.8 Demonstration and Commercial Projects

Demonstration of CCS is critical for its future success in deployment—however, the interest in demonstration (as well as the subsequent commercial deployment) is very much dependent on a stable and relatively high price for CO_2 emissions (which does not exist at present).

IGCC is being demonstrated, but its high cost has slowed down the interest in commercial deployment. However, pulverized coal, CFB, and biomass injection have been demonstrated and are commercially deployed. There are a number of demonstration projects in the US that are currently under progress for supporting the deployment of coal power technologies. The following below is a brief summary.

1. CCS Demonstration Projects

The Global CCS Institute provides a list of currently operating integrated CCS projects across the globe.[58] However, none of the four operating projects in the U.S. is associated with power generation. Exhibit 44 briefly summarizes CCS project information.

Exhibit 44: Current Power Generation CCS Projects in the U.S.

Project Name	State	Operation Date	Facility Details	Capture Type
Century Plant	Texas	2010	Natural Gas Processing	Pre-Combustion (inc. Gas Processing)
Enid Fertilizer CO_2-EOR Project	Oklahoma	1982	Fertilizer Production	Pre-Combustion (inc. Gas Processing)
Shut Creek Gas Processing Facility	Wyoming	1986	Natural Gas Processing	Pre-Combustion (inc. Gas Processing)
Val Verde Natural Gas Plants	Texas	1972	Natural Gas Processing	Pre-Combustion (inc. Gas Processing)
Great Plains Synfuel Plant and Weyburn-Midale Project	North Dakota	2000	Synthetic Natural Gas	Pre-Combustion (inc. Gas Processing)

Source: MIT, Carbon Capture and Sequestration Project Database

2. IGCC Demonstration Plants

According to the 2010 Worldwide Gasification Database[59] managed by NETL, There are two IGCC units currently operating within the Eastern Interconnection, and one additional plant is under construction. Exhibit 45 briefly summarizes the status of IGCC plants within the Eastern Interconnection.

Exhibit 45: IGCC Demonstration Projects in the EI

Plant Name	Plant State	Capacity (MW)	Fuel Source	NERC Region	Status
Polk Station	Florida	326.3	Bituminous	FRCC	Operating
Wabash River	Indiana	304.5	Bituminous	RFC	Operating
Plant Ratcliffe	Mississippi	600	Lignite	SERC	Under Construction
Edwardsport	Indiana	618	Coal	RFC	Under Construction

Source: SNL Briefing Book

[58] http://www.globalccsinstitute.com/publications/global-status-ccs-2012
[59] http://www.netl.doe.gov/technologies/coalpower/gasification/worlddatabase/index.html

3. Subcritical PC Commercial Plants

Exhibit 46 using the Platts UDI database illustrates the number of subcritical units within the Eastern Interconnection, and the total nameplate capacity covered by these subcritical PC units by state.[60]

Exhibit 46: Subcritical PC Units in the Eastern Interconnection

State	# of Units	Capacity (MW)	State	# of Units	Capacity
AL	35	9,959	MT	1	50
AR	6	4,678	NC	46	9,127
CA	-	-	ND	12	4,169
CT	1	400	NE	14	3,982
DC	-	-	NH	3	509
DE	5	969	NJ	7	1,541
FL	32	11,693	NM	-	-
GA	26	7,900	NY	18	2,729
IA	35	6,172	OH	37	7,718
IL	60	17,203	OK	10	4,660
IN	49	11,991	PA	50	7,255
KS	15	4,804	RI	-	-
KY	50	14,698	SC	29	6,349
LA	6	3,726	SD	1	475
MA	6	958	TN	30	6,230
MD	13	2,879	TX	10	4,648
ME	1	102	VA	34	5,524
MI	48	8,588	VT	-	-
MN	21	4,208	WI	34	6,307
MO	32	10,288	WV	22	4,026
MS	6	2,496	Total	805	199,049

Source: Platts UDI Database

[60] UDI World Electric Power Plants Data Base (WEPP), March 2011.

4. Supercritical PC Commercial Plants

Exhibit 47 illustrates the number of supercritical units within the Eastern Interconnection, and the total nameplate capacity covered by these supercritical PC units by state.[61]

Exhibit 47: Supercritical PC Units in the Eastern Interconnection

State	# of Units	Capacity (MW)	State	# of Units	Capacity
AL	3	2,530	MT	-	-
AR	-	-	NC	4	3,570
CA	-	-	ND	-	-
CT	-	-	NE	-	-
DC	-	-	NH	-	-
DE	-	-	NJ	1	620
FL	-	-	NM	-	-
GA	8	6,491	NY	-	-
IA	1	890	OH	16	12,564
IL	-	-	OK	2	915
IN	11	8,046	PA	17	12,655
KS	1	893	RI	-	-
KY	2	1,967	SC	3	1,432
LA	-	-	SD	-	-
MA	1	650	TN	3	3,550
MD	5	2,321	TX	-	-
ME	-	-	VA	-	-
MI	5	3,655	VT	-	-
MN	1	598	WI	4	2,191
MO	4	2,439	WV	13	10,437
MS	-	-	Total	105	78,423

Source: Platts UDI Database

5. Ultra-supercritical PC Commercial Plants

Currently there are no operating ultra-supercritical PC plants, as the Eddystone power plant has been shut down. However, there are three units that are under development within the Eastern Interconnection, as shown in Exhibit 48[62]:

[61] UDI World Electric Power Plants Data Base (WEPP), March 2011.
[62] UDI World Electric Power Plants Data Base (WEPP), March 2011.

Exhibit 48: Ultra-supercritical PC Units in the Eastern Interconnection

Unit	Capacity (MW)	City	State	NERC Region
Glades Power Park 1	1070	Moore Haven	FL	FRCC
Glades Power Park 2	1070	Moore Haven	FL	FRCC
John W Turk Jr 1	672	Fulton	AR	SPP

Source: Platts UDI Database

6. CFB commercial plants

Exhibit 49 illustrates the number of CFB units within the Eastern Interconnection, and the total nameplate capacity covered by these supercritical PC units by state.[63]

Exhibit 49: CFB Units in the Eastern Interconnection

State	# of Units	Capacity (MW)	State	# of Units	Capacity
AL	-	-	MT	-	-
AR	-	-	NE	-	-
CT	-	-	NH	-	-
DE	-	-	NJ	-	-
FL	3	887	NY	-	-
GA	-	-	NC	1	28
IL	11	496	ND	1	75
IN	-	-	OH	1	141
IA	6	306	OK	2	350
KS	-	-	PA	16	1,687
KY	2	659	SC	-	-
LA	4	991	SD	-	-
MD	1	229	TN	-	-
MA	-	-	TX	-	-
MI	4	83	VA	1	668
MN	-	-	WV	1	96
MS	1	514	WI	5	171
MO	-	-	Total	60	7,376

Source: Platts UDI Database

[63] Data from Ventyx via Velocity Suite Online, Investment Grade Data & Analysis.

3.9 Inflation Schedule Appendix

The following inflation schedule is utilized throughout ICF's analysis.

Year	Inflation (Source: ICF)
2007	2.90%
2008	2.22%
2009	1.06%
2010	1.15%
2011	2.13%

Task 4: Environmental Retrofits and Retirement

4.1 Introduction

In Task 4, ICF evaluated the cost and performance of environmental retrofits and plant-life extensions for power generation facilities, focusing primarily on environmental retrofits applicable to pulverized coal plants. ICF relied on data from EPA's IPM analyses of the Cross-State Air Pollution Rule (CSAPR) and Mercury and Air Toxics standards (MATS) to quantify the cost and performance of various retrofit technologies. – specifically, the levelized capital, fixed operation and maintenance (FOM), variable operation and maintenance (VOM), and fuel costs to enable direct comparison among the various combinations of retrofits. In quantifying the cost and nature of plant-life extensions, this section relied on information from EPA's latest IPM analyses. EPA provides data on life extension costs for a number of power generation technologies, including: coal steam, combined cycle, combustion turbine and internal combustion engine, oil/gas steam, IGCC, and nuclear.

4.2 Overview of Environmental Retrofits

SO_2 Control Technology Options

Also known as scrubbers, flue gas desulfurization (FGD) equipment is installed to remove sulfur oxides from a plant's combustion gases before emission into the atmosphere.[64] The two commercially viable FGD technology options for coal-fired power plants contained in the EPA analysis are limestone forced oxidation (LSFO) scrubbers and lime spray dryers (LSDs).[65] In addition to LSFO and LSD technology options, dry sorbent injection (DSI) retrofits are also available to satisfy acid gases requirements under MATS.

NO_X Control Technology Options

NO_X reduction technologies can be categorized as either combustion or post-combustion controls. During the combustion process, combustion controls regulate temperature and fuel-air mixing, and consequently reduce NO_X emissions. Typical combustion controls include low NO_X burners (with or without overfire air), and low NO_X coal-and-air nozzles with close-coupled overfire air and/or separated overfire air.[66] At the downstream of the combustion process, post-combustion controls remove NO_X emissions from the flue gas. For existing coal units, selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) are two effective options to comply with standards under MATS and CAIR. An SCR system injects ammonia (NH3) vapor into the flue gas stream where NO_X is reduced to nitrogen and water by passing over a catalyst bed consisting of titanium, vanadium oxides, molybdenum, and/or tungsten. The SNCR system simply operates without the catalyst bed. The SCR achieves greater reduction efficiency at a higher cost. Despite the higher capital cost, for

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[64] EIA Glossary. http://www.eia.gov/tools/glossary/index.cfm?id=F.

[65] LSFO is a wet scrubber, and polluted gas stream is typically brought into contact with limestone or other liquid alkaline sorbent through a pool of the liquid slurry or by spraying the gas stream with the liquid; LSD is a semi-dry FGD technology using a spray dryer absorber, which helps bring the polluted gas stream into contact with the alkaline sorbent in a semi-dry state. http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/v410/Chapter5.pdf.

[66] http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/v410/Chapter5.pdf

large efficient units, SCR tends to be more cost effective than SNCR due to a lower $/ton removed cost.

Particulate Matter (PM) Control Technology Options

In order to control particulate matter (PM) emissions, units can install a combination of technology options: cold side electrostatic precipitator (ESPC), hot side electrostatic precipitator (ESPH), and fabric filter (FF). An ESP device removes particles from the polluted gas stream onto collector plates by charging the particles electrically to attract them to oppositely charged metal plates.[67] Fabric filters, also known as baghouses, remove PM from a polluted gas stream by sending the stream through a porous fabric; however, high temperature gases need to be cooled before passing through the filter.[68]

Mercury Control Technology Options

In order to meet Hg reduction requirements, units generally have two options: reductions of Hg can be a co-benefit derived from combinations of SO_2, NO_X, and particulate controls; or the installation of an activated carbon injection (ACI) system. ACI provides two alternative configurations: standard powdered activated carbon (SPAC) and modified powdered activated carbon (MPAC). When an ACI configuration is combined with an ESP system and fabric filter, it is known as the TOXECON™ configuration, patented by EPRI. The TOXECON™ configuration preserves fly ash sales without contamination due to the presence of ACI.[69]

Impact of EPA Regulations on Retrofits

EPA projects annual compliance costs under MATS are projected to $9.6 billion for 2015 when MATS goes into effect, and by 2030, the annual compliance cost is projected to be $7.4 billion,[70] with implementation resulting in significant deployment of pollution control retrofit options to reduce emissions of the following pollutants NO_X, SO_2, Hg, and PM.

According to EPA's National Electric Energy Data System (NEEDS), among the 1,099 coal units within the Eastern Interconnection, 34% of the units have installed either wet or dry scrubbers, while 56% of total coal capacities are equipped with either an SCR or SNCR. Almost all units have installed PM controls, and approximately 66% of all units covering 79% of total coal capacity have cold-side ESP. A total of 96 units have installed ACIs. The exhibits below display the number of coal units and total coal capacity by installed retrofit type.

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[67] http://www.epa.gov/apti/course422/ce6a1.html

[68] http://www.epa.gov/oar/oaqps/eog/course422/ce6a2.html

[69] http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/v410/Chapter5.pdf

[70] Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards. The numbers are calculated as 2007 dollars. EPA includes the final CSAPR in its estimates. http://www.epa.gov/ttnecas1/regdata/RIAs/matsriafinal.pdf

Exhibit 50: Number of Coal-fired Units with Operating Pollution Controls

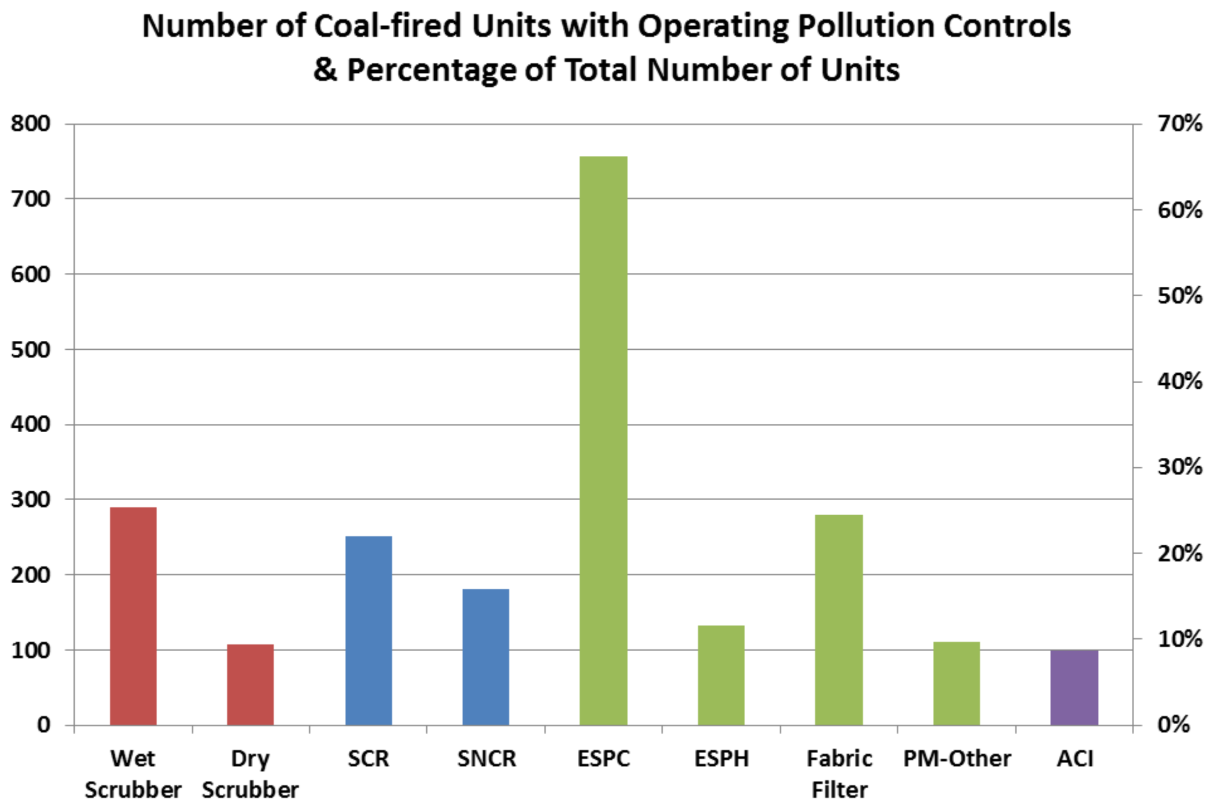
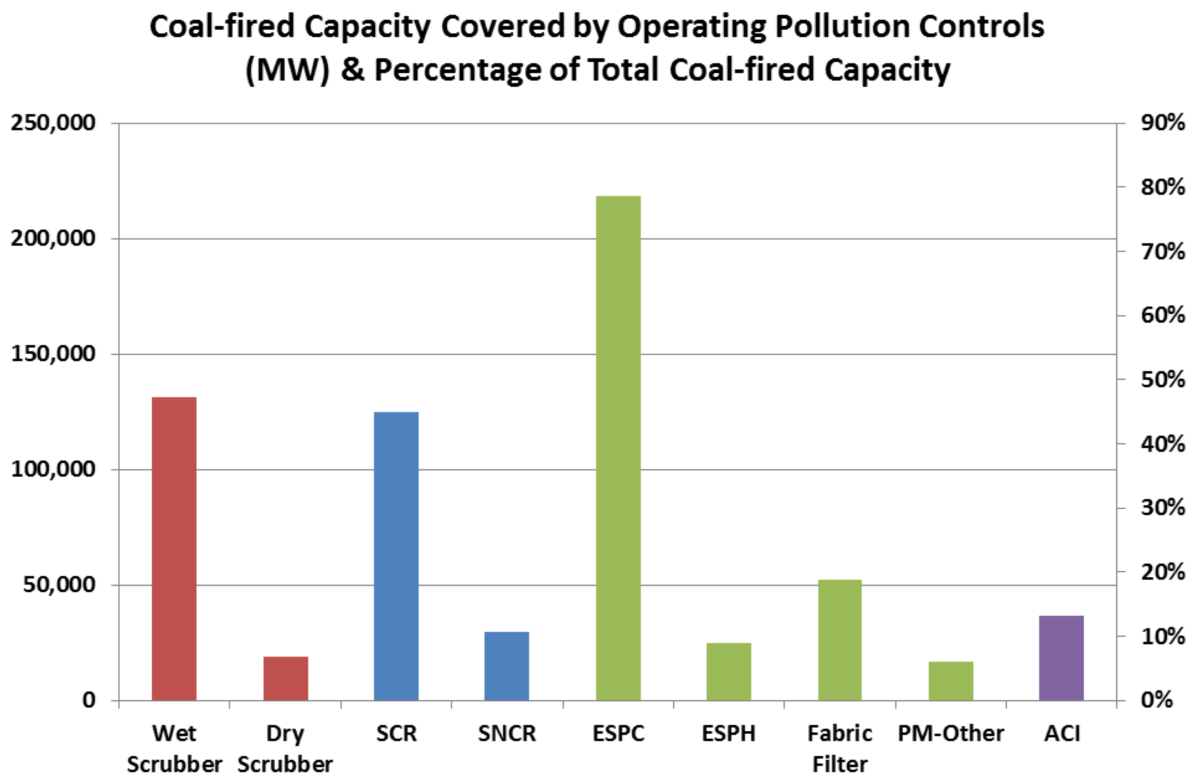


Exhibit 51: Operating Pollution Control Capacity on Coal-fired Capacity (MW)



4.3 Environmental Retrofits Cost and Performance Assumptions (2011$)

Retrofit Type	**Wet FGD (Limestone Forced Oxidation)**
Plant Characteristics	Heat rate: 10,000 Btu/kWh; Capacity: 300 MW
Pollutants Controlled	SO_2
Capital Cost ($/kW)	524
Capital Cost Components	Cost of foundations, buildings, electrical equipment, installation, minor waste water treatment, physical and chemical waste water treatment, and average retrofit difficulty were taken into consideration. Unit size, fuel source's sulfur content level, and heat rate greatly affect capital costs of retrofitting wet FGD.
VOM Cost ($/MWh)	2.52
VOM Cost Components	There are three components of VOM: costs for reagent usage, costs for waste generation, and make up water costs. Each cost component depends on the heat rate and fuel source's sulfur content.
FOM Cost ($/kW-yr)	8.86
FOM Cost Components	12 additional operators are required for a unit with a capacity of 500 MW or less, and 16 additional operators are required for a unit with a capacity of 500 MW and more.
Capacity & Heat Rate Penalty	Capacity and heat rate penalties reflect the additional power required to run the retrofits. When the heat rate is 10,000 Btu/MWh, the capacity penalty is -1.67% and heat rate penalty is 1.7%.
Percent Removal	Wet FGD is assumed to remove 98% of pollutants with a floor of 0.06 lb/MMBtu.
Capacity Applicability	The analysis is conducted on the basis that units have a capacity of 25 MW or more.

Retrofit Type	**Dry FGD (Lime Spray Dryer)**
Plant Characteristics	Heat rate: 10,000 Btu/kWh; Capacity: 300 MW
Pollutants Controlled	SO_2
Capital Cost ($/kW)	611
Capital Cost Components	Cost of foundations, buildings, electrical equipment, installation, minor waste water treatment, physical and chemical waste water treatment, and average retrofit difficulty were taken into consideration. Unit size, fuel source's sulfur content level, and heat rate greatly affect capital costs of retrofitting wet FGD.
VOM Cost ($/MWh)	1.96
VOM Cost Components	There are three components of VOM: costs for reagent usage, costs for waste generation, and make up water costs. Each cost component depends on the heat rate and fuel source's sulfur content.
FOM Cost ($/kW-yr)	11.52
FOM Cost Components	Eight additional operators are required.
Capacity & Heat Rate Penalty	Capacity and heat rate penalties reflect the additional power required to run the retrofits. When the heat rate is 10,000 Btu/MWh, the capacity penalty is -1.32% and heat rate penalty is 1.33%.
Percent Removal	Dry FGD is assumed to remove 93% of pollutants with a floor of 0.065 lb/MMBtu.
Capacity Applicability	The analysis is conducted on the basis that units have a capacity of 25 MW or more.

Retrofit Type	**Selective Catalytic Reduction (SCR)**
Plant Characteristics	Heat rate: 10,000 Btu/kWh; Capacity: 300 MW
Pollutants Controlled	NO_X
Capital Cost ($/kW)	205.96
Capital Cost Components	Cost of foundations, buildings, electrical equipment, installation, and average retrofit difficulty were taken into consideration. Unit size, coal rank, and heat rate greatly affect the governing costs.
VOM Cost ($/MWh)	1.32
VOM Cost Components	There are three components of VOM: costs for reagent usage, costs of catalyst replacement and disposal, and cost of required steam. Reagent usage and catalyst replacement and disposal costs are predominant. NO_X rates, heat rates, and coal rank greatly affect each cost component.
FOM Cost ($/kW-yr)	0.85
FOM Cost Components	Fixed operating cost is based on the assumption that one additional operator will work half-time. Fixed maintenance cost is $193,585 (2007$) for units with a capacity of 500 MW or less, and $290,377 (2007$) for units with a capacity of 500 MW or more. No FOM for administrating SCR is assumed in this case.
Capacity & Heat Rate Penalty	Capacity and heat rate penalties reflect the additional power required to run the retrofits. When the heat rate is 10,000 Btu/MWh, the capacity penalty is -0.56% and heat rate penalty is 0.56%.
Percent Removal	SCR is assumed to remove 90% of pollutants with a floor of 0.06 lb/MMBtu.
Capacity Applicability	The analysis is conducted on the basis that units have a capacity of 25 MW or more.

Retrofit Type	**Selective Non-Catalytic Reduction (SNCR) for Fluidized Bed Coal**
Plant Characteristics	Heat rate: 10,000 Btu/kWh; Capacity: 300 MW
Pollutants Controlled	NO_X
Capital Cost ($/kW)	20
Capital Cost Components	Cost of foundations, buildings, electrical equipment, installation, and average retrofit difficulty were taken into consideration. Unit size, coal rank, and heat rate greatly affect the governing costs.
VOM Cost ($/MWh)	1.05
VOM Cost Components	There are two components of VOM: costs for reagent usage and costs of dilution water. Reagent usage is predominant, while the cost of dilution water is at times near zero. NO_X rates, heat rates, and coal rank greatly affect each cost component. Capacity and heat rate penalty is minimal with SNCR.
FOM Cost ($/kW-yr)	0.43
FOM Cost Components	Fixed operating cost is based on the assumption that one additional operator will work half-time. No FOM for administrating SCR is assumed in this case.
Capacity & Heat Rate Penalty	Capacity and heat rate penalties reflect the additional power required to run the retrofits. When the heat rate is 10,000 Btu/MWh, the capacity penalty is -0.05% and heat rate penalty is 0.05%.
Percent Removal	SNCR for fluidized bed coal is assumed to remove 50% of pollutants.
Capacity Applicability	The analysis is conducted on the basis that units have a capacity of 25 MW or more.

Retrofit Type	**Selective Non-Catalytic Reduction (SNCR) for Pulverized Coal**
Plant Characteristics	Heat rate: 10,000 Btu/kWh; Capacity: 100 MW
Pollutants Controlled	NO_X
Capital Cost ($/kW)	50
Capital Cost Components	Cost of foundations, buildings, electrical equipment, installation, and average retrofit difficulty were taken into consideration. Unit size, coal rank, and heat rate greatly affect the governing costs.
VOM Cost ($/MWh)	1.05
VOM Cost Components	There are two components of VOM: costs for reagent usage and costs of dilution water. Reagent usage is predominant, while the cost of dilution water is at times near zero. NO_X rates, heat rates, and coal rank greatly affect each cost component. Capacity and heat rate penalty is minimal for SNCR.
FOM Cost ($/kW-yr)	1.07
FOM Cost Components	Fixed operating cost is based on the assumption that one additional operator will work half-time. No FOM for administrating SCR is assumed in this case.
Capacity & Heat Rate Penalty	Capacity and heat rate penalties reflect the additional power required to run the retrofits. When the heat rate is 10,000 Btu/MWh, the capacity penalty is -0.05% and heat rate penalty is 0.05%.
Percent Removal	SNCR for fluidized bed coal is assumed to remove 35% of pollutants.
Capacity Applicability	The analysis is conducted on the basis that units have a capacity of 25 MW or more.

Retrofit Type	**Activated Carbon Injection – MPAC**
Plant Characteristics	Capacity: 300 MW
Pollutants Controlled	Hg
Capital Cost ($/kW)	2.13 (with FF); 6.4 (with CESP)
Capital Cost Components	Cost of foundations, buildings, electrical equipment, installation, and average retrofit difficulty were taken into consideration. If an additional FF is required with ACI, capital costs also include duct work, foundations, structural steel, induced draft fan modifications or new booster fans, and electrical modifications.
VOM Cost ($/MWh)	0.18 (with FF); 0.65 (with CESP)
VOM Cost Components	There are two components of VOM: costs for reagent usage and unit costs; waste production and disposal costs. When a fabric filter exists, the cost of filter bag and cage replacement is also included in the VOM cost calculation. It is assumed that the A/C ratio is 6.0, and the bag and cage replacement takes place every three and nine years respectively.
FOM Cost ($/kW-yr)	0.05 (with FF); 0.11 (with CESP)
FOM Cost Components	Fixed operating cost is based on the assumption that one additional operator is required. Fixed maintenance cost is a direct function of capital costs, and fixed administrative cost is a function of fixed operating and fixed maintenance costs.
Capacity & Heat Rate Penalty	Capacity and heat rate penalties reflect the additional power required to run the retrofits. Capacity penalty is -0.43% and the heat rate penalty is 0.43%.
Percent Removal	ACI is expected to achieve 90% removal rate.
Capacity Applicability	The analysis is conducted on the basis that units have a capacity of 25 MW or more.

Retrofit Type	**Activated Carbon Injection – SPAC**
Plant Characteristics	Capacity: 300 MW
Pollutants Controlled	Hg
Capital Cost ($/kW)	4.27 (with existing FF); 22 (with existing ESP); 216 (with existing ESP and new FF i.e. Toxecon configuration)
Capital Cost Components	Cost of foundations, buildings, electrical equipment, installation, and average retrofit difficulty were taken into consideration. If an additional FF is required with ACI, capital costs also include duct work, foundations, structural steel, induced draft fan modifications or new booster fans, and electrical modifications.
VOM Cost ($/MWh)	0.25 (with existing FF); 2.63 (with existing ESP); 2.79 (with existing ESP and new FF i.e. Toxecon configuration)
VOM Cost Components	There are two components of VOM: costs for reagent usage and unit costs; waste production and disposal costs. When a fabric filter exists, the cost of filter bag and cage replacement is also included in the VOM cost calculation. It is assumed that the A/C ratio is 6.0, and the bag and cage replacement takes place every three and nine years respectively.
FOM Cost ($/kW-yr)	0.11 (with existing FF); 0.32 (with existing ESP); 2.67 (with existing ESP and new FF i.e. Toxecon configuration)
FOM Cost Components	Fixed operating cost is based on the assumption that one additional operator is required. Fixed maintenance cost is a direct function of capital costs, and fixed administrative cost is a function of fixed operating and fixed maintenance costs.
Capacity & Heat Rate Penalty	Capacity and heat rate penalties reflect the additional power required to run the retrofits. Capacity penalty is -0.43% and heat rate penalty is 0.43%.
Percent Removal	ACI is expected to achieve 90% removal rate.
Capacity Applicability	The analysis is conducted on the basis that units have a capacity of 25 MW or more.

Retrofit Type	**Dry Sorbent Injection (DSI)**
Plant Characteristics	Heat rate: 10,000 Btu/kWh; Capacity: 300 MW
Pollutants Controlled	SO_2
Capital Cost ($/kW)	61 (with FF); 70 (with ESP)
Capital Cost Components	Cost of foundations, buildings, electrical equipment, installation, and average retrofit difficulty were taken into consideration. Sorbent feed rate and fly ash waste handling costs are dominant costs, while plant size and coal rank are secondary variables.
VOM Cost ($/MWh)	7.17 (with FF); 13.31(with ESP)
VOM Cost Components	There are two components of VOM: costs for sorbent usage and waste production and disposal costs.
FOM Cost ($/kW-yr)	0.95 (with FF); 1.02 (with ESP)
FOM Cost Components	Fixed operating cost is based on the assumption that two additional operators will be required. Fixed maintenance cost is a direct function of capital costs, and fixed administrative cost is a function of fixed operating and maintenance costs.
Capacity & Heat Rate Penalty	Capacity and heat rate penalties reflect the additional power required to run the retrofits. When the heat rate is 10,000 Btu/MWh, with a fabric filter the capacity penalty is -0.71% and heat rate penalty is 0.72%; with ESP, the capacity penalty is -1.20%, and heat rate penalty is 1.22%.
Percent Removal	DSI is assumed to remove 70% of pollutants with fabric filter, and 50% with ESP.
Capacity Applicability	The analysis is conducted on the basis that units have a capacity of 25 MW or more.

4.4 Environmental Retrofits Levelized Cost Assumptions

With capital costs, variable operating and maintenance costs, and fixed operating and maintenance costs available from EPA's IPM analyses, ICF calculated the levelized cost in 2016 of various combinations of retrofit based on a number of assumptions. By 2016, all of the regulations are expected to be in place. All retrofits are assumed to be installed at pulverized coal plants operating at a capacity factor of 85%. levelized costs of retrofits were calculated for coal plant capacities of 100 MW, 300 MW, 500 MW, 700 MW, and 1,000 MW.

For the levelized cost calculations, ICF utilized the capital charge rates the EIA calculated as part of its Annual Energy Outlook 2012, less the 3% adder the EIA applied to the cost of debt and equity to reflect the risks of future carbon regulation, The capital charge rate used for pulverized coal plants without carbon capture and sequestration was 11.1%.

The components of the levelized cost in 2016 presented below are capital, VOM, FOM, and fuel costs. Fuel costs are calculated from delivered coal prices over the EIA's 2015 to 2034 time horizon, and only the incremental increase in fuel consumption is considered in the calculation of retrofits levelized costs. ICF levelized each cost component using a weighted average cost of capital of 6.15%, a figure that EPA applies across all retrofit technologies.

Exhibit 52: Levelized Costs in 2016 of Environmental Retrofits (2011$/MWh)

	Total Fixed Costs	Variable O&M	Fuel Costs	Total Levelized Costs
MPAC + FF	0.04	0.18	0.01	0.33
MPAC + CESP	0.11	0.65	0.11	0.87
SPAC + FF	0.08	0.25	0.11	0.44
SPAC + ESP	0.38	2.63	0.11	3.11
SPAC + ESP + Toxecon	3.57	2.79	0.11	6.47
FGD (Dry)	10.66	1.96	0.44	13.07
FGD (Wet)	9.00	2.52	0.35	11.87
SCR	3.18	1.32	0.15	4.65
SNCR (FBC)	0.36	1.05	0.01	1.42
SNCR (Non-FBC)	0.89	1.05	0.01	1.95
DSI + FF	1.03	7.17	0.19	8.39
DSI + ESP	1.19	13.31	0.32	14.81

The exhibits below illustrate the breakdown of levelized costs for various categories of environmental retrofits:

Exhibit 53 represents the levelized cost of installing ACI while PM controls – ESP or fabric filter – already exist. However, in the case of Toxecon, installing a new fabric filter is required.[71]

Exhibit 53: Levelized Cost of Activated Carbon Injection Installation (2011$/WMh)

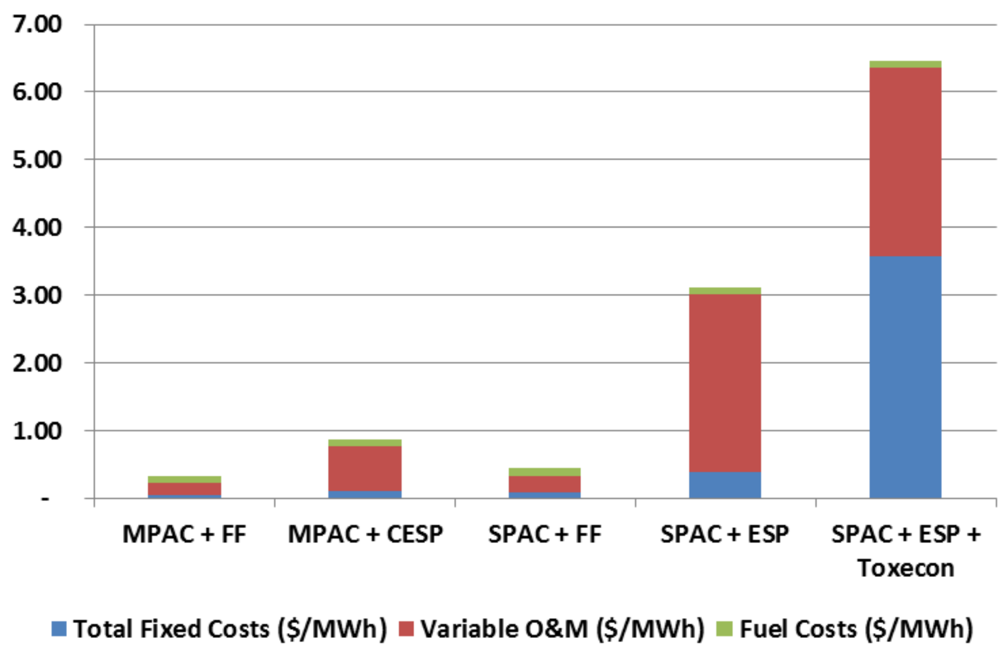
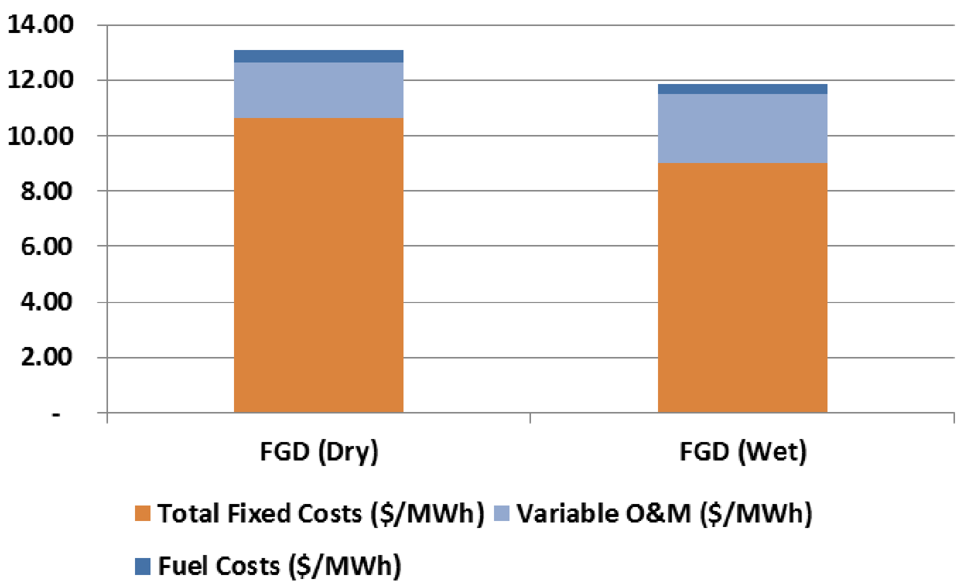


Exhibit 54: Levelized Cost of Scrubber Installation (2011$/WMh)



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[71] The Toxecon approach refers to the process where a small amount of bromine is chemically bonded to powdered carbon; then the powdered carbon is injected into the flue gas stream ahead of a pulsed-jet fabric filter, and downstream of both the pre-existing PM control devices and air pre-heater.

Exhibit 55: Levelized Cost of Post Combustion NO_X Controls Installation (2011$/WMh)

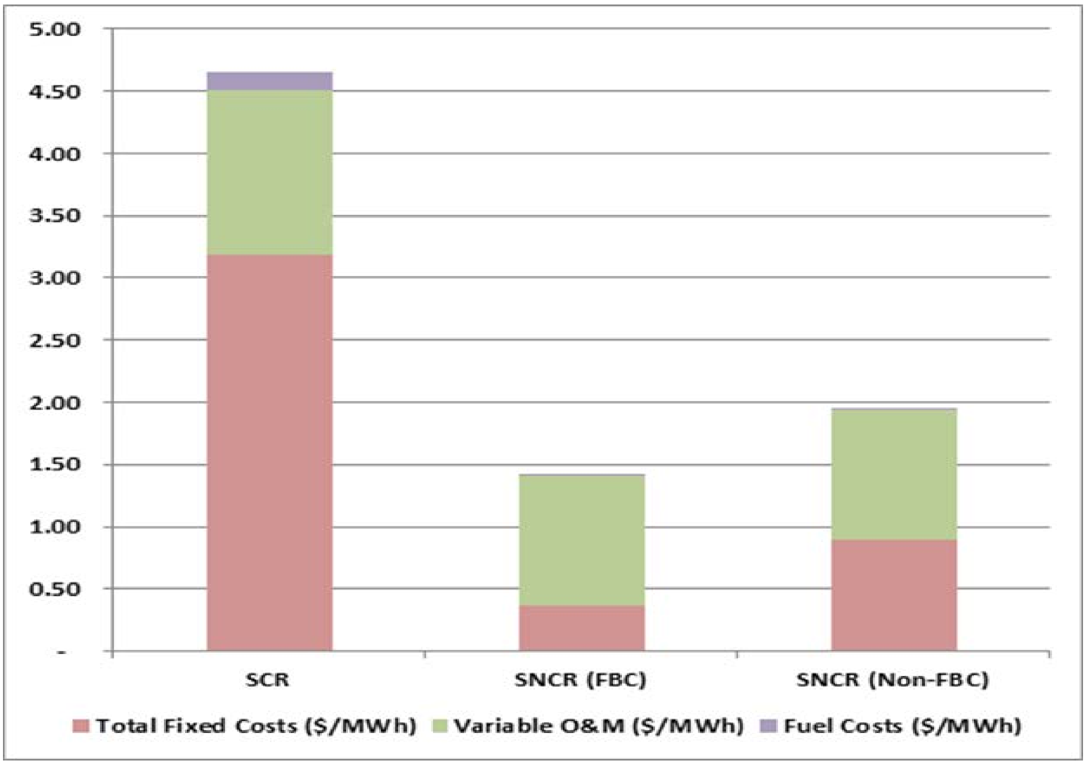
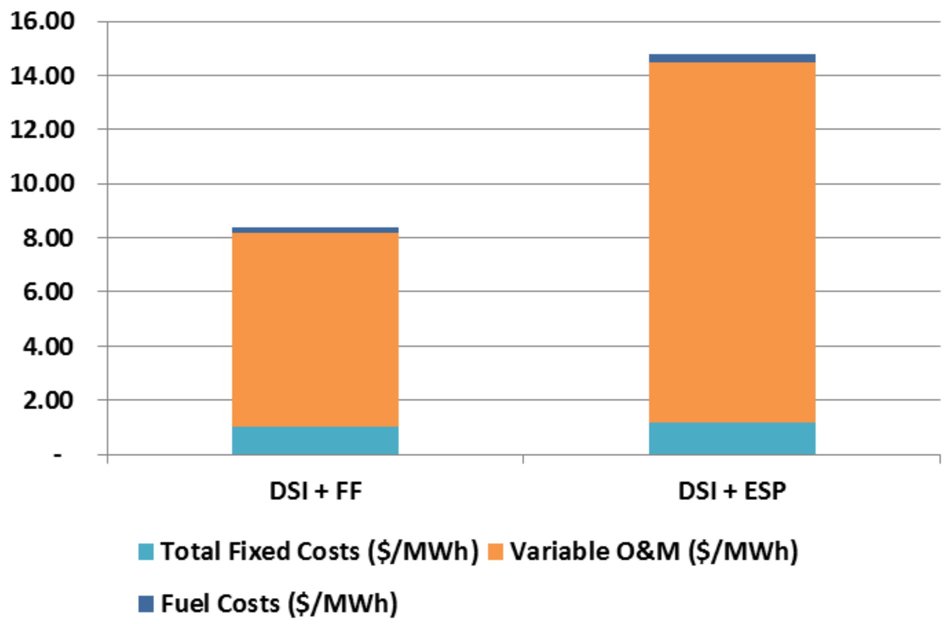


Exhibit 56 indicates levelized costs of installing DSI to units with existing PM controls – fabric filter or ESP.[72]

Exhibit 56: Levelized Cost of Dry Sorbent Injection Installation (2011$/WMh)



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[72] EPA, Documentation Supplement for EPA Base Case v4.10_PTox – Updates for Proposed Toxics Rule, Page 91.

4.5 Plant Life Extensions

For plant life extentsions, ICF relied on EPA's plant-life extension cost assumptions, which are based on FERC Form 1 data on annual capital expenditures over the past 10 to 15 years. Assuming plant-life extensions double the lifespan of the unit, combustion turbine and IC engine units require the lowest investment, while nuclear plants require the highest extension costs. Exhibit 57 below summarizes the basic assumption and cost data for plant-life extensions across each of the major power generation technologies.

Exhibit 57: Plant-life Extension Costs (2011$/kW)

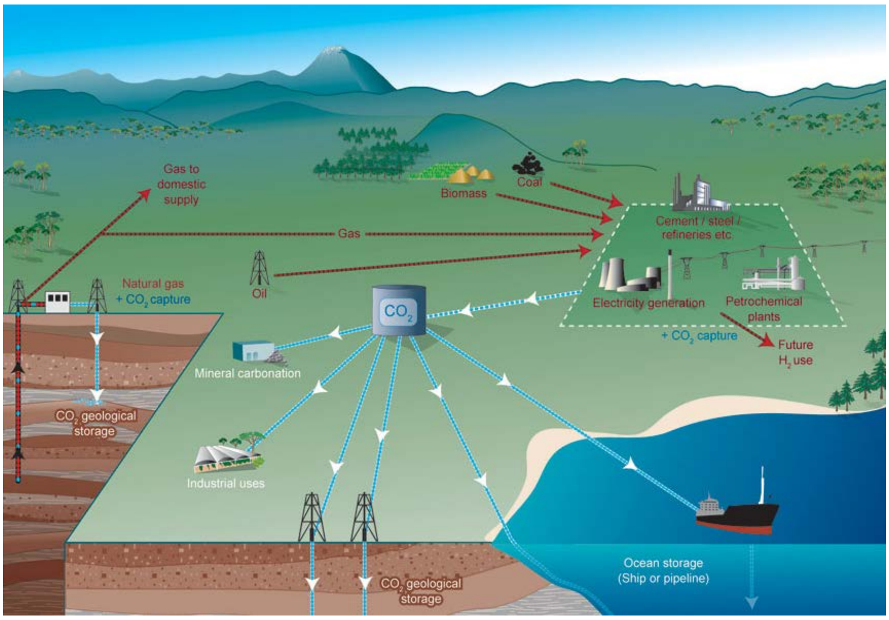
Plant Type	Lifespan without Life Extension	Life Extension Cost (% of New Unit Cost)	New Unit Cost (2011$/kW)	Life Extension Cost ($2011/kW)
Coal Steam	40	7.0	3114	218
Combined Cycle	30	9.3	1042	97
Combustion Turbine & IC	30	4.2	745	32
Oil/Gas Steam	40	3.4	2880	97
IGCC	40	7.4	3484	258
Nuclear	40	9.0	4931	444

Task 5: Carbon Capture and Sequestration (CCS)

5.1 Introduction to CCS

Carbon dioxide Capture and Storage (CCS) has the potential to significantly reduce carbon dioxide (CO_2) emissions associated with stationary sources such as natural gas and coal-fired power plants, and industrial processes. The CCS process consists of three phases: a) capture and compression of CO_2; b) transporting the captured CO_2 to a storage site; and c) injecting and safely storing the CO_2 in underground geological reservoirs. Exhibit 58 illustrates these components of CCS.

Exhibit 58: Illustration of CCS Components[73]



Source: IPCC, IPCC Special Report on Carbon Dioxide Capture and Storage

Coal-fired power plants remain the largest contributor to US greenhouse gas emissions, while emissions from coal-fired power plants comprise 40% of the global emissions from the consumption of energy.[74] The adoption of CCS technology by both the existing coal fleet and by planned coal-fired builds therefore has the potential to significantly reduce overall CO_2 emissions. CCS allows for meeting emission reduction targets while continuing to rely on coal-fired generation.

In 2010, the EIA conducted a study to estimate the cost of complying with President Obama's stated emission reduction goals of a reduction of 17% by 2020 and 83% by 2050

[73] IPCC, 2005, "IPCC Special Report on Carbon Dioxide Capture and Storage," by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

[74] CCS Task Force, 2010, Report of the Interagency Task Force on Carbon Capture and Storage, Washington, D.C., http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.

from 2005 levels.[75] In the base case, the projected allowance price in 2020 was \$31/tCO_2[76] equivalent, while in the absence of international offsets, prices in 2020 rose to \$52/tCO_2 equivalent. Moreover, in the case where international offsets are unavailable, nuclear and dedicated biomass electricity are unavailable beyond business-as-usual levels and CCS deployments were limited, prices rise to \$89/tCO_2 equivalent. Hence, the availability of CCS provides a significant cushion to allowance prices, and therefore the cost of attaining emissions targets.

As noted in Task 1, the Eastern Interconnection is home to some 269 GW of coal-fired capacity, which comprises around 84% of the nation's total coal capacity, and coal generation has frequently accounted for over 60% of the generation mix over the past 30 years in the EI. By contrast, at the national level, coal has comprised roughly 50-55% of total generation over the past 30 years, and made up 45% of total generation in 2010.

The preponderance of coal-fired generation in the EI means that CCS can have an especially large impact in reducing CO_2 emissions in the region, and will likely play a crucial role in helping to comply with future emission reduction targets in as cost-effective a manner as possible. Furthermore, as noted in Task 2, the introduction of New Source Performance Standards for new power plants imply that coal fired plants need to include CCS (either right away or within a few years) to ensure that the plants meet the required emissions level.

This report, written by ICF and Howard Herzog of Massachusetts Institute of Technology (MIT), covers the technology and cost elements of all three aspects of CCS: capture, storage, and transport. It also presents an overview of legal and regulatory issues associated with CCS, including state-level legislation regarding CO_2 storage.

5.2 Capture Technology

5.2.1 Overview[77]

CCS from power plants requires producing a relatively pure, high pressure stream of CO_2. Pressurized, high purity CO_2 helps the economics of transport and is preferred at the final destination, whether the CO_2 is being used in commercial processes or simply being stored in geologic formations. The process of producing the CO_2 stream is referred to as CO_2 capture. It encompasses all operations that take place at the power plant site, including separation from the flue gases and compression to over 100 atm[78].

CO_2 capture from power plants or industrial boilers first gained attention as a possible economic source of CO_2 for use in enhanced oil recovery (EOR) operations. In EOR, CO_2 is injected into oil reservoirs to increase the mobility of the oil and, therefore, the productivity of the reservoir. EOR allows for extraction of significantly more oil than primary production.

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[75] Annual Energy Outlook 2010 with Projections to 2035, Energy Information Administration.

[76] tCO_2 = metric ton of CO_2

[77] The majority of this section is modified from material presented in Herzog, H. J., "An Introduction to CO2 Separation and Capture Technologies," MIT Energy Laboratory Working Paper (1999). http://sequestration.mit.edu/pdf/introduction_to_capture.pdf

[78] In general, we want to compress the CO_2 above its critical pressure of 72.9 atm. Once above the critical pressure, it is relatively inexpensive to raise the pressure further.

Several commercial CO_2 capture plants were constructed in the late 1970s and early 1980s in the US. When the price of oil dropped in the mid-1980s, CO_2 captured from power plants became too expensive for EOR operations, forcing the closure of these capture facilities. Today, EOR primarily relies on the relatively inexpensive CO_2 from natural sources, such as the Jackson Dome field. However, the North American Chemical Plant in Trona, CA, which has captured the CO_2 from the flue gas of a coal boiler for carbonation of brine since 1978, is still in operation today.

In the 1990s, three CO_2 capture facilities were built to take advantage of the economic incentives in the Public Utility Regulatory Policies Act (PURPA) of 1978 for "qualifying facilities". The captured CO_2 was sold into commercial markets (i.e., food-grade CO_2). These three facilities are:

a. Northeast Energy Associates, Bellingham, MA, natural gas-fired turbines, capacity of 350 tons per day CO_2, operated 1991-2005.

b. AES Shady Point, Poteau, OK, coal-fired fluidized bed, capacity of 200 tons per day CO_2, operating since 1991, CO_2 sold to Tyson's for freezing chickens.

c. AES Warrior Run, Cumberland, MD, coal-fired fluidized bed, capacity of 150 tons per day CO_2, operating since 1999.

Starting in about 1990, the development of CO_2 capture has been motivated by climate change concerns. The US, as well as other major industrial countries, has a major RD&D effort on CCS. Besides annual appropriations of about \$200 million, CCS received \$3.4 billion in stimulus money, primarily aimed at funding large-scale demonstration plants.

CO_2 capture processes are classified into three categories: post-combustion, oxy-combustion, and pre-combustion. All of the existing commercial CO_2 capture plants discussed above use post-combustion capture. In other words, they capture the CO_2 from the flue gas of the power plant, where the CO_2 concentration ranges from a few percent for gas turbine outlets to ~10-12% from coal boilers.

The major component of flue gas is nitrogen, which enters with the combustion air. If there were no nitrogen, CO_2 capture would be greatly simplified. This is the thinking behind oxy-combustion capture, where instead of air, the power plant is fed high purity oxygen produced by an air separation plant.

The strategy in pre-combustion capture is to remove the CO_2 before the introduction of combustion air. This is a good fit with integrated coal gasification combined cycle (IGCC) power plants. Coal is gasified to form a synthesis gas (syngas) of CO and H_2. The gas then undergoes the water-gas shift, where the CO is reacted with steam to form CO_2 and H_2. The CO_2 is then removed, with the hydrogen being sent to a gas turbine combined cycle. A similar process is available for natural gas, where the syngas is formed by steam reforming of methane.

Detailed descriptions of these three approaches to CO_2 capture are found in section 5.2.3.

5.2.2 Separation Technologies[79]

No matter which of these three approaches are used, separation technology (i.e., technology for removing CO_2 from a gas stream) is a key component in all these processes. These separation technologies fall into four main categories: absorption, adsorption, membrane separation, and cryogenic separation. These technologies are described in the next sections.

5.2.2.1 Absorption

In chemical absorption, flue gas is scrubbed by a solvent in a type of distillation column called an absorber, which is filled with packing that assures good contact between the solvent and the flue gas. The solvent chemically reacts with the CO_2, removing it from the flue gas. Once the solvent is "loaded" with CO_2, it is regenerated in a stripper where the CO_2 is driven off and the solvent recycled back to the absorber. The stripper operates at higher temperatures than the absorber, which helps reverse the chemical reaction to release the CO_2. Exhibit 59 shows a schematic of a typical chemical absorption process.

For CO_2 capture from power plants, monoethanolamine (MEA) is the most widely used solvent today. It is a weak base, so that it has good reactivity with the CO_2 (an acid) in the absorber, but is still relatively easy to regenerate in the stripper. Stronger bases like NaOH can absorb the CO_2, but cannot be regenerated by a simple temperature swing, resulting in much greater energy requirements for regeneration. This is a critical trade-off in chemical absorption: we want a strong enough attraction for CO_2 to have reasonable reaction rates in the absorber, but not so strong as to make regeneration too energy intensive.

Flue gas contains SO_2, which is even a stronger acid than CO_2. Therefore, SO_2 will form a strong bond with the chemical solvent. This makes it necessary to remove most of the SO_2 prior to the CO_2 capture unit. Small amounts of SO_2 will still enter the CO_2 absorber, so a reclaimer unit is added to the process (see Exhibit 59) to chemically regenerate the solvent that has reacted with the SO_2.

To reduce the energy requirements in using chemical absorption for post-combustion capture, a number of alternative solvents to MEA are being developed and tested. Most prominent of these include chilled ammonia (Alstom Power), sterically hindered amines (MHI), piperazine (University of Texas), and amino acids (Siemens).

Another type of absorption is termed physical absorption. Instead of a chemical bond forming between the solvent and the CO_2, the CO_2 is physically dissolved in the solvent, similar to carbonated beverages.

There is a linear relationship between the CO_2 partial pressure (i.e., total pressure times CO_2 concentration) in the gas and the amount of CO_2 that can be absorbed. In flue gas, the partial pressure of CO_2 is about 0.1 atm, which is too low for physical absorption. However, in an IGCC plant, the partial pressure of CO_2 in the shifted synthesis gas is about 16 atm (40

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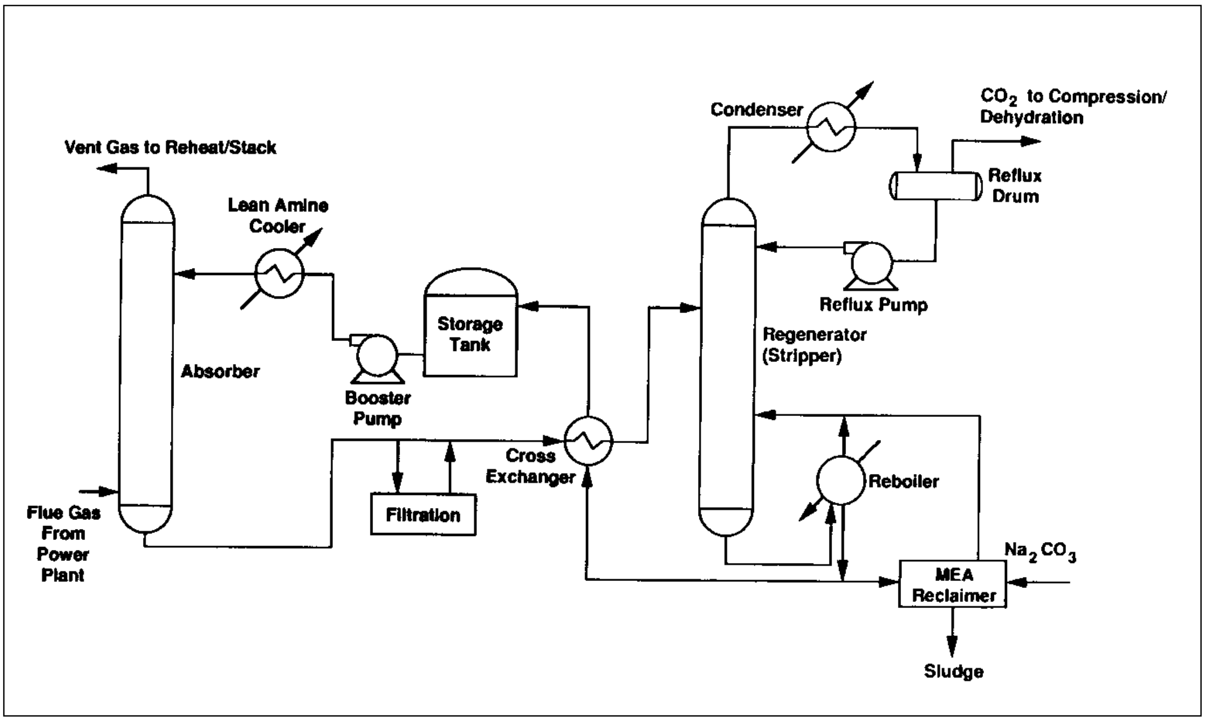
[79] More details on these topics can be found in: Herzog, H., J. Meldon, A. Hatton, "Advanced Post-Combustion CO_2 Capture," prepared for the Clean Air Task Force under a grant from the Doris Duke Foundation, April (2009). http://sequestration.mit.edu/pdf/Advanced_Post_Combustion_CO2_Capture.pdf

atm total pressure times 40% concentration), making it an ideal match for physical absorption.

Exhibit 59: Flow Diagram for the Amine Separation Process[80]



Source: DOE Order No. DE-AF22-96PC01257 (1997)

The front end of a physical absorption process is similar to chemical absorption, where the solvent and gas are contacted in an absorber. However, the physical sorbent can be regenerated by reducing its pressure (i.e., a pressure swing), which is much less energy intensive than the temperature swing regeneration of a chemical sorbent. The analogy with carbonated beverages is as follows: if you open a can of soda (i.e., lower the pressure), most of the CO_2 will eventually be released from the liquid (resulting in a flat soda).

In pre-combustion capture, the main two commercial solvents used for physical absorption are Selexol and Rectisol. Selexol is primarily dimethyl ether of polyethylene glycol and licensed from UOP. Rectisol is primarily methanol and licensed from Linde and Lurgi.

5.2.2.2 Adsorption

Adsorption is the process whereby molecules adhere to the surface of a solid material. Since adsorption is a surface-based process, good adsorbents need to have large surface areas per unit volume of sorbent. Some well-known traditional adsorbents include activated carbon and zeolites (i.e., microporous, aluminosilicate minerals). A relatively new class of adsorbent that has recently been developed is metal-organic frameworks (MOFs). As with absorption,

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[80] From Herzog, H. J., E. M. Drake, and E. E. Adams, "CO_2 Capture, Reuse and Storage Technologies for Mitigating Global Climate Change - A White Paper," DOE Order No. DE-AF22-96PC01257 (1997). http://sequestration.mit.edu/pdf/WhitePaper.pdf

adsorption has both physical and chemical sorbents and can be configured as either temperature swing or pressure swing, depending on the sorbent.

Adsorption processes generally utilize fixed beds (as opposed to distillation columns for absorption). These beds are simply vessels filled with sorbent. In capture mode, a fluid (i.e., a gas or liquid) flows through the bed. Once the sorbent reaches its capacity, the fluid flow is stopped and the bed must be regenerated by changing the bed temperature and/or pressure. A sweep gas, which helps "pump" the desorbed material, is commonly used to aid in regeneration.

An adsorption process will have multiple beds, some operating in capture mode, some in regeneration mode. The simplest set-up is two beds, one capturing and one regenerating. However, commercial adsorption processes can be very complex. A relatively new and very successful adsorption process has been used for hydrogen production. This process may have a dozen beds, each operating a little differently to yield both a high recovery rate as well as a high purity product.

A good sorbent should have high capacity for the material to be removed as well as good selectivity. For example, activated carbon has good capacity for CO_2, but relatively poor N_2/CO_2 selectivity. Zeolites have much better selectivity, but poorer capacity. In addition, water vapor will inhibit zeolite performance.

Physical adsorbents are not currently competitive with liquid solvents for CO_2 capture. To become more competitive, solid sorbents must be less sensitive to steam and offer substantially greater capacities and selectivities for CO_2. In addition, to regenerate solid sorbents in post-combustion capture, the adsorption bed would need to be put under vacuum to pump out the CO_2, which is very energy intensive and thus, costly.

5.2.2.3 Membrane Separation

As is true of membrane-based filtration and desalting of water, membrane-based gas separation is a well-established, mature technology. Many large plants are operating worldwide to recover oxygen and/or nitrogen from air, carbon dioxide from natural gas, and hydrogen from a variety of process streams.

Membranes, which generally consist of thin polymeric films, owe their selectivities to the relative rates at which chemical species permeate (i.e., flow) through the membrane. Differences in permeation rates are generally due to the relative sizes of the permeating molecules in porous membranes or their solubilities and/or diffusion coefficients (i.e., mobility) in dense membranes. Because permeation rates vary inversely with membrane thickness, membranes are made as thin as possible without compromising mechanical strength, which is frequently provided by non-selective, porous support layers.

Membrane permeation is generally pressure-driven – i.e., the feed gas is compressed and/or the permeate channel operates under vacuum and/or a sweep gas is employed. Due to the low partial pressure of CO_2 in the flue gas, this constitutes a major challenge for the membrane-based systems compared to liquid absorbents or solid adsorbents that are thermally regenerated (i.e., heated to strip the captured CO_2). It is generally uneconomic to pressurize flue gas, so the membrane systems would use vacuum on the permeate side, resulting in a requirement for large membrane surface areas.

Membrane processes have attracted considerably less attention for potential application to post-combustion carbon dioxide capture, than absorption and adsorption processes. This is attributed to the widely held view that membrane processes have high energy requirements and capital costs, with no economy of scale, and that available membranes are insufficiently selective. However, the US DOE is funding a major effort with Membrane Technology and Research (MTR) to develop a membrane system for post-combustion capture. The system has developed to a point to where pilot tests are planned at the National Carbon Capture Center in Wilsonville, AL.

In pre-combustion capture, membranes are being investigated to separate the H_2 from the CO_2 in the synthesis gas. Membranes are also being developed to produce oxygen. These are mixed metal oxide ceramic membranes, referred to as both ITM (Ionic Transport Membranes) or OTM (Oxygen Transport Membranes). These work at high temperatures (700^oC) and require an oxygen partial pressure driving force. There are at least four major development efforts, Air Products, StatoilHydro, Praxair, and Linde/BOC. The Air Products effort is at a 5 tpd scale, with plans to go to 150 tpd and then 2000 tpd.

In summary, membrane development is occurring in the laboratory and pilot plant for applications in post-combustion, pre-combustion, and oxy-combustion capture. However, no membrane process has yet been developed that can compete with the existing processes used today for CO_2 capture (absorption in pre- and post combustion, cryogenics for oxy-combustion).

5.2.2.4 Cryogenic Separation

Cryogenic separation works by cooling a vapor stream so that liquefaction occurs and components can be separated by phase (i.e., liquid-vapor separation). In order to get high purity products, cryogenic distillation may be required.

Cryogenic separation is the commercial process used today for large-scale air separation (i.e., production of O_2, N_2, Ar). These air separation units are required for oxygen-blown IGCC power plants, as well as oxy-combustion CO_2 capture. Turnkey plants are available from several commercial vendors.

It has been proposed to use cryogenic separation for post-combustion CO_2 capture, wherein power plant flue gas is cooled to separate the CO_2 as dry ice (CO_2 liquid does not exist at atmospheric pressure and pressurizing the flue gas is uneconomical). While technically feasible, this process does not appear to be economically attractive.

Cryogenic distillation has been proposed to separate out the few percent of non-compressible gases (e.g., N_2, O_2) in the CO_2 product in oxy-combustion processes. This would occur at high pressures, after the CO_2 has undergone significant compression.

5.2.2.5 Summary of Separation Technologies

In post-combustion capture, chemical absorption is the process of choice today. R&D is focused on improved absorption, as well as developing adsorbent processes. Additionally, lesser R&D efforts are underway for membrane-based separation. Cryogenic separation does not appear to be a good option for post-combustion capture.

For oxygen production, cryogenic separation is the standard process today for large-scale plants. There is a significant R&D effort underway to develop processes using ionic transport membranes.

For removing non-condensable gases from the CO_2 stream of an oxy-combustion plant, cryogenic distillation is proposed.

For pre-combustion capture, physical absorption is the process of choice today. Most R&D for alternative processes is focused on membrane separation.

5.2.2.6 CO_2 Compression and Dehydration

The last step in a CO_2 capture process is to compress the CO_2 so it can be transported to the location where it will be utilized or stored. Since CO_2 capture at power plants result in large volumes of CO_2 (e.g., about 10,000 tCO_2/day for a 500 MW_e coal-fired power plant), it will need to be transported by pipeline. Pipeline transport is a well-established technology, with nearly 4,000 miles of CO_2 pipelines existing today in the US to service the EOR industry. Key specifications for these pipelines are:

- For good operability, the pipeline operates in single phase flow. To assure single phase flow, the pipeline pressure at all times must be above the CO_2 critical pressure of 72.9 atm. Therefore, the CO_2 is generally compressed to 100-150 atm.
- To avoid corrosion, water must be removed to levels below 50 ppm. This allows the pipeline to be made of carbon steel and to avoid expensive alloys.

CO_2 is a highly compressible fluid. It enters the compressors as a gas with a density of less than 2 kg/m^3 and exits as a liquid-like fluid with a density about 800 kg/m^3 (liquid water is 1000 kg/m^3).

CO_2 compressors are available commercially. Not only do they pressurized the CO_2, they also separate out the water. The compressors are multi-stage, with cooling between stages. It is during these cooling stages that the bulk of the water condenses and is removed from the system. To reach the 50 ppm specification, a triethylene glycol absorber system can be placed between compression stages at about 35-40 atm.

5.2.3 CO_2 Capture in Power Plants

In this section, we will discuss the technical aspects of the three CO_2 capture pathways. The costs of these pathways will be discussed in section 5.2.4.

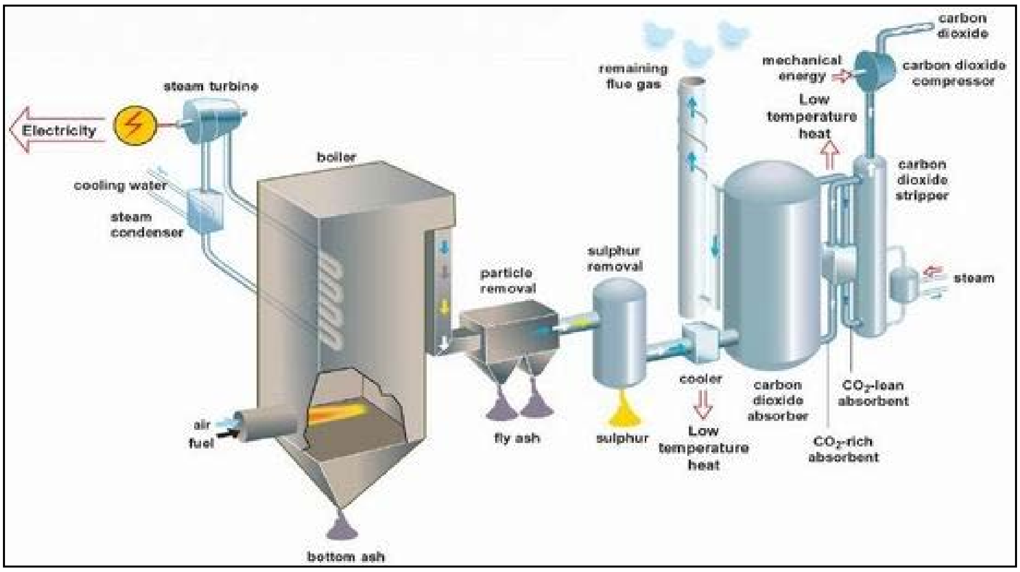
5.2.3.1 Post-Combustion Capture[81]

Post-combustion capture refers to the set of technologies that removes CO_2 from power plant flue gases. Because it operates on the plant's exhaust, it can be applied to any type of combustion power plant (e.g., coal, gas, biomass). The separation technology used today for post-combustion CO_2 capture on power plants is chemical absorption (see section 5.2.2.1). This process requires significant energy inputs in the form of both steam and electricity,

[81] For a more in-depth look at the technology, see Kothandaraman, A., "Carbon Dioxide Capture by Chemical Absorption: A Solvent Comparison Study," M.I.T. Ph.D. Dissertation, June (2010). http://sequestration.mit.edu/pdf/Anusha_Kothandaraman_thesis_June2010.pdf

which need to be supplied by the power plant (see Exhibit 60). A major R&D focus is to reduce the energy requirement through improved solvents and/or improved process design. While R&D projects are also investigating whether alternatives to chemical absorption (e.g., adsorption, membranes) can reduce energy needs and costs, it is likely that chemical absorption will be the technology of choice for the foreseeable future.

Exhibit 60: Post-Combustion CO_2 Capture Process (Absorption)[82]



Source: Vattenfall News & Reports

The power plant flue gas is characterized by its pressure, temperature, CO_2 concentration, criteria pollutant (i.e., particulates, SO_2, NO_x) levels, and O_2 level. Each of these has implications for CO_2 capture.

a. Pressure. Most power plant flue gas is at atmospheric pressure. This is one reason why chemical absorption is the process of choice. Higher pressure flue gases would make alternatives to chemical absorption more competitive.

b. Temperature. As described in section 5.2.1.1, the first step in a chemical absorption process is contacting the flue gas with the solvent in an absorber. For most of the solvents in use today, the absorber temperature is kept as cool as possible because the cooler the temperature, the more CO_2 the solvent can absorb. A typical operating temperature for an amine absorber is about 40°C. This means that the flue gas will need to be cooled with cooling water before entering the absorber.

c. CO_2 Concentration. The CO_2 concentration in the flue gas will be a function of the fuel used and the amount of excess air required. For coal plants, CO_2 concentrations range from 10-15%, for gas boilers 5-8%, and for gas turbines 3-5%. While chemical absorption can handle this whole

[82] Vattenfall. (2010). *Illustrations.* Retrieved from Vattenfall News & Reports website.

range, the more dilute the CO_2 concentration in the flue gas, the more expensive it is to remove a given amount of CO_2. Therefore, on a \$/tCO_2 basis, it will be more expensive to remove CO_2 from a gas power plant compared to a coal power plant.

d. ***Particulates.*** Particulates can cause the solvent to foam (analogous to the head that forms when pouring beer), which causes operability problems in the CO_2 removal process and, therefore, must be avoided. While not an issue for gas power plants, care must be taken when working with coal feeds. First, the power plant must have a good particulate removal system. Second, the CO_2 removal solvent needs to have adequate filtration (see Exhibit 59). Third, the solvent concentration may have to be kept low. Chemical solvents are aqueous (i.e., water-based) solutions. The early processes used 30% MEA solutions for gas plants, but only 20% for coal plants due to concerns about foaming. Today, efforts are being made to increase the solvent concentration, since this leads to reduced costs, so good particulate control becomes even more important.

e. ***SO_2 and NO_x.*** These acid gases will react with the chemical solvents, in many cases forming heat stable salts (i.e., the solvent cannot be regenerated via temperature swing). SO_2 is the more worrisome component because it is such a strong acid. Therefore, this is primarily an issue for coal power plants. The strategy is to reduce SO_2 levels to as low as possible in the FGD system. Since some SO_2 will enter the CO_2 removal process, a reclaimer is used to chemically regenerate solvent that has reacted with the SO_2 (see Exhibit 59).

f. ***Oxygen.*** Gas turbine systems use significant excess oxygen, resulting in elevated oxygen levels in the flue gas. Since oxygen promotes solvent degradation and corrosion for most chemical solvents, additives are added to inhibit such degradation and corrosion.

The other two main components of the flue gas, nitrogen and water vapor, are not an issue. The nitrogen is an inert and does not impact the solvent. It simply is vented out the top of the absorber. The water is removed during the compression step (see section 5.2.2.6).

Chemical absorption systems operate by using a temperature swing. Using MEA as the example (see Exhibit 59), the solvent absorbs CO_2 at low temperatures (around 40^oC) and is regenerated at high temperatures (around 110^oC). Energy, in the form of steam, is needed to drive this process. The steam, which enters the CO_2 capture process in the reboiler of the stripper column, serves three purposes:

a. Approximately 50% of the steam is used to provide the energy needed to break the chemical bond formed between the CO_2 and the solvent;
b. The energy required to raise the temperature of the solvent is called sensible heat. About 25% of the steam goes toward sensible heat. A cross exchanger is used between the absorber and stripper to provide much of the sensible heat requirement (i.e., the cold, CO_2-rich solvent leaving the absorber is heated by the hot, CO_2-lean solvent exiting the

stripper). However, to provide an adequate driving force in the exchanger, some of the sensible heat must be provided by steam. Note that the more concentrated the solvents (i.e., less water content), the less sensible heat will be needed;

c. Another 25% of the steam is used to make “stripping steam”. Stripping steam acts as a carrier gas for the CO_2 being released by the solvent. The CO_2-rich solvent enters the top of the stripper, while the steam is generated at the bottom. They flow counter-currently. As the CO_2 is released from the solvent, it flows up the column with the stripping steam. The stripping steam also acts a diluent to the released CO_2, making it easier for the CO_2 to leave the solvent.

The steam is extracted from the power plant steam system and although it may be feasible to build a stand-alone steam generator, such standalone steam generation is very energy inefficient. The CO_2 capture process needs relatively low pressure steam (at 110^{o}C, the saturated steam pressure is 1.5 atm)[83]. Therefore, some sort of topping cycle is desirable to make efficient use of the energy. Cogenerated steam to power the CO_2 removal process is, thus, critical for cost-effective CO_2 capture. For 90% capture, well over half the steam flow will need to be extracted from the steam turbines, which will require major design changes to the steam turbines.

To illustrate the parasitic load imposed by post-combustion CO_2 capture using chemical solvents, an example from the MIT Future of Coal Study[84] will be used (see Exhibit 61). The example starts with a supercritical coal-fired power plant with a net thermal efficiency of 38.5% before capture. To capture 90% of the CO_2, there are three major components to the parasitic load:

a. Steam requirement for the stripper reboiler. The steam extraction results in lower electricity production and reduces the overall power output by 13%
b. Electrical demand to run the CO_2 compressors. This reduces overall power output by 9.1%.
c. Electrical fans to run pumps and blowers needed for CO_2 capture. This reduces overall power output by 1.8%.

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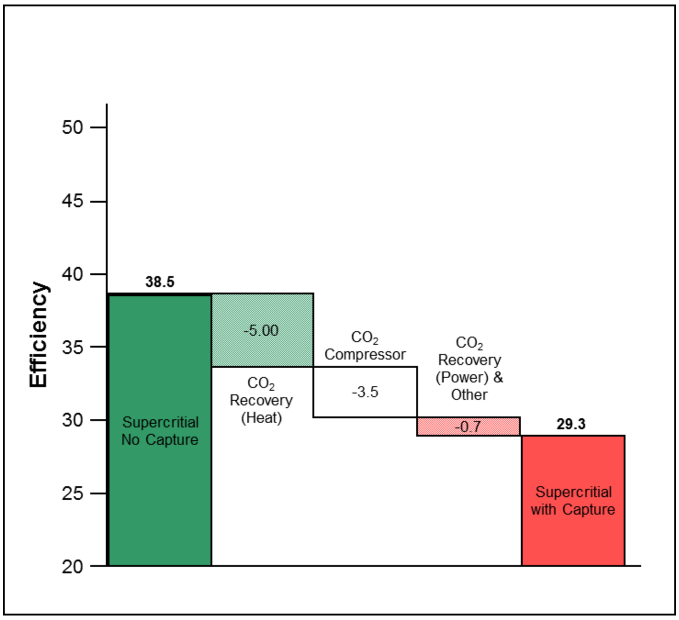
[83] In the stripper column, the pressure is correlated to the column temperature: as a first order approximation, it is the vapor pressure of water at that temperature. If the column could operate at higher pressures, then the CO_2 would exit the stripper at a higher pressure. This would lighten the load on the compression system, resulting in a lower demand for electricity to power the compressors. That savings would outweigh any additional costs of the stripper operating at higher temperatures. However, for MEA, going to higher pressures is not an option because the higher operating temperatures that would result would cause the MEA to decompose. However, new solvents under development may be able to operate under higher temperatures and pressures in the stripper.

[84] "The Future of Coal – Options for a Carbon Constrained World," MIT Interdisciplinary Report. March (2007). http://web.mit.edu/coal/

Overall, the net power output of the power plant is reduced by 24%, resulting in a net thermal efficiency of 29.3% with capture.

Exhibit 61: Parasitic Energy Requirement of Supercritical PC Units (Post-Combustion CO_2 Capture[85])



Source: MIT, The Future of Coal

This is a large parasitic load on the power plant. Therefore, one of the major goals of R&D on post-combustion capture is to reduce the parasitic load. For 90% capture from a coal-fired plant flue gas with CO_2 compression, the lowest theoretical achievable parasitic load is about 8%; however, a practical limit for the parasitic load may be about 16%, which is still a significant improvement from MEA processes available today.

Some of the alternative approaches to chemical absorption for post-combustion capture do not require any steam, but just use electricity as an energy input. For example, membrane systems have no steam requirement. So if these systems are comparable to chemical absorption in terms of overall energy use, they would have a major advantage of not requiring modifications to the power plant's steam system. In comparing post-combustion capture technologies, it is also important to consider the ease of integrating with the power plant and the impact on power plant flexibility and operability, in addition to capital cost and energy requirements.

5.2.3.2 Oxy-Combustion Capture[86]

Nitrogen is the major component of flue gas of fossil fuel power plants, and if there were no nitrogen, CO_2 capture from flue gas would be greatly simplified. In oxy-combustion capture,

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[85] *ibid*

[86] The majority of this section is modified from material presented in Herzog, H., "A Research Program for Promising Retrofit Technologies," prepared for the MIT Symposium on Retro-fitting of Coal-Fired Power Plants for Carbon Capture, March (2009). http://mitei.mit.edu/system/files/herzog-promising.pdf

the power plant combusts the fossil fuel using high purity oxygen (≥95% purity) instead of air, thereby eliminating most of the nitrogen. The oxygen is produced on-site in an air separation plant, which represents the largest cost component in the capture process.

Unlike post-combustion capture, where the CO_2 capture unit is separate from the power plant, in oxy-combustion capture the CO_2 capture equipment is integrated into the power plant. There are three distinct parts to oxy-combustion capture in power plants:

- The production of oxygen
- The modification of the boiler (gas turbines will be discussed later in this section) to use oxygen instead of air. This is necessary to prevent very high temperatures, as well as to meet the radiative and convective heat transfer characteristics of the boiler. This is accomplished by recycling part of the flue gas to the boiler.
- The clean-up of the flue gas of criteria pollutants (SO_2, NO_x, particulates, mercury) and non-condensibles (O_2, N_2, Ar) and compression of the CO_2.

A schematic of the oxy-combustion capture process is shown in Exhibit 62. The oxy-combustion process is capable of recovering all the CO_2 generated, but actual recovery rates are projected to be about 97%.

Oxy-combustion technology is commercially used in certain industries, such as glass, metals, cement, and waste treatment, [87] but there are no commercial oxy-combustion capture power plants operating today. However, there are several pilot plants around the world on the order of 30 MW_{th}. These include a boiler at Babcock & Wilcox's Clean Environment Development Facility (US) and a pilot plant at Vattenfall's Schwarze Pumpe plant (Germany) that includes a boiler, an oxygen plant, and a flue gas purification system. The 30 MW_e Callide-A Oxyfuel project just started up at the end of 2012 in Australia and consists of an oxygen plant and retrofitted boiler.

A major cost for oxyfuel combustion is the large quantity of high purity oxygen needed for combustion. The standard technology for large-scale oxygen production is cryogenic fractionation of air. The temperature involves liquefying air and separation via distillation. Energy for refrigeration is provided by compressing the air (and cooling upon expansion). The largest cryogenic air separation units (ASU) today are about 4000 tons per day (tpd). However, it is feasible to go to about 10,000 tpd, which would provide enough oxygen for a 500 MW coal-fired power plant. Above that level, multiple trains would be necessary.[88]

Designs of ASUs can vary significantly. For the oxy-combustion process, the design ASU specifications include relatively low oxygen purity (95-97%), low pressure (1.3-1.7 bar), low power consumption, and large size[89].

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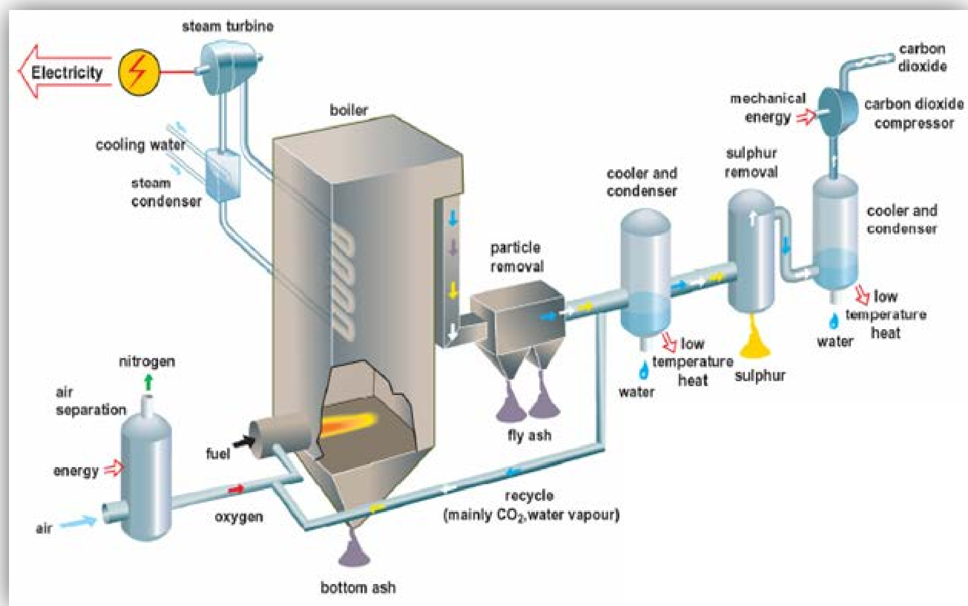
[87] Cieutat, D., I. Sanchez-Molinero, R. Tsiava, P. Recourt, N. Aimard and C. Prébendé, "The Oxy-combustion burner development for the CO_2 pilot at Lacq," *Energy Procedia*, **1**(1): 519-526 (2009)
[88] Allam R., "Improved oxygen production technologies," Energy Procedia, 1(1):461-470 (2009).
[89] McCauley K.J., H. Farzan, K.C. Alexander and D.K. McDonald, "Commercialization of

Exhibit 62: Oxyfuel Combustion CO_2 Capture Process[90]



Source: Vattenfall News & Reports

R&D has already started in adapting ASUs to oxy-combustion. Air Liquide[91] discuss design studies that show a 20% decrease in energy use over today's ASUs. They also suggest that another 10% savings is possible by integrating the ASU with the power cycle.

While the cryogenic process is today's state-of-the-art, the primary focus of R&D for the next generation of oxygen production is mixed metal oxide ceramic membranes, referred to as both ITM or OTM[92]. These work at high temperatures (700^{o}C) and require an oxygen partial pressure driving force. There are at least four major development efforts, Air Products, StatoilHydro, Praxair, and Linde/BOC. The Air Products effort is at a 5 tpd scale, with plans to go to 150 tpd and then 2000 tpd.

Boiler Modifications

Standard boilers for air-blown combustion can be easily modified for oxy-combustion. In the boiler, the temperature needs to be kept in a safe operating range and the heat transfer characteristics that the boiler was designed for must be maintained. This involves recycling a

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oxy-coal combustion: applying results of a large 30MWth pilot project," Energy Procedia, 1(1):439-446 (2009).

[90] Vattenfall, 2010. Illustrations. Retrieved from Vattenfall News & Reports website.

[91] Darde, A., R. Prabhakar, J-P. Tranierc and N. Perrin, "Air separation and flue gas compression and purification units for oxy-coal combustion systems," Energy Procedia, 1(1):966-971 (2009).

[92] Allam R., "Improved oxygen production technologies," Energy Procedia, 1(1):461-470 (2009).

significant portion of the flue gas to perform the function of the nitrogen which was removed in the air separation unit. Research questions include at which point in the process to take the recycle stream from (before or after certain flue gas clean-up steps, does it require cooling, etc.) and how to combine it with the oxygen.[93]

Another significant issue with the boiler retrofit is air enleakage. Most boilers are designed to run just below atmospheric pressure for safety considerations, which encourages air enleakage. Since the whole idea of oxy-combustion is to not feed air to the boiler, air enleakage needs to be minimized. Proper sealing of the boiler and associated equipment will help minimize air enleakage.

Another approach is to develop a purposely designed oxy-combustion boiler. This would maximize the increase in steam cycle efficiency, decrease boiler size, and could eliminate the need for flue gas recycle. Design of these boilers is a major R&D task. Another approach to boiler design that seems very compatible with oxy-combustion is the use of Circulating Fluidized Bed (CFB) technology.[94] Oxy-combustion can lead to small equipment sizes, control temperatures with circulating solids, and allow use of a wide range of low cost feedstocks.

Flue Gas Purification

The major impurities that need to be considered for removal from the flue gas are particulate matter (e.g., fly ash), criteria pollutants (e.g., SO_2, NO_x, mercury), non-condensible gases (e.g., Ar, N_2, O_2), and water. For retrofits, the CO_2 concentration in the flue gas exiting the boiler will generally be between 60-70%, with the above impurities making up the difference. The biggest reason for the range is the amount of air enleakage.

There are several strategies being pursued for flue gas purification. All the strategies have a few things in common. First, particulate matter must be removed using the same equipment in use on coal-fired power plants today. Some research may be needed on modifying the equipment for the new flue gas composition. The non-condensable gases and water will be removed during compression (water will be condensed, the non-condensable gases will be flashed).

This leaves the question about what to do with the criteria pollutants. There are at least three approaches:

- Do nothing. Let the SO_2 and NO_x remain with the CO_2 and co-sequester. This is the simplest and least expensive approach. However, it may cause complications for transport and storage (more regulatory and political as

[93] Tigges, K-D., F. Klauke, C. Bergins, K. Busekrus, J. Niesbach, M. Ehmann, C. Kuhr, F. Hoffmeister, B. Vollmer, T. Buddenberg, S. Wu and A. Kukoski, “Conversion of existing coal-fired power plants to oxyfuel combustion: Case study with experimental results and CFD simulations,” Energy Procedia, 1(1):549-556 (2009).
[94] Suraniti, S.L., N. Nsakala and S.L. Darling, “Alstom oxyfuel CFB boilers: A promising option for CO_2 capture,” Energy Procedia, 1(1):543-548 (2009).

opposed to technical). This approach also yields the highest recovery rates for CO_2;[95]

- Use the same equipment we do today to remove the NO_x (e.g., SCR - selective catalytic reduction) and SO_2 (FGD - flue gas desulfurization). Research will be needed to modify these approaches for the new flue gas composition;
- Eliminate the use of traditional SO_2 and NO_x control and simply remove them during compression by using a water wash. The SO_2 and NO_x will leave the system as sulfuric and nitric acids. Air Products has done initial tests of this approach and report that it looks very promising.[96]

In general, there is a trade-off between CO_2 purity and CO_2 recovery. This is because as impurities are removed, some CO_2 will leave with them. Another research area is to find ways to maintain high purity with high recovery. This includes using distillation (instead of a simple flash) to remove the non-condensable gases and using membranes to recover CO_2 from the impurity streams.

Energy Requirements

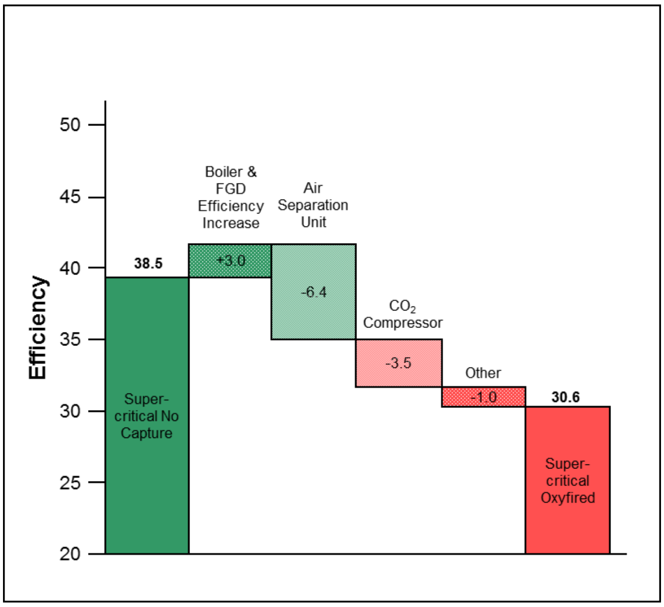
As with post-combustion capture, to illustrate the parasitic load imposed by oxy-combustion CO_2 capture an example from the MIT Future of Coal Study will be used (see Exhibit 63). The example starts with a supercritical coal-fired power plant with a net thermal efficiency of 38.5% before capture. To capture 90% of the CO_2, the major components to the parasitic load are:

a. Electric demand to power the air separation unit. This reduces overall power output by 16.6%;
b. Electrical demand to run the CO_2 compressors. This reduces overall power output by 9.1%;
c. Electrical fans to run pumps, blowers, etc. This reduces overall power output by 2.6%;
d. There is a potential efficiency gain in the boiler and FGD due to using oxygen instead of air of 7.8%.

Overall, the net power output of the power plant is reduced by about 21%, resulting in a net thermal efficiency of 30.6% with capture.

[95] Darde, A., R. Prabhakar, J-P. Tranierc and N. Perrin, "Air separation and flue gas compression and purification units for oxy-coal combustion systems," *Energy Procedia*, 1(1):966-971 (2009).
[96] White, V., L. Torrente-Murciano, D. Sturgeon and D. Chadwick, "Purification of Oxyfuel-Derived CO_2," Energy Procedia, 1(1):399-406 (2009).

Exhibit 63: Parasitic Energy Requirement for Supercritical PC Units (Oxy-Combustion CO_2 Capture)



Source: MIT, The Future of Coal

Oxy-combustion Turbines

There are two major efforts underway to develop an oxy-combustion turbine. The near-term goal for both of these efforts is to be able to sell CO_2 into the EOR market. Unlike the boiler approach, which tries to mimic an air-fired plant, the gas turbines under development are significantly different than the standard gas turbine used in the power industry today. Both of these efforts are planning to test prototype turbines by 2014.

One effort is led by Net Power[97], a start-up company funded by venture capital. Their turbine has an inlet pressure of 300 bar and an outlet pressure of 30 bar. About 97% of the turbine outlet is recompressed and recycled through the turbine. A critical part of the process is the heat integration between the air separation unit and the rest of the process. The turbine is under development by Toshiba.

The other effort is led by Siemens in collaboration with Clean Energy Systems[98]. The work has received a large grant from the Department of Energy's ARPA-E program. A standard turbine is being retrofit to use a novel combustor developed by Clean Energy Systems. This combustor is based on rocket technology.

5.2.3.3 Pre-Combustion Capture

Pre-combustion capture refers to CO_2 capture processes where the CO_2 is removed prior to the introduction of combustion air. Therefore, for coal feeds, it is applicable to integrated coal

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[97] Allam, et al., "Higher Efficiency and Lower Cost Electricity Generation from Fossil Fuels while Eliminating Atmospheric Emissions, Including Carbon Dioxide,"

[98] See http://www.siemens.com/innovation/apps/pof_microsite/_pof-spring-2010/_html_en/energy-research-in-the-us.html

gasification combined cycle (IGCC) power plants. Pre-combustion capture can be applied to natural gas, but this approach is not competitive with natural gas post-combustion capture. Therefore, most of this section will focus on the combination of IGCC plus capture, with some discussion of pre-combustion capture for natural gas at the end of this section.

IGCC power plants gasify the coal before combustion in a gas turbine. The coal is fed to a gasifier where it is partially oxidized to form a syngas containing primarily CO and H_2, along with smaller amounts of CH_4, CO_2, H_2O, H_2S, and other trace components. Most (but not all) commercial gasifiers use high purity oxygen (the others use air). Since this a partial oxidation, only about one-third the amount of oxygen required for oxy-combustion is required for gasification.

The gasifier operates at high pressures, typically at 40 atm, but it can go higher. Because the product syngas is at pressure, CO_2 capture costs can be greatly reduced compared to post-combustion capture. The only problem is that most of the carbon is in the form of CO, not CO_2 in the syngas. Reacting the CO with steam over a catalyst in a “water-gas shift” reactor will result in producing CO_2 and H_2. Now most of the carbon in the syngas is in the form of CO_2 and the energy is in the form of H_2. Since the syngas has a relatively high CO_2 concentration at high pressures, the CO_2 can be removed using physical absorption. This results in significant energy savings compared to chemical absorption in post-combustion capture. However, some of this savings is needed to offset the steam requirement in the water-gas shift reactor.

A schematic of the IGCC power plant with CO_2 capture is shown in Exhibit 64. Significant changes from an IGCC power plant without capture are:

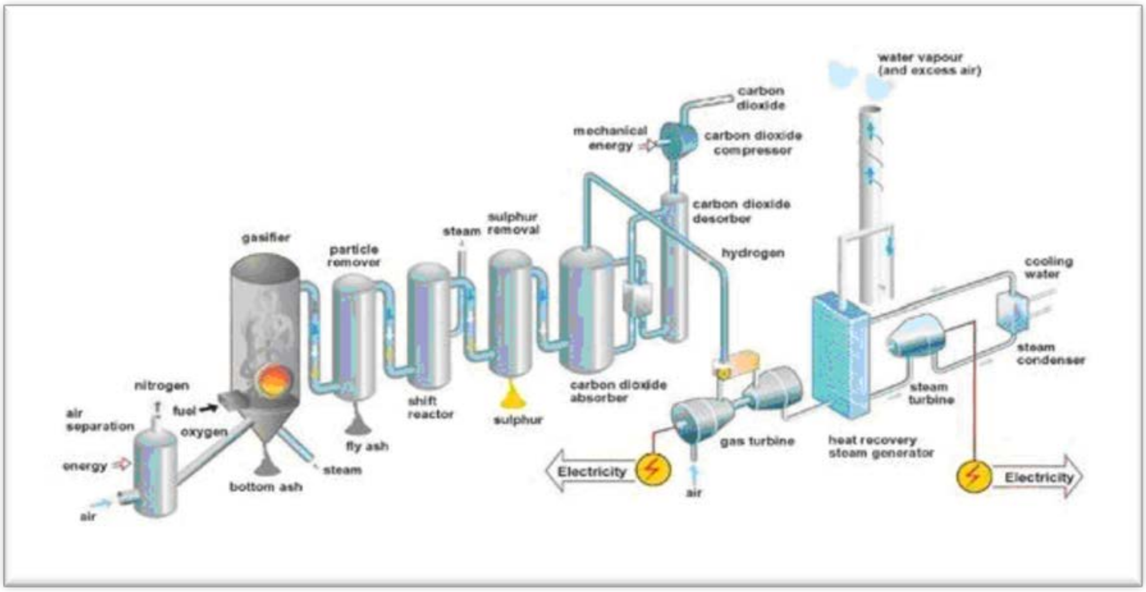
a. ***Gasifier.*** Gasifiers without CO_2 capture will generally have a radiant-quench system. This means that the exiting hot syngas will be used to raise steam as a means of heat recovery. The radiant quench system is a big heat exchanger, which has a large capital cost. The steam raised is sent to the steam turbine to produce power. If pre-combustion capture is added, then this steam will be needed for the shift reactors. The expensive radiant section can be eliminated and replaced by a much less expensive full-quench system, where water is injected directly into the syngas. The steam that is formed is carried with the syngas into the shift reactors.
b. ***Water-gas Shift Reactors.*** Some CO_2 is produced in the gasifier, but most of the carbon is in the form of CO. Without converting the CO to CO_2, no more than 25% of the total carbon can be captured. Adding a one-stage shift reactor allows for capture of up to 80% of the carbon, while a two-stage shift reactor allows over 90% capture.
c. ***CO_2 Capture Unit.*** CO_2 is removed from the syngas after the shift reactors. Because of the high pressure and high CO_2 concentration in the syngas, physical absorption (see Section 5.2.2.1) is the technology of choice. As detailed below, this leads to much smaller energy requirements compared to post-combustion capture. The physical absorption process is generally designed to also remove the H_2S (the CO_2 and H_2S come off as separate products). The CO_2 is absorbed at

high pressure and then released from the solvent by lowering the pressure. The desorption usually takes place at two or three pressures, so as to keep the CO_2 at the highest pressure possible entering the compression system.

CO_2 Compressors. A standard compression system is needed. The big difference in pre-combustion is that the CO_2 will enter at multiple inlet pressures. This has the benefit of reduced compression energy requirements compared to post-combustion capture.

d. ***Gas Turbine.*** Once the CO_2 is removed from the syngas, primarily hydrogen is left to feed the gas turbines. Since gas turbines cannot be fed pure hydrogen, it is diluted with nitrogen, a by-product of the ASU that produces the oxygen for the gasifier. A second consideration is that the turbines must be designed and tested for a hydrogen-rich syngas. While this is a straightforward technical issue, in practice the turbine manufactures will only make this modification on a limited number of their turbine models.

Exhibit 64: Pre-Combustion CO_2 Capture Process Using a Sour Shift[99]



Source: Vattenfall News & Reports

To illustrate the parasitic load imposed by pre-combustion CO_2 capture, once again an example from the MIT Future of Coal Study (ref) will be used (see Exhibit 65). The example starts with an IGCC coal-fired power plant with a net thermal efficiency of 38.4% before capture. To capture 90% of the CO_2, the major components to the parasitic load are:

a. Reduction in electrical production primarily due to the steam demand of the water-gas shift reaction. This reduces overall power output by 10.9%.

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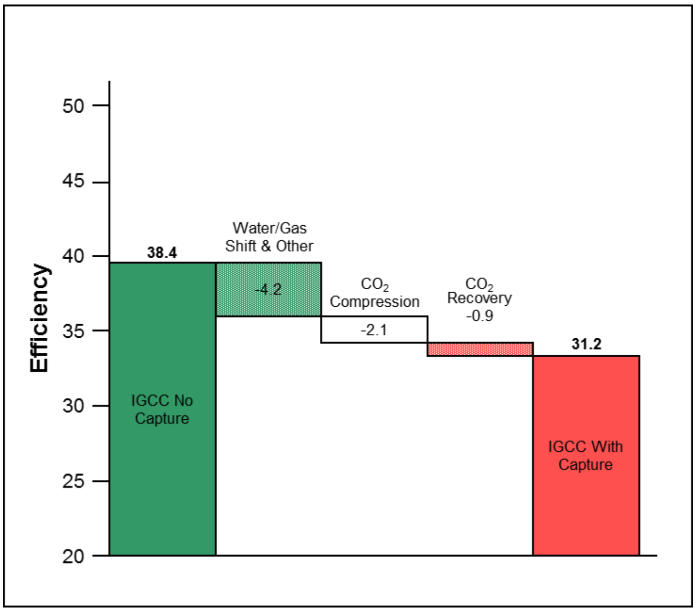
[99] Vattenfall, 2010. *Illustrations.* Retrieved from Vattenfall News & Reports website.

b. Electrical demand to run pumps, blowers, etc., needed for CO_2 removal by physical absorption. This reduces overall power output by 2.3%.
c. Electrical demand to run the CO_2 compressors. This reduces overall power output by 5.4%.

Overall, the net power output of the power plant is reduced by about 19%, resulting in a net thermal efficiency of 31.2% with capture.

Exhibit 65: Parasitic Energy Requirement for IGCC with Pre-Combustion CO_2 Capture



Source: MIT, The Future of Coal

The critical issues that need to be resolved for an IGCC power plant with pre-combustion capture to become competitive with a PC power plant with post-combustion capture are related more to the cost of an IGCC plant than to the cost of pre-combustion capture. Breaking down the total costs into two components (power plant cost + cost of capture), pre-combustion capture is significantly better than post-combustion. However, the cost of an IGCC power plant today is so much more than a PC power plant that it wipes out the savings in capture costs. The costs of the IGCC power plants must become more competitive with PC power plants for the pre-combustion capture pathway to be competitive for coal-fired power plants.

Because IGCC power plants are relatively expensive, there are only two operating plants in the US (both resulting from demonstration projects subsidized by the US DOE). In addition, an IGCC power plant (no capture) is under construction in Edwardsport, IN by Duke Energy using commercial (General Electric) technology. Southern Company is demonstrating a new IGCC technology (called the transport reactor) in Kemper County, MS, with assistance from the US DOE. It will capture about 50% of the CO_2 to sell for EOR. The PUC's of these respective states approved the projects, despite it meaning higher rates for the customers. These decisions were justified by the perceived longer-term strategic impact of these projects.

The syngas produced by the IGCC plants is an excellent feedstock to produce chemicals and fuels. Since these products may have more value-added, the concept of a "polygeneration" plant is being investigated. The Texas Clean Energy Project (Summit Energy), a recipient of CCS stimulus money, is developing a demonstration project based on an IGCC that will produce urea in addition to electricity and CO_2.

It is feasible to apply pre-combustion to natural gas-fired power plants. Instead of gasifying coal, the syngas is made by reforming the natural gas (e.g., reacting the gas with steam over a catalyst). This process is very common in the chemical industry, for example in the production of hydrogen. The Norwegian company Norsk Hydro (now part of Statoil) first proposed this process in the 1990s. The following decade, BP proposed this technique for the Peterhead demonstration project in the UK. Neither of these efforts proceeded beyond the planning stage.

Studies in the peer-reviewed literature show that pre-combustion capture of natural gas is *not* competitive with post-combustion capture[100].

5.2.3.4 Comparison of Capture Pathways

The advantages and disadvantages of the different capture pathways for coal-fired power plants are summarized in Exhibit 66. Post-combustion capture is the most compatible with the existing coal fleet, but imposes a significant energy penalty on those plants. Oxy-combustion capture may be somewhat less expensive, but we do not have enough experience to verify this claim. Pre-combustion capture allows for the least expensive capture, but the premium one must pay for an IGCC plant is too high today.

The MIT Future of Coal Study came to the following conclusion about these choices: *It is premature to select one coal conversion technology as the preferred route for cost-effective electricity generation combined with CCS.* Furthermore, due to variability in the market, such as in plant location and coal types, as well as uncertainty in technological progress, it is possible that all three of these pathways may be viable in a future low-carbon marketplace.

Exhibit 66: Comparison of Capture Pathways for Coal-Fired Power Plants

Capture Process	Advantages	Disadvantages
Post-Combustion	Compatible with existing infrastructure; retrofits; flexibility	Current methods have high energy penalties
Oxy-Combustion	Potentially less expensive than post-combustion; retrofits	Cost of oxygen; lack of experience
Pre-Combustion	Projected lowest incremental cost for capture	Slow progress of IGCC in power sector

5.2.4 Cost of Capture

[100] Bolland, O and H Undrum, "Removal of CO_2 from Gas Turbine Power Plants: Evaluation of Pre- and Postcombustion Methods," Eliasson, B.; Reimer, P.; Wokaum, A., eds. Proc. of the 4th Inter. Conf. on Greenhouse Gas Control Technologies, Oxford: Elsevier Science Ltd., pp. 125-130 (1999).

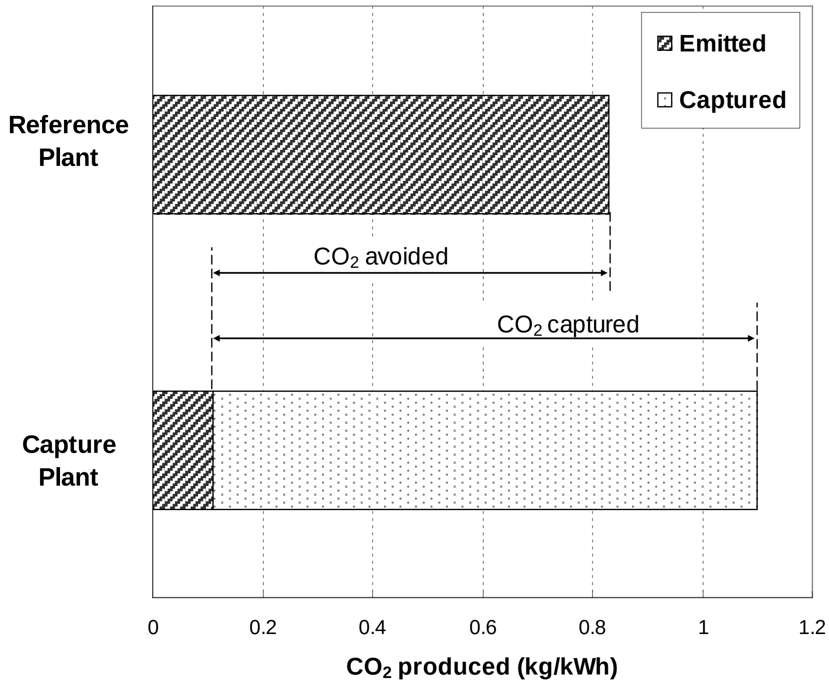
There are two major metrics to describe the cost of CO_2 capture, the incremental cost of electricity (COE) and the cost of CO_2 avoided (sometimes referred to as the mitigation cost). To calculate these costs, two levelized cost analyses are conducted: one for a power plant without CCS (termed the reference plant) and one for a power plant with CCS. The incremental COE is simply the difference in the COEs for the two cases. The cost of avoided CO_2 is calculated by dividing the incremental COE by the avoided CO_2 emissions (i.e., the reduction in CO_2 emissions per unit of electrical output). The avoided cost is an important metric because it is directly comparable to the permit price for a cap-and-trade system (or the amount of a carbon tax).

In doing the calculation, the results will change depending on the choice of reference plant. In many cases, the reference plant is simply the same type of power plant as the capture plant, just without capture. However, say one wishes to compare the cost of CO_2 capture between a pulverized coal plant with post-combustion capture and an IGCC plant with pre-combustion capture. To be able to make an apples-to-apples comparison, the same reference plant must be used in both cases. There is more discussion on this topic later in this section.

Sometimes costs may be reported as cost of CO_2 captured. Instead of using the avoided CO_2 emissions in the calculation described above, one simply uses the total amount of CO_2 captured (once again normalized per unit of electrical output). These are two very different numbers. If CO_2 is being captured to sell into commercial markets, the captured cost is appropriate. However, if CO_2 is being captured for climate purposes, then the avoided cost is the right metric. The difference between these two metrics is explained in more detail below.

Because of the parasitic energy requirement, the number of tons avoided is always less than the number captured. This is shown graphically in Exhibit 67. The top bar shows the amount of CO_2 emitted per kWh from a reference power plant without capture. The lower bar shows the amounts of CO_2 emitted and captured per kWh from the same power plant with 90% CO_2 capture (includes compression). Because of the parasitic energy requirement, more CO_2 is produced *per kWh* in the capture plant. The amount of CO_2 avoided is simply the difference in emissions between the reference plant and the plant with capture. Another way to look at this is that the avoided tons are the total tons captured minus the amount of CO_2 generated by the capture process. Because the amount avoided is always less than the amount captured, the \$/tCO_2 avoided is always greater than the \$/tCO_2 captured.

Exhibit 67: Graphical representation of avoided CO_2[101]



Source: Herzog, The Economics of CO_2 Separation and Capture

There are many costing studies in the literature. They can be classified into two types: detailed bottom-up engineering studies and synthesis studies (based on the detailed engineering studies). The engineering studies are a fairly expensive undertaking. Key organizations that put out these studies include EPRI, US Department of Energy (through the National Energy Technology Laboratory), and the IEAGHG R&D Programme. The results of engineering studies are not always easy to compare directly because they may use different design bases, different power plant and/or capture technologies, different economic assumptions, etc. The synthesis studies generally try to represent the results of the various engineering studies on a common basis. The results of one such study is presented below.

Finkenrath (2011)[102] examined costing studies from the following eight organizations (dates of the studies in parentheses):

- Carnegie Mellon University (2007, 2009, 2010)
- China-UK Near Zero Emissions Coal Initiative (2009)
- CO_2 Capture Project (2009)

[101] The avoided emissions are simply the difference between the actual emissions per kWh of the two plants. Note that due to the parasitic energy requirement (and its associated additional CO_2 production), the amount of emissions avoided is always less than the amount of CO_2 captured. Herzog, H. "The Economics of CO_2 Separation and Capture," Technology, vol 7, supplement 1, pp 13-23 (2000). http://sequestration.mit.edu/pdf/economics_in_technology.pdf

[102] Finkenrath, M, *Cost and Performance of Carbon Dioxide Capture from Power Generation*, Working Paper, International Energy Agency, Paris (2011).

- Electric Power Research Institute (2009)
- Global CCS Institute (2009)
- IEAGHG R&D Programme (2007, 2009)
- National Energy Technology Laboratory (2008, 2010)
- Massachusetts Institute of Technology (2007, 2009)

The results are shown in Exhibit 68. Note that these results include capture and compression, but not transport and storage. The key findings include:

- Considering uncertainties, no single technology outperforms the alternative routes for coal-fired power generation (this reinforces the conclusion of the MIT Future of Coal Study in Section 5.2.3.4).
- For near-term CO_2 capture from natural gas-fired power plants, post-combustion CO_2 capture appears most attractive
- Variability between and uncertainty of costs remains significant
- The relative increase of cost compared to a plant without CO_2 capture is often comparably stable across studies

The primary results in Exhibit 68 define the reference power plant as the same type of power plant used in the capture case. This makes the IGCC pre-combustion route appear to be the least expensive. However, this does not take into account the fact that an IGCC plant without capture is more expensive than a PC plant without capture. In order to make an apples-to-apples comparison, a PC plant without capture should be used as a reference plant for all the coal-fired cases. When this is done, all three options are similar, with average overnight costs of about \$3800/kW for coal-fired power generation regardless of capture route (+74%) and a mitigation cost of about \$55/tCO_2 cost of avoided (does not include transport and storage).

For NGCC power plants, the mitigation cost was \$80/tCO_2 avoided (vs. \$55 for coal) and the relative incremental cost of electricity was 33% (vs. about 60% for coal). This reflects two facts:

- The concentration of CO_2 in the flue gas from gas power plants is less than that in coal power plants, so the capture cost is more per unit of CO_2.
- There is about 50% less CO_2 to remove from a gas plant compared to a coal plant, so the impact on the incremental COE is less.

One final note, these studies were conducted before the extremely low gas prices in the US of the past couple of years. At these very low gas prices, it is possible for the avoided cost for gas plants to be less than that of coal plants.

Exhibit 68: Average cost and performance data by capture route for OECD countries

Fuel type	Coal			NG
Capture route	Post-combustion	Pre-combustion	Oxy-combustion	Post-combustion
Reference plant w/out capture	PC	IGCC (PC)	PC	NGCC
Overnight cost w/capture (USD/kW)	3808	3714	3959	1715
Relative overnight cost increase	75%	44% (71%)	74%	82%
LCOE w/capture (USD/MWh)	107	104	102	102
Relative LCOE increase	63%	39% (55%)	64%	33%
Cost of CO_2 avoided (USD/tCO_2)	58	43 (55)	52	80

Source: IEA, Cost and Performance of Carbon Dioxide Capture from Power Generation

Notes: Data cover only CO_2 capture and compression but not transportation and storage. The accuracy of feasibility study capital cost estimates is on average ±30%, hence for coal the variation in average overnight costs, LCOE and cost of CO_2 avoided between capture routes is within the uncertainty of the study. Underlying oxy-combustion data include some cases with CO_2 purities <97%. Overnight costs include owner's, EPC and contingency costs, but not IDC. A 15% contingency based on EPC cost is added for unforeseen technical or regulatory difficulties for CCS cases, compared to a 5% contingency applied for non-CCS cases. IDC is included in LCOE calculations. Fuel price assumptions differ between regions. Results in 2010 dollars.

5.2.5 CCS Ready Power Plants

The idea of a CCS Ready power plant has been investigated over the past several years by a number of groups, including MIT[103] and ICF[104]. This section highlights some of the key findings.

As shown in the previous sections of this report, designing a power plant optimized for CCS would have significant differences compared to the optimized design of a power plant without CCS. These differences go beyond just the extra equipment required for capture. For example, on an IPCC power plant, a no capture plant would have a radiant quench for the gasifier effluent, while a capture plant would have a full quench (see section 5.2.3.3). Another example is that the steam system design (including turbines) on a PC power plant is very different depending on whether CCS is included or not (see section 5.2.3.1). Therefore, being CCS Ready is not simply "plug and play", such as in the example of a cable-ready television.

The GCCSI has put together a definition of CCS-ready[105]:

> A CCS Ready facility is a large-scale industrial or power source of CO_2 which could and is intended to be retrofitted with CCS technology when the necessary regulatory and economic drivers are in place. The aim of building new facilities or modifying existing facilities to be CCS Ready is to reduce the risk of carbon emission lock-in or of being unable to fully utilise the facilities in the future without CCS (stranded assets). CCS Ready is not a CO_2 mitigation option, but a way to facilitate CO_2 mitigation in the future. CCS Ready ceases to be applicable in jurisdictions where the necessary drivers are already in place, or once they come in place.

The GCCSI also issued a list of essential requirements for a CCS Ready facility. They represent the minimum criteria that should be met before a facility can be considered CCS Ready. The project developer should:

- Carry out a site-specific study in sufficient engineering detail to ensure the facility is technically capable of being fully retrofitted for CO_2 capture, using one or more choices of technology which are proven or whose performance can be reliably estimated as being suitable.
- Demonstrate that retrofitted capture equipment can be connected to the existing equipment effectively and without an excessive outage period and

[103] Bohm, M.C., H.J. Herzog, J.E. Parsons and R.C. Sekar, "Capture-ready coal plants - Options, technologies and economics," International Journal of Greenhouse Gas Control, Vol 1, pages 113-120 (2007). http://sequestration.mit.edu/pdf/capture-ready_coal_plants-options_technologies.pdf

[104] ICF International (2010), Defining CCS Ready: An approach to an international definition, A report prepared for the Global CCS Institute
ICF International (2010), CCS Ready Policy: Considerations and recommended practices for Policy Makers. A report prepared for the Global CCS Institute

[105] http://www.globalccsinstitute.com/insights/authors/christophershort/2010/11/03/definition-ccs-ready

that there will be sufficient space available to construct and safely operate additional capture and compression facilities.

- Identify realistic pipeline or other route(s) to storage of CO_2.
- Identify one or more potential storage areas which have been appropriately assessed and found likely to be suitable for safe geological storage of projected full lifetime volumes and rates of captured CO_2.
- Identify other known factors, including any additional water requirements that could prevent installation and operation of CO_2 capture, transport and storage, and identify credible ways in which they could be overcome.
- Estimate the likely costs of retrofitting capture, transport and storage.
- Engage in appropriate public engagement and consideration of health, safety and environmental issues.
- Review CCS Ready status and report on it periodically.

5.3 Transport of CO_2

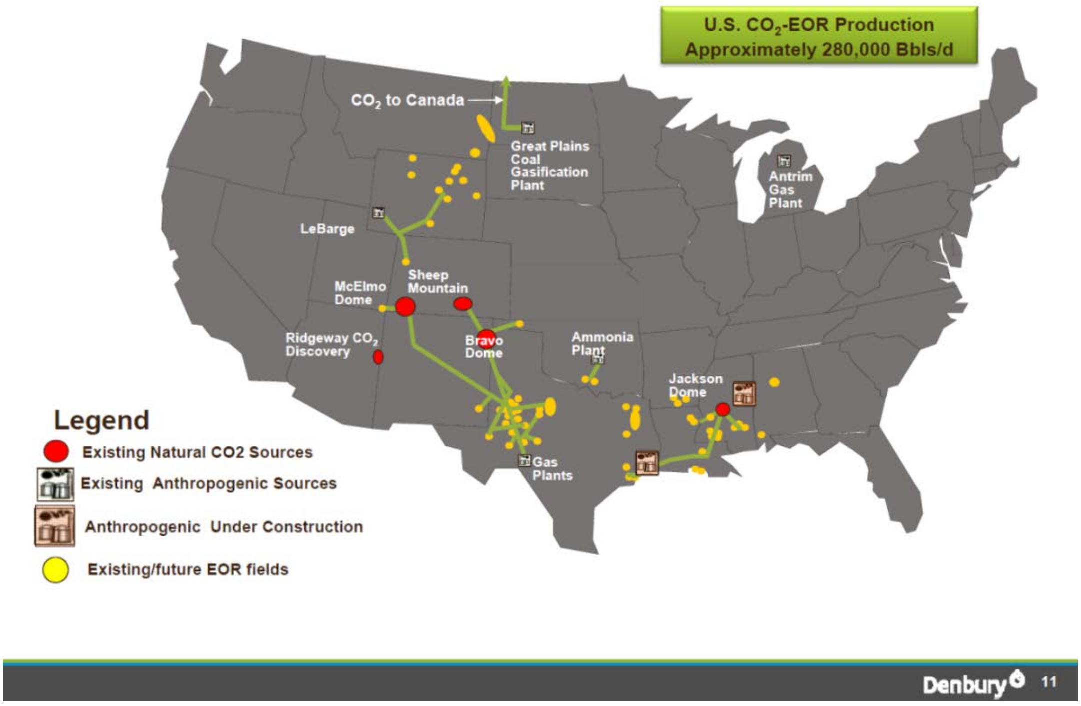
CO_2 is most commonly transported over long distances via pipeline. Gaseous CO_2 is typically compressed to a pressure near 2,200 psi (15.2 MPa) in order to avoid two-phase flow regimes and increase the density of the CO_2, thereby making it easier and less costly to transport.

CO_2 pipeline technology represents a mature technology with a long track record – the first long-distance CO_2 pipeline having been established in 1970 in the Permian basin in West Texas. Alternatively, CO_2 may be chilled, liquefied and transported by ships, tanker trucks, or rail tankers that make use of insulated tanks. However, this method of transport proves impractical when considering the large quantities of CO_2 typically associated with CCS.

There are currently over 4,000 miles of pipeline, carrying some 65 million tonnes of CO_2 annually from natural and anthropogenic sources in the U.S., as shown in Exhibit 69 below. Currently, the U.S. produces more than 280,000 barrels per day of CO_2 EOR oil production.[106]

[106] DOE/NETL 2011, "Improving Domestic Energy Security and Lowering CO_2 Emissions with Next Generation CO_2-EOR.

Exhibit 69: Map of Existing CO_2 Pipelines



Source: Denbury investor slides, April 2012[107]

These pipelines operate in the liquid and supercritical CO_2 phases at ambient temperatures and high pressure. The CO_2 is largely sourced from three naturally occurring deposits in Colorado and New Mexico and transported to West Texas. The Great Plains Coal Gasification Plant in North Dakota and the LaBarge gas plant in western Wyoming are examples of anthropogenic sources that also feed these pipelines.

5.3.1 Potential and Challenges for new CO_2 pipelines

ICF conducted a study for the Interstate Natural Gas Association of America (INGAA) Foundation in 2009 in order to evaluate the potential configuration and scope of a future U.S. CO_2 pipeline network.[108] Prior to the study, little analytical work had been done to evaluate the likely future development of a CO_2 pipeline network and its cost. The study focused on the pipeline infrastructure requirements for CCS in compliance with mandatory greenhouse gas reductions. It concluded that by 2030, between 15,000 and 66,000 miles of pipeline would be required to transport CO_2, depending on how much CO_2 must be sequestered and the extent to which EOR is involved. The study also concluded that while there are no significant technical barriers to building this network, the major challenges will lie in the areas of public policy, regulation, and economics. Because a CCS infrastructure can develop in several ways, it was concluded that the government must address questions about industry structure, government support of early development, regulatory models, and operating rules.

[107] Denbury Resources, 2012, "CO_2 Transportation," Investor Slides, April, 2012, 25p.
[108] INGAA, 2009. http://www.ingaa.org/File.aspx?id=8228

CO_2 pipeline design is similar to natural gas pipeline design, with the exception that thicker pipe is generally needed in order to accommodate higher pressures. The thicker pipes allow for low temperatures that may be associated with rapid pressure reduction or during the initial fill of the line.[109] Primary compressor stations are located where the CO_2 is injected, while booster compressors are located as needed along the rest of the pipeline. Fracture propagation is more likely in CO_2 pipelines as compared to natural gas pipelines due to their slower decompression characteristics. This necessitates the inclusion of fracture arrestors every 1,000 feet to reduce fracture propagation. The presence of impurities lowers the saturation pressure of the gases which affect the susceptibility of pipeline materials to arrest fractures. Thus, the impact of impurities (particularly water to prevent corrosion) needs to be evaluated when designing a CO_2 pipeline. Valve materials must be compatible with CO_2, and CO_2-resistant elastomers are used around valves and other fittings. Unlike existing pipelines, the CO_2 pipeline for CCS will be moving a supercritical fluid that is compressed at the capture plant initially and then pumped into the pipeline. Only long distance pipeline would have additional booster stations.

5.3.2 Cost of CO_2 Pipelines

The costs of building pipelines in the U.S. and Canada have been going up significantly in the last several years, due to higher material and labor costs. Costs can vary significantly from location to location based on the terrain, the density of development along the pipeline route and local construction costs. Since there are large economies of scale for pipelines, CO_2 transportation costs would depend on how many power plants and industrial CO_2 sources could share a pipeline over a given distance. The longer the distance from the source to the CO_2 sink, the more chance there is for other sources to share in the transportation costs.

Recent studies have shown that CO_2 pipeline transport costs for a 62 mile pipeline transporting 5 megatonnes per year range from approximately $1 per tonne to $3 per tonne, depending on factors such as terrain, flow rate, population density, labor costs, etc.[110]

5.3.3 ICF INGAA Analysis – Infrastructure Planning Volumes

For the U.S., the infrastructure planning ranges for CCS volumes are:

- 2015: 3 to 50 million tonnes
- 2020: 25 to 150 million tonnes
- 2030: 300 to 1,000 million tonnes

For Canada, the infrastructure planning ranges for CCS volumes are:

- 2015: 10 to 30 million tonnes

[109] See CCS Task Force Report (2010) for more details.

[110] CCS Task Force, 2010, Report of the Interagency Task Force on Carbon Capture and Storage, Washington, D.C., http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.

- 2020: 30 to 70 million tonnes
- 2030: 90 to 150 million tonnes

The translation of these volumes into transportation infrastructure requirements depends on the location of the CO_2 sources and sinks and the degree to which the CO_2 transportation system is built in an integrated manner in which costs are minimized by combining flows along similar paths into larger pipelines versus built in a piecemeal manner in which most CCS projects construct their own pipeline system.

Including industrial facilities, there are a total of over 1,700 facilities that emit over 100,000 tonnes of CO_2 per year, see Exhibit 70**.** The highest projected annual volume of 1,000 million tonnes per year would be equivalent to the CO_2 amounts that could be captured at about 300 power plants averaging 500 MW in size.

Exhibit 70: Large (> 100,000 tCO_2/yr) CO_2 Sources in US (1,715 in total)

1,053 electric power plants	**259 natural gas processing plants**
126 petroleum refineries	**44 iron and steel foundries**
105 cement kilns	**38 ethylene plants**
30 hydrogen production plants	**19 ammonia plants**
34+ ethanol plants	**7 ethylene oxide plants**

Source: Dooley, 2007 – Battelle PNNL[111]

The transportation issue can be illustrated with the help of Exhibit 71, which is a map of U.S. coal power plants and areas with potential geologic storage sites. Large coal plants in the eastern, midwestern and southern parts of the U.S. are generally located an average of 35 to 60 miles from each other and, in theory, could be connected to nearby storage sites by a network of CO_2 pipelines that has a length of about 50 miles per power plant. However, this would require that a large number of coal plants use CCS and that the power plants share pipeline capacity whenever feasible.

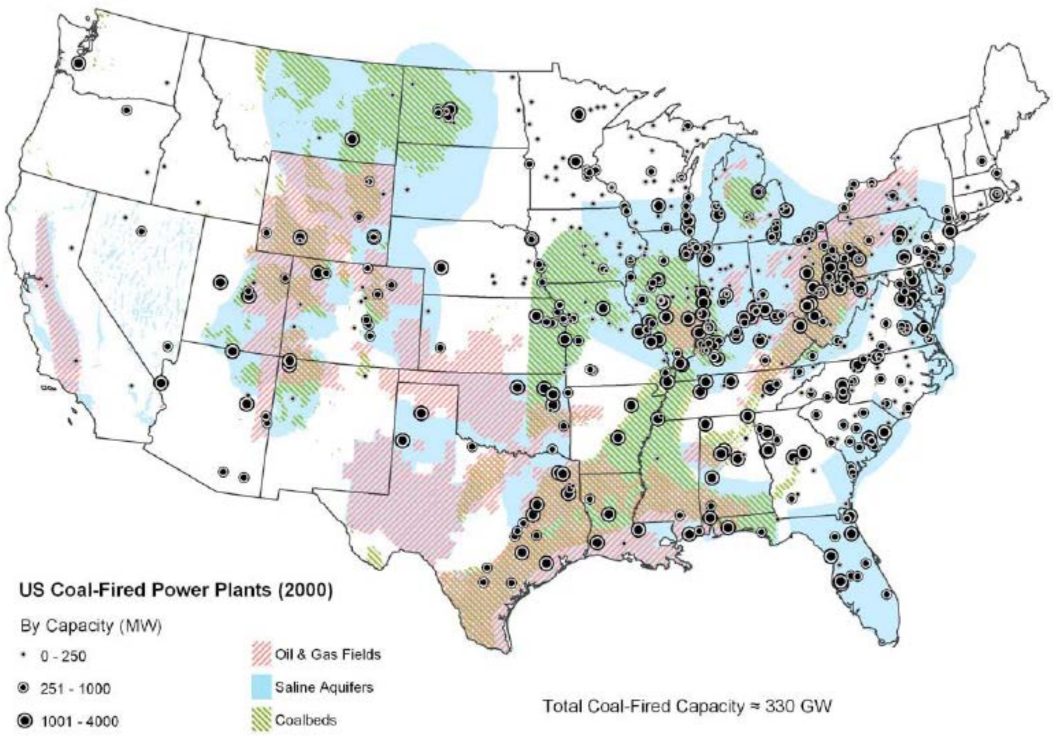
For the INGAA study, ICF developed four cases for a CO_2 pipeline network infrastructure, as shown in Exhibit 72. Two of the cases are based on the High requirements for CCS and two are based on the Low Requirements. In turn, each of the CCS cases is evaluated under scenarios with lesser and greater use of CO_2 for EOR: 25 percent in one versus 75 percent in the other.

The High CCS Case results in additions to the existing CO_2 pipeline network (now about 3,600 miles in length) of 20,610 miles by 2030, when EOR use of CO_2 is modest in scope, and additions of 36,050 miles when EOR use of CO_2 is greater. The cost of constructing the new CO_2 pipeline for the High CCS Case ranges from $32.2 billion to $65.6 billion by 2030 using recent average cost factors. Because construction costs vary greatly based on the

[111] Dr. James Dooley, Pacific Northwest Laboratory, http://www.pnl.gov/

terrain through which the pipeline is built and the prevailing regional materials and labor costs, actual costs may be much greater than this.

Exhibit 71: Map of US Coal Plants and Storage Sites



Source: MIT, The Future of Coal

The Low CCS Case produces a range of new CO_2 pipeline requirements by 2030 of 5,900 to 7,900 miles depending on the degree to which longer distance transport to EOR sites takes place. The cost of this new pipeline would be between $8.5 billion and $12.8 billion.

These results are based on assumptions for distances between captured CO_2 sources and the outputs of ICF's IPM® model. IPM® projects the amounts of CO_2 captured that would likely take place in each electricity generation area and (using the GeoCAT supply curves for various storage options) the amount to geologic storage that would take place in each storage area. The IPM® results were scaled to match this study's assumption for the annual CCS volumes.

The cases with greater use of EOR are based on a more optimistic view of EOR potential that results in an EOR-related storage capacity of 50 gigatonnes versus the 17 gigatonnes for EOR storage in the base GeoCAT data. This larger EOR-related storage volume could come about through the expansion of the oil-in-place that could be targeted by what DOE refers to as "next generation" EOR technologies and the larger amount of CO_2 that could be injected into oil fields if CO_2 were abundant and less expensive than current sources.

Exhibit 72: Cases for U.S. CO_2 Pipeline Requirements

High CCS Case: Lesser Use of CO2 for EOR

	CO2 Pipeline (miles)						
Inch Diameter	12.75	16	24	30	36	42	All Diameters
Miles Needed by 2015	550	270	90	0	0	0	910
Miles Needed by 2020	1,250	830	500	270	100	0	2,950
Miles Needed by 2030	7,190	5,700	4,150	2,500	1,070	0	20,610
	CO2 Pipeline Expenditures ($ millions)						
Expenditures by 2015	526	337	181	0	0	0	1,044
Expenditures by 2020	1,195	1,036	1,008	697	320	0	4,256
Expenditures by 2030	6,875	7,114	8,366	6,450	3,428	0	32,234

Low CCS Case: Lesser Use of CO2 for EOR

	CO2 Pipeline (miles)						
Inch Diameter	12.75	16	24	30	36	42	All Diameters
Miles Needed by 2015	40	0	0	0	0	0	40
Miles Needed by 2020	280	140	50	0	0	0	470
Miles Needed by 2030	2,500	1,660	1,000	540	200	0	5,900
	CO2 Pipeline Expenditures ($ millions)						
Expenditures by 2015	38	0	0	0	0	0	38
Expenditures by 2020	268	175	101	0	0	0	543
Expenditures by 2030	2,391	2,072	2,016	1,393	641	0	8,512

High CCS Case: Greater Use of CO2 for EOR

	CO2 Pipeline (miles)						
Inch Diameter	12.75	16	24	30	36	42	All Diameters
Miles Needed by 2015	550	270	90	0	0	0	910
Miles Needed by 2020	1,310	1,110	780	530	350	0	4,080
Miles Needed by 2030	7,960	9,560	8,010	6,050	4,470	0	36,050
	CO2 Pipeline Expenditures ($ millions)						
Expenditures by 2015	526	337	181	0	0	0	1,044
Expenditures by 2020	1,253	1,385	1,572	1,367	1,121	0	6,699
Expenditures by 2030	7,612	11,931	16,148	15,609	14,322	0	65,622

Low CCS Case: Greater Use of CO2 for EOR

	CO2 Pipeline (miles)						
Inch Diameter	12.75	16	24	30	36	42	All Diameters
Miles Needed by 2015	40	0	0	0	0	0	40
Miles Needed by 2020	280	130	40	-10	-10	0	430
Miles Needed by 2030	2,600	2,160	1,500	1,000	640	0	7,900
	CO2 Pipeline Expenditures ($ millions)						
Expenditures by 2015	38	0	0	0	0	0	38
Expenditures by 2020	268	162	81	-26	-32	0	453
Expenditures by 2030	2,486	2,696	3,024	2,580	2,051	0	12,836

5.3.4 Determining Factors for Future CO_2 Pipeline Development

The key factors determining the location and scale of CO_2 transport corridors include the following:

- Location and nature of CO_2 sources
- Location and economics of CO_2 storage options
- Distance between source and storage sites
- Low population density
- Limited changes in elevation across the pipeline route, limited water body crossings, and reduced crossings of any environmentally sensitive zones
- Availability of any existing right of way (e.g., linking with electric transmission corridors)
- Resolution of regulatory and legal issues related to CO_2 storage in various settings
- Whether or not storage is allowed offshore

Many in industry expect that the early storage projects would have a dedicated pipeline system and would for the most part use nearby storage sites. This expectation stems from the belief that power plants near storage sites would be the most economic and, therefore, would be the first to convert to or be built with CCS. There is also the expectation that in the early phases of the CCS industry, a single entity would control the entire CCS project (capture, transport and storage) to better manage commercial, regulatory and liability risks. Such projects might frequently be expected to be undertaken by a regulated utility that will put the entire project within the jurisdiction of the relevant regulatory commission.

Over time, as more CCS plants are developed there will be a tendency to connect plants that are further away from storage sites. However, the greater density of CCS plants and increased imperative to reduce transportation costs for longer distance transportation would lead to more shared pipelines as CCS grows. Under this view, the later CCS development would tend to have larger diameter pipelines than in the early phase. The pipeline network mileage averaged per CO_2 source, may be similar between the early and later development phases, since that larger source-to-sink distances in the later phase would be offset by sharing of pipeline capacity.

Another important determinant of the evolution of the CO_2 pipeline network will be the degree to which the CO_2 will be used for EOR. The spatial distribution to saline reservoirs is much wider and the estimated capacity is 175 times larger for than for EOR. Therefore, it is statistically more likely that a CO_2 source will have a suitable saline reservoir closer to it.[112]

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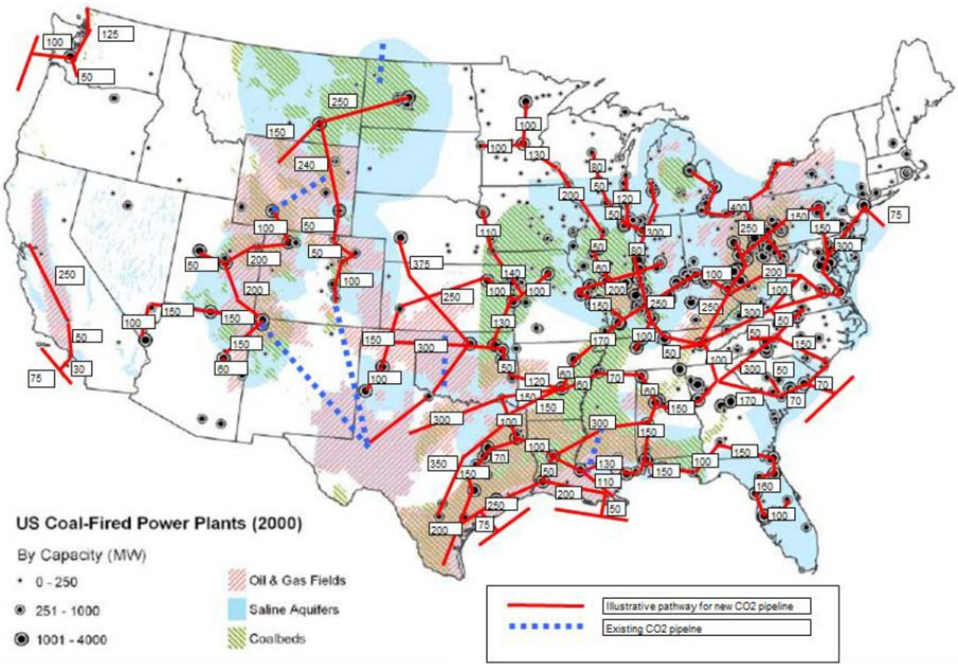
[112] However, it should be emphasized that not all saline reservoirs will be suitable for long term CO_2 storage due to poor reservoir characteristics (low porosity and permeability), lack of an impermeable

This means that if the storage network serves EOR to a very large degree, it will likely be transporting CO_2 over longer distance than a system that moves CO_2 from sources to saline reservoirs.

Finally, if "NIMBY" concerns become to dominate the public concerns on CO_2 storage, then one potential option is storage in offshore areas—in particular offshore areas where EOR is possible (e.g., offshore Louisana and Texas).

One possible layout of the U.S. CO_2 pipeline system for the INGAA case requiring the most pipeline development (High CCS Case with Greater Use of EOR) is shown in Exhibit 73. The new mainline corridors depicted as red lines in the map sum to 13,500 miles. Adding pipeline mileage for the expected multiple pipelines on many corridors and pipeline required to connect individual sources and sinks to the system yields the total new transmission pipeline requirement of 36,050 miles. The High CCS Case with Lesser Use of EOR would not require this degree of interconnectivity and would not show as much new capacity going into the oil producing areas. This case also shows the development of offshore pipelines in the Gulf of Mexico, Atlantic and Pacific offshore basins.

Exhibit 73: Map of Possible CO_2 Pipeline Corridors for a High CCS Case with Greater Use of EOR[113]



Source: INGAA. Developing a Pipeline Infrastructure for CO_2 Capture and Storage: Issues and Challenges

5.4 Storage of CO_2

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cap rock to restrict CO_2 escape, excessive discontinuous features and faulting, a too-thin thickness that will require a large surface area be disturbed or affected and proximity to densely populated areas that will make land difficult to assemble and facilities permits difficult to obtain.

[113] INGAA, 2009. http://www.ingaa.org/File.aspx?id=8228

There are several different options for long term 'permanent' carbon dioxide storage[114]: a) ocean storage by pumping CO_2 deep into the bottom of the ocean, b) chemical storage by binding CO_2 with other chemicals to form an inert substance, and c) geological storage by pumping CO_2 underground into depleted oil and natural gas reservoirs and in deep saline reservoirs. Of the three options, geological storage is the most promising for storage of large scale emissions.

Injection of CO_2 in deep geological reservoirs below the Earth surface – i.e., geological storage – is becoming an important option for storing large scale CO_2 captured from power plants and other industrial facilities. There are active demonstration projects for injecting and storing CO_2 in depleted oil and gas reservoirs, enhanced oil and gas production, and deep saline aquifers. In addition, R&D projects are investigating the suitability of unmineable coal beds and deep water-saturated mineral rocks.

Underground injection of CO_2 is a commercial technology and it has been used since the 1970s for enhanced oil recovery (EOR) – wherein CO_2 and water is periodically injected to extract more oil out of a reservoir. Although injecting CO_2 for EOR is not aimed at storage (especially since injectors have to purchase CO_2), a fraction of the injection CO_2 remains captured in the reservoir. The CO_2 for EOR is currently sourced from both natural and anthropogenic sources, which provide 79 percent and 21 percent, respectively, of CO_2 supply.[115] Some of the natural CO_2 reservoirs include the Bravo Dome (New Mexico), McElmo Dome (Colorado), Escalate Reservoir (Utah), Farnham Reservoir (Utah), Woodside Reservoir (Utah), and LaBarge Dome (Wyoming)[116].

Commercial-scale engineered CO_2 storage projects are already underway in Norway (North Sea), Canada (Weyburn), and Algeria (In Salah) with many future projects more planned in Canada, China, Australia, U.S.A., Japan, and the EU.[117] The technology for injecting gases into geological media is well established,[118] and it requires many of the same technologies developed in the oil and gas exploration and production industry, such as include well drilling, injection, reservoir capacity/storage assessment, simulation of reservoir dynamics, monitoring methods, etc.

5.4.1 Storage Options

Geological formations most suitable for storage are in sedimentary basins, wherein the subsurface has mineral rock formations, organic matter, cavities and fissures. The pore spaces, cavities and open fractures are mainly filled with water and with oil and gas in a

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[114] Biological sequestration (such as enhancing of natural sinks such as forests and soil) is not directly applicable to power plant emissions.

[115] CCS Task Force, 2010, Report of the Interagency Task Force on Carbon Capture and Storage, Washington, D.C., http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.

[116] CCS Task Force, 2010, Report of the Interagency Task Force on Carbon Capture and Storage, Washington, D.C., http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.

[117] See: http://sequestration.mit.edu/tools/projects/ and http://www.globalccsinstitute.com/publications/global-status-ccs-update-january-2013

[118] Fluids have been injected into the deep subsurface for a long time to dispose of unwanted chemicals, pollutants, and petroleum by-products to enhance oil and gas recovery. Natural gas has also been injected and stored in sub-surface reservoirs in many places (IPCC, 2005).

small number of locations worldwide. Target formations with the greatest geologic storage capacity include deep saline formations, depleted oil and gas reservoirs, unmineable coal seams, and other formations[119]:

Deep saline formations: These formations are sedimentary rock layers that are more than 800 meters deep and saturated with brines that have a high total dissolved solids (TDS) content (i.e., over 10,000 mg/L TDS). Deep saline formations are found throughout the United States. The formations suitable for storage are overlain by laterally extensive, impermeable formations that may restrict upward movement of injected CO_2.

Depleted oil and gas reservoirs: These reservoirs are prime candidates for CO_2 storage because of their demonstrated structural integrity (by storing hydrocarbons in physical traps, sometimes for many millions of years). The same trapping mechanisms in which hydrocarbons are commonly found (i.e., structural trapping by faulted, folded, or fractured formations, or stratigraphically, in porous formations bounded by impermeable rock formations) can effectively store CO_2 for geologic sequestration in depleted oil and gas reservoirs.

Unmineable coal seams: Coal seams that are inaccessible to mining can be used to store CO_2 using adsorption trapping. Currently, enhanced coalbed methane (ECBM) operations exploit the preferential chemical affinity of coal for CO_2 relative to the methane that is naturally found on the surfaces of coal. Studies suggest that for every molecule of methane displaced in ECBM operations, three to thirteen CO_2 molecules are adsorbed. Higher coal rank might enhance the relative adsorptive capacity of methane and CO_2 (Reeves et al., 2004). This process effectively "locks" the CO_2 to the coal, where it remains sequestered. However, permeability of coal for CO_2 is an issue, and the permeability decreases with increasing depth. Therefore, the feasibility of using coal seams for large-scale CO_2 storage is still uncertain.

Several other types of geological formations are being explored as potential storage options, including basalts, salt caverns, unused mines, underground coal gasification (UCG) voids, shales, and deep cool sub-surface storage as liquid CO_2 and CO_2 hydrate. Technology for storage in these options and scientific understanding is at research stage.

5.4.2 Storage Site Phases

The geology and geological attributes of the subsurface are highly variable among regions, basins, and even among sites within any basin. Therefore, the appropriateness of a storage site has to be determined through a process of site characterisation and selection of potential sites. The appropriateness of a storage site (mostly defined by the safe and permanent storage of CO_2) is determined primarily by three principal requirements:

- Capacity: i.e., whether sufficient storage volume is available and can be accessed;
- Integrity: i.e., whether the site is secure with negligible risk of leakage;

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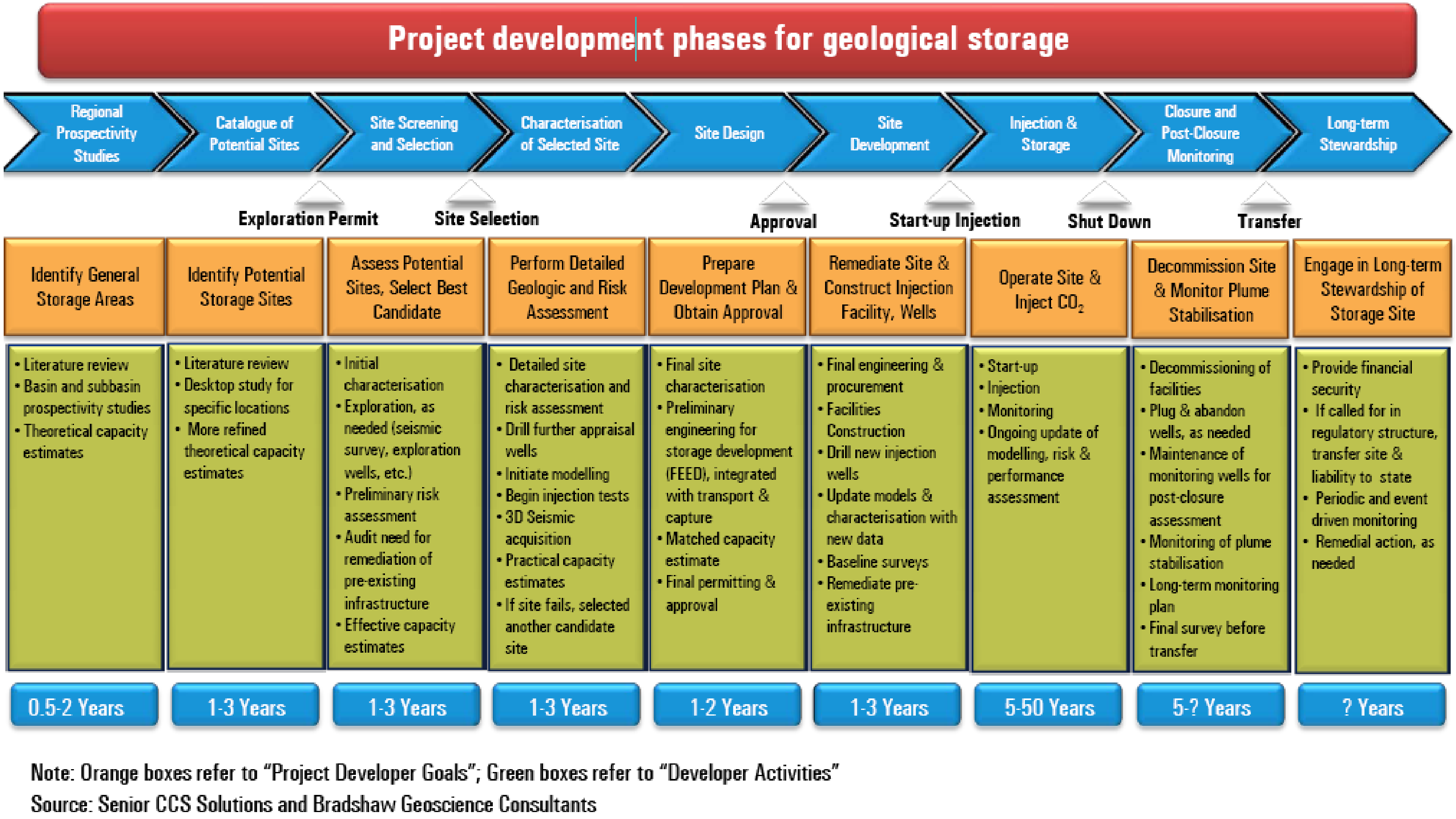
[119] CCS Task Force, 2010, Report of the Interagency Task Force on Carbon Capture and Storage, Washington, D.C., http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.

- Injectivity: i.e., whether suitable reservoir properties exist for sustained injection at industrial supply rates into the geological formations, or whether the reservoir properties can be engineered to be suitable.[120]

The entire chain of activities needed for the entire lifecyle of a CO_2 storage site is shown below in Exhibit 74. As one passes through these different stages, a storage site developer achieves progressively more detailed knowledge about the storage capacity of the site and the characteristics of the storage reservoir, with reduction in uncertainty and better understanding of technical risks. The timeframes in Exhibit 74 are generic in nature, and actual timeframes for specific projects will depend on the site characteristics, scope of activities required, regulatory frameworks and the industry environment as well as public attitudes to the project and how long it takes to gain public acceptance.

[120] For example, by fraccing the reservoir or by extracting formation water to prevent reservoir pressure build-up.

Exhibit 74: Phases of Geological Storage of CO_2



Note: Orange boxes refer to "Project Developer Goals"; Green boxes refer to "Developer Activities"

Source: Senior CCS Solutions and Bradshaw Geoscience Consultants

Source: ICF/GCCSI 2010

5.4.3 U.S. Storage Capacity

Capacity estimates in the United States are regionally variable, but details are being refined in ongoing efforts (e.g., in both DOE and USGS). DOE and International Energy Agency capacity estimates suggest that the United States may have storage potential for more than 3,000 billion tonnes of CO_2—large enough to store the amount of CO_2 emissions currently emitted from the entire coal fired electricity sector in the United States for over 1,000 years.[121]

The U.S. Department of Energy has compiled an assessment of North American CO_2 geological storage potential. This has been documented in the NATCARB Atlas.[122] NATCARB stands for the National Carbon Sequestration Database and Geographic Information System, which is a geographic information system (GIS)-based tool developed to provide a view of carbon capture and storage (CCS) potential.[123] Supported by U.S. DOE, the information in NATCARB is provided by various entitites, including the seven regional partnerships covering the Lower-48 and western Canada.[124] Exhibit 75 is a map showing potential CO_2 storage basins by geologic category (oil and gas, coal, and saline). It also shows major point sources of CO_2 emissions as defined for the atlas (>1,000 tons per year).

Exhibit 76 summarizes the results of the 2010 NATCARB regional assessments. Lower-48 total storage potential is 11,087 Gigatonnes (Gt). Almost all of the assessed potential is in saline reservoirs (10,889 Gt) with some potential in depleted fields (109 Gt), CO_2 enhanced oil recovery (17 Gt), and a minor amount in coal beds (73 Gt).

In 2012, DOE released a new edition of the NATCARB Atlas that contains only minor changes.[125] The revised Lower-48 total is 11,180 Gt, an increase of only 100 Gt. The main difference in the assessments is an increase in oil and gas reservoir potential to 207 Gt.

CO_2-Enhanced Oil Recovery (EOR) storage has a "negative cost" because of the value of the additional crude oil produced. Under a future cap and trade system, the initial storage will occur in areas with CO_2-EOR potential. As shown in Exhibit 76, most of this potential is in West Texas, the Mid-Continent, and the Rockies. Only after this storage potential is exhausted will large volumes be stored in saline reservoirs. The 16.5 Gt of CO_2-EOR potential is an ICF estimate derived from information on U.S. EOR potential by area. The estimate is based on ICF's supply curves of storage economics, by type of storage and geographic area for the U.S.

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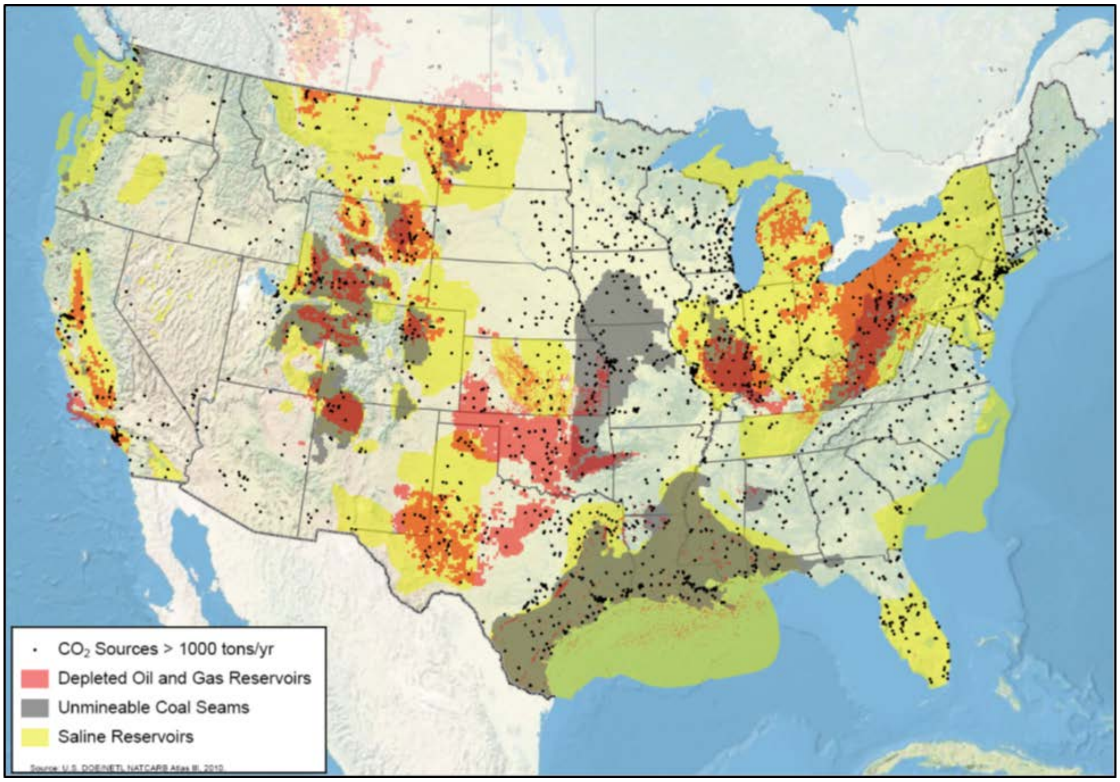
[121] The coal fired electricity sector emitted 1,945.9 million tonnes of CO_2 in 2008. (EIA, 2009)

[122] U.S. Department of Energy, 2010, "2010 Carbon Storage Atlas of the United States and Canada (Volume III)," (NATCARB Atlas), DOE Morgantown, WV, http://www.netl.doe.gov/technologies/carbon_seq/natcarb/index.html.

[123] http://www.netl.doe.gov/technologies/carbon_seq/natcarb/index.html
[124] http://www.netl.doe.gov/technologies/carbon_seq/infrastructure/rcsp.html
[125] http://www.netl.doe.gov/technologies/carbon_seq/natcarb/download.html

Exhibit 75: Map of CO_2 Storage Basins by Type and Major Point Sources



Source: NATCARB GIS database

Exhibit 76: North America CO_2 Geologic Storage Potential[126]

Gigatonnes Region	Non-EOR Depleted Oil and Gas	CO2 Enhanced Oil Recovery*	Coal Seams Low	Coal Seams High	Coal Seams Calc. Midpoint	Saline Formations Low	Saline Formations High	Saline Formations Calc. Midpoint	Assessed Total Low	Assessed Total High	Assessed Total Calc. Midpoint
Williston Basin and Western Canada	**24.4**	**0.6**	1.0	1.0	**1.0**	165	165	**165**	191	191	**191**
Illinois Basin	**0.9**	**0.1**	1.6	3.3	**2.5**	12	160	**86**	15	164	**89**
Michigan and Appalachia	**16.9**	**0.1**	0.8	1.9	**1.4**	46	183	**115**	64	202	**133**
Gulf Coast, GoM, and Atlantic Offsh.	**28.8**	**3.2**	33.0	75.0	**54.0**	908	12,526	**6,717**	973	12,633	**6,803**
California, Pac. NW, Pac. Offsh., AK	**2.8**	**1.2**	10.0	23.0	**16.5**	82	1,124	**603**	96	1,151	**624**
S. Rockies, Mid-Cont.,West Texas	**51.2**	**10.7**	1.0	2.0	**1.5**	219	3,013	**1,616**	282	3,077	**1,679**
N Rockies, W. Montana	**1.6**	**0.6**	12.0	12.0	**12.0**	221	3,041	**1,631**	235	3,055	**1,645**
North America Total	**126.6**	**16.5**	59.4	118.2	**88.8**	1,653	20,212	**10,933**	1,856	20,473	**11,164**
Alaska	**0.0**	**0.0**	9.0	21.0	**15.0**	0	0	**0**	9	21	**15**
Canada	**18.0**	**0.0**	0.8	0.8	**0.8**	38	51	**44**	57	70	**63**
L48 Total	**108.6**	**16.5**	49.6	96.4	**73.0**	1,614	20,163	10,889	1,790	20,383	**11,087**
onshore	**93.6**	**15.0**	48.3	93.3	**70.8**	1,123	13,407	**7,265**	1,280	13,609	**7,444**
offshore	**15.0**	**1.5**	1.3	3.1	**2.2**	491	6,756	**3,624**	509	6,776	**3,643**

Source: NATCARB Atlas; ICF estimates (EOR)

[126] 2010 NATCARB Atlas for all except CO_2 EOR, which is an ICF estimate upon DOE assessments of EOR potential.

ICF developed an independent model, called the Geologic Sequestration Cost Analysis Tool (GeoCAT) model, to evaluate the economics associated with injecting and storing for CCS for the entire inventory of U.S. geologic storage potential.

Exhibit 77 shows the breakout of assessed storage potential by state and offshore area. Offshore potential is 3,600 out of 11,000 Gt. Most of the offshore potential is in Gulf of Mexico saline strata.

Exhibit 77: North America CO_2 Geologic Storage Potential by State

	ICF	ICF	ICF	ICF	ICF	
	CO2 EOR	Depleted Oil	Coal Beds	Saline	Lower-48	Lower-48
	Mid	Mid	Mid	Mid	Mid	Mid
	Volume	Volume	Volume	Volume	Volume	NATCARB
State or Area	Gtonne	Gtonne	Gtonne	Gtonne	Gtonne	Gtonne
ALABAMA	0.07	0.28	3.13	86.70	90.2	90.2
ARIZONA	0.00	0.01	0.00	0.85	0.9	0.9
ARKANSAS	0.08	0.18	2.58	31.87	34.7	34.7
ATLANTIC OFFSHORE	0.00	0.00	0.00	317.00	317.0	317.0
CA. ONSHORE	1.24	2.20	0.00	221.78	225.2	225.2
COLORADO	0.20	1.41	0.68	227.60	229.9	229.9
DELAWARE	0.00	0.00	0.00	0.05	0.1	0.1
FLORIDA	0.13	0.00	2.03	116.33	118.5	118.5
GEORGIA	0.00	0.00	0.05	11.85	11.9	11.9
IDAHO	0.00	0.00	0.00	0.39	0.4	0.4
ILLINOIS	0.10	0.00	2.16	61.91	64.2	64.2
INDIANA	0.02	0.00	0.14	49.91	50.1	50.1
IOWA	0.00	0.00	0.01	0.08	0.1	0.1
KANSAS	0.41	1.18	0.01	8.80	10.4	10.4
KENTUCKY	0.01	0.04	0.19	5.40	5.6	5.6
LA. OFFSHORE	1.46	9.61	0.00	2,133.07	2,144.1	2,144.1
LA ONSHORE	1.36	9.25	13.61	1,101.56	1,125.8	1,125.8
MARYLAND	0.00	0.00	0.00	2.96	3.0	3.0
MICHIGAN	0.08	0.69	0.00	36.56	37.3	37.3
MINNESOTA	0.00	0.00	0.00	0.00	0.0	0.0
MISSISSIPPI	0.13	0.43	8.96	335.20	344.7	344.7
MISSOURI	0.00	0.00	0.01	0.17	0.2	0.2
MONTANA	0.25	2.35	0.32	887.22	890.1	890.1
N. DAKOTA	0.32	4.09	0.60	111.65	116.7	116.7
NEW MEXICO	0.90	6.45	0.19	236.89	244.4	244.4
NEBRASKA	0.02	0.01	0.00	49.85	49.9	49.9
NEVADA	0.00	0.00	0.00	0.00	0.0	0.0
NEW ENGLAND STS	0.00	0.00	0.00	0.00	0.0	0.0
NEW JERSEY	0.00	0.00	0.00	0.00	0.0	0.0
NEW YORK	0.00	0.92	0.00	4.26	5.2	5.2
N. CAROLINA	0.00	0.00	0.00	9.75	9.7	9.7
OHIO	0.00	10.06	0.13	9.94	20.1	20.1
OKLAHOMA	1.41	6.71	0.01	0.00	8.1	8.1
OREGON	0.00	0.00	0.00	52.24	52.2	52.2
PACIFIC OFFSHORE	0.00	0.20	2.30	108.00	110.5	110.5
PENNSYLVANIA	0.00	2.97	0.28	17.26	20.5	20.5
S. DAKOTA	0.00	0.19	0.00	86.69	86.9	86.9
S. CAROLINA	0.00	0.00	0.00	4.93	4.9	4.9
TENNESSEE	0.00	0.00	0.00	3.57	3.6	3.6
TEXAS ONSHORE	7.55	38.65	22.82	2,458.83	2,527.8	2,527.8
TX. OFFSHORE	0.00	5.53	0.00	1,064.93	1,070.5	1,070.5
UTAH	0.28	0.88	0.08	154.84	156.1	156.1
VIRGINIA	0.00	0.06	0.49	0.24	0.8	0.8
WASHINGTON	0.00	0.00	0.00	220.75	220.8	220.8
WEST VIRGINIA	0.00	1.83	0.41	11.21	13.4	13.4
WISCONSIN	0.00	0.00	0.00	0.00	0.0	0.0
WYOMING	0.42	1.88	12.00	644.82	659.1	659.1
Lower 48 Total	16.45	108.05	73.13	10,887.8	11,087.0	11,085.4
Offshore L-48	1.46	15.34	2.30	3,623.0	3,643.0	3,642.1

Source: NATCARB Atlas; ICF estimates (EOR)

It must be pointed out that the DOE capacity estimates are highly uncertain due to both the uncertainty of the underlying data regarding the geologic formations, as well as their methodology. The DOE method attempts to evaluate the entire storage resource base across all regions and stratigraphic intervals. It uses a volumetric approach for each geologic formation that evaluates area, net thickness, and porosity, and applies a “storage efficiency factor” to estimate the fraction of the volumetric pore space that the CO_2 is expected to contact. For example, the storage efficiency factor for saline formations has several components that reflect different physical barriers within the system that prevent CO_2 from contacting portions of the volume. The full methodology is available on the DOE website.[127] Two recent papers[128] have been critical of the DOE methodology because it does not directly take into account the dynamics of the geological system, in particular the build-up of pressure.

A recent study carried out by MIT[129] has incorporated these dynamic considerations in their analysis. The MIT study evaluates eleven major saline formations in the Midwest, Rockies, Texas, and Gulf Coast regions. Each formation was evaluated volumetrically and cutoffs were applied on the basis of the fraction of the pore space that is accessible for CO_2 injection. The formations were selected because they are large, are relatively unfaulted, and are well studied. The approach to evaluating storage capacity is fundamentally different from the volumetric estimates of DOE in that it is based upon developing a storage supply curve derived from volumetrics as well as the fluid mechanics of CO_2 injection and trapping and incorporates injection rate constraints. On a pure volumetric basis for studied formation, their results were similar to that of DOE. They evaluate the lifetime of U.S. CCS as the time for which the storage supply curve exceeds the demand from CO_2 production. They conclude that using certain assumptions, the U.S. has sufficient storage capacity to accommodate emissions from power plants for over 100 years. Because of the nature of their assessment, they publish the formation storage volumes in gigatonnes as a function of years of injection. At 600 years, the volume of storage is 314 Gt CO_2.

5.4.4 Storage Costs

The cost of storage in geological subsurface varies according to site-specific factors such as onshore vs. offshore, reservoir depth, and geological characteristics. Costs associated with CO_2 storage have been estimated to be approximately \$0.4–20/tonne.[130] Representative cost

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[127] http://www.netl.doe.gov/technologies/carbon_seq/natcarb/geologic-storage-estimates-for-carbon-dioxide-sept2010.pdf

[128] Ehlig-Economides, C & Economides, M. J. (2010) Sequestering carbon dioxide in a closed underground volume. J. Pet. Sci. Eng. 70, 118-125.

Zoback MD, Gorelick SM (2012) Earthquake triggering and large-scale geologic storage of carbon dioxide. Proc Natl Acad Sci USA 109(26):10164–10168.

[129] Szulczewski, M., MacMinn, C., Herzog, H., and Juanes, R., 2012, “Lifetime of Carbon Capture and Storage as a Climate Change Mitigation Technology,” April 3, 2012. http://www.ethicalgrid.com/blog/wp-content/uploads/2012/03/CCS_study3.pdf

[130] Cost estimates are limited to capital and operational costs, and do not include potential costs associated with long-term liability.

estimates in saline formations and depleted oil and gas reservoirs are between \$0.4-12/tCO_2 injected, with an addition \$0.16-0.30/tCO_2 for monitoring and verification.[131] When CO_2 storage is combined with EOR or CBM, the economic value of CO_2 can result in a net benefit for injecting CO_2 underground.[132]

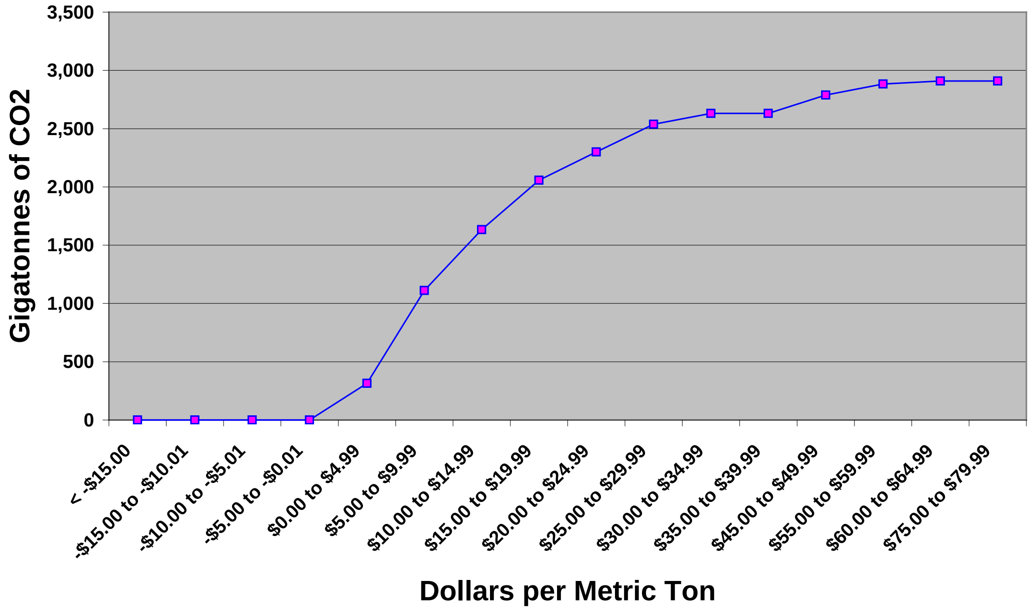
ICF has developed more detailed modeling of storage costs for DOE and EPA, including capital and operating costs for pumps, pipelines, injection wells and monitoring wells and equipment. These costs are typically functions of key engineering parameters such as depth, pressure and flow rate. Other cost elements are initial geological and geophysical (G&G) survey and regulatory costs for site selection, permitting and certification and recurring non-well monitoring during the project injection period and afterwards. There are also cost parameters for contingencies and for general and administrative costs (a.k.a. owner's costs). Payments to the landowner for surface disturbance and injection rights are included as are "insurance payments" to a government entity that is assumed to take over long-term liability for the site after its abandonment.

Exhibit 78 shows an aggregrate cost curve for the geologic storage potential in saline reservoirs in the U.S. Exhibit 78 shows that, most of the storage potential is characterized by costs of less than \$25 per tonne. A substantial volume of potential was evaluated to cost less than \$15/tonne.

[131] IPCC, 2005, "IPCC Special Report on Carbon Dioxide Capture and Storage," by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

[132] Data for onshore EOR indicates a net benefit of \$10-16/tCO_2, including costs of geological storage. With the price of oil and gas increasing, the economic value of CO_2 might even be higher (IPCC, 2005).

Exhibit 78: Summary of Economic Analysis of Saline Reservoir Potential in the United States



Source: INGAA

5.5 CCS Permitting Issues

This section provides a summary of ongoing regulatory efforts related to CCS permitting, with a focus on the EI states. Appropriate regulations and legal guidelines are critical for supporting the widespread deployment of CCS. In the United States, there are already a number of regulations aimed at permitting, as well as address other legal issues (see next section). These regulations are at both the federal and state-level, and they are briefly discussed below.

5.5.1 Storage

Federal and State UIC Programs

The primary regulatory framework applicable to the underground injection of fluids[133] for the purpose of storage is the Federal Underground Injection Control (UIC) Program, under the Safe Drinking Water Act (SDWA). The Federal UIC Program is responsible for regulating the construction, operation, permitting, and closure of injection wells to prevent contamination of underground sources of drinking water (USDWs). Injection wells are grouped into six distinct classes. This allows consistent technical requirements to be applied to each well class.

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[133] "Fluid" is defined as "any material or substance which flows or moves whether in a semisolid, liquid, sludge, gas, or any other form or state." 40 CFR § 144.3.

The U.S. Environmental Protection Agency (EPA) is responsible for implementing the Federal UIC Program. State agencies can submit an application to EPA to obtain primary enforcement responsibility, or primacy, for the UIC program in whole or for some classes of wells. State agencies that have been granted this authority oversee the injection activities in their states. The EPA continues to directly implement the UIC Program in states that have not obtained primacy.

The EPA applies the same standard for primacy determinations for all classes of UIC wells, except for Class II. With the exception of Class II wells, a state must develop regulations that are at least as stringent as the corresponding Federal requirements. Class II wells, which are used to inject fluids associated with oil and natural gas production (e.g., enhanced oil recovery (EOR) wells), are not held to this same standard because Congress directed the EPA to not interfere with oil and gas production under this law. Therefore, states applying for primacy for Class II wells are not required to demonstrate that their regulatory program is as stringent as the Federal program, but instead must meet a lower threshold by demonstrating that the state's regulatory program will protect underground drinking water. Currently, authority for the implementation of the UIC Program is as follows:

- State agencies have primacy for all classes of UIC wells (except Class VI) in 34 States
- EPA directly implements nationally the Class VI Program for underground geologic sequestration (GS) of CO_2
- EPA directly implements the UIC Program for all classes of wells in 10 States
- EPA has joint authority with state agencies for implementing the UIC Program in 7 States

Exhibit 79 provides an overview of federal UIC permitting regulations applicable to CCS, including the Class VI regulations specifically addressing UIC wells used for GS of CO_2. Exhibit 79 entries address the following regulation components:

- *Lifespan of Permit*: Duration of a permit and any requirements for renewal.
- *Financial Responsibility Requirements:* Scope of the financial responsibility required under the permit.
- *Operational Requirements for Monitoring, Mitigation, and/or Corrective Action[134]:* Requirements applicable during injection and up until the site is certified as closed.
- *Post-closure Requirements for Monitoring, Mitigation, and/or Corrective Action:* Requirements applicable after certification of site closure.

[134] "Corrective Action" is defined as the actions necessary to prevent movement of fluid into USDWs." 40 CFR § 144.55.

Each row includes a hyperlink to the applicable Code of Federal Regulations section for further information on the permitting process, including necessary submissions, signatures, fees, deadlines, renewal processes, etc.

As of January 2013, EPA is directly implementing the Class VI UIC program in all states and has not received any complete applications for state primacy. EPA has reported being in discussions about Class VI primacy with at least 10 States and that North Dakota, Mississippi, and Louisiana are among those States furthest along in the application process. North Dakota was working with EPA Region 8 and Headquarters throughout 2012 to develop draft application materials and is expected to submit a complete Class VI primacy application in April 2013. Mississippi has indicated to EPA that it will adopt federal Class VI regulations by reference, but plans are still tentative as to when a complete primacy application will be submitted to EPA. Similarly, Louisiana has been in discussion with EPA about Class VI primacy in 2012, but EPA has no specific expectations regarding a timeline for application submission.[135]

[135] U.S. Environmental Protection Agency, *The EPA Class VI GS Rule: Regulation and Implementation* (Jan. 29, 2013), *available at* http://www.gwpc.org/sites/default/files/event-sessions/Kobelski_Bruce.pdf.

Exhibit 79: Summary of Federal UIC Regulations

Program/ Applicability	Lifespan of Permit	Financial Responsibility Requirements	Operational Requirements for Monitoring	Operational Requirements for Mitigation and/or Corrective Action	Post-Closure Requirements for Monitoring	Post-Closure Requirements for Mitigation and/or Corrective Action
UIC Class II: wells used to inject fluids associated with oil and natural gas production -Includes wells used to inject CO_2 into oil-bearing formations to recover residual oil and natural gas.	-A permit must be issued before construction of a well may begin -Lifespan of operations -Reviewed every 5 years	Demonstrate and maintain financial responsibility and resources to close, plug, and abandon the underground injection operation.	Monitor the nature of injected fluids at time intervals sufficiently frequent to yield data representative of their characteristics (e.g., injection pressure, flow rate, cumulative volume).	Permits shall contain requirements for corrective action, when applicable.	Requirements for monitoring the nature and composition of all injected fluids until three years after the completion of any plugging and abandonment procedures.	Permits shall contain requirements for corrective action, when applicable.
UIC Class V: all injection wells not otherwise included under Class I, II, III, IV, or VI -Includes wells used for pilot GS projects that are experimental in nature.	-A permit must be issued before construction of a well may begin -Effective for a fixed term not to exceed 10 years	N/A	Perform ground water monitoring and periodically submit monitoring results.	N/A	N/A	N/A
UIC Class VI: wells used for injection of CO_2 into underground subsurface rock formations for long-term storage -Includes wells used to permanently store CO_2 underground.	-A permit must be issued before construction of a well may begin -Operating life of the facility and the post-injection site care period -Reviewed every 5 years	Demonstrate and maintain financial responsibility and resources -to close, plug, and abandon the underground injection operation, -for post injection site care and closure, and -for emergency and remedial response to address endangerment of	Prepare, maintain, and comply with a testing and monitoring plan to verify that the GS project is operating as permitted and is not endangering underground sources of drinking water (USDWs).	Corrective action must be performed on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the CO_2 stream, where appropriate.	Following the cessation of injection, continue to conduct monitoring as specified in post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe. Monitoring must continue until the GS project no longer poses an endangerment to	Post-injection site care means appropriate monitoring and other actions (including corrective action) needed following cessation of injection to ensure that USDWs are not endangered, as required under the post-injection site care and site closure plan

Program/ Applicability	Lifespan of Permit	Financial Responsibility Requirements	Operational Requirements for Monitoring	Operational Requirements for Mitigation and/or Corrective Action	Post-Closure Requirements for Monitoring	Post-Closure Requirements for Mitigation and/or Corrective Action
		underground sources of drinking water.			USDWs.	

State Programs Regulating the Storage of CO_2 Apart from UIC

The state programs in Exhibit 80 represent state level programs in the EI that are applicable to underground storage of CO_2 and are not authorized by the UIC Program. Ten EI states have laws addressing permitting of storage, shown in Exhbit 5-23.

Of these ten EI states, West Virginia, Kentucky, Pennsylvania, Texas, and Montana have the five highest annual coal production rates, in order, with West Virginia producing the most. As shown in Exhibit 80, West Virginia, Kentucky, Texas, and Montana have enacted multiple laws to address permitting issues related to CCS. Although it is the 3rd highest producer of coal in the EI, Pennsylvania has not enacted similar laws.

Exhibit 80: Summary of the Eastern Interconnection State Programs Regulating the Storage of CO_2 Apart from UIC

Program/ Applicability	Lifespan of Permit	Financial Responsibility Requirements	Operational Requirements for Monitoring	Operational Requirements for Mitigation and/or Corrective Action	Post-Closure Requirements for Monitoring	Post-Closure Requirements for Mitigation and/or Corrective Action
Illinois						
Statute: 20 Ill. Comp. Stat. 1108/1-999, Clean Coal FutureGen for Illinois Act of 2011 - Applicable to the FutureGen Alliance for CO_2 storage in the Mount Simon Formation.	Minimum 10 years after cessation of injection until a certificate of completion is issued, barring permit amendments or until the site is transferred to the state.	Minimum level of financial assurances in the amount of $100,000,000 against potential losses from public liability actions, in the combination of insurance, CO_2 Storage Trust Fund balance, project assets, or cash or cash equivalents during the operations phase of the FutureGen Project, plus an additional 10-year period. State indemnification against any qualified loss from a public liability action to the extent that the loss is greater than $100,000,000 and is not covered by demonstrated financial assurance.	During injection, the operator must monitor CO_2 injection into the Mount Simon Formation in accordance with its permit.	The CO_2 Storage Trust Fund may be used to satisfy any qualified loss stemming from a public liability action to the extent that such loss is not otherwise covered by an insurance policy. Public liabilities include any civil legal liability arising out of or resulting from the storage, escape, release, or migration of the sequestered CO_2 that was injected by the operator. State indemnification against any qualified loss stemming from a public liability action to the extent that the loss is greater than $100,000,000 and is not covered by demonstrated financial assurance.	The CO_2 Storage Trust Fund may be used for post-closure monitoring.	Following proper site closure and the additional 10-year period, the operator transfers all rights, title, and interest, including any liabilities associated with the sequestered CO_2 to the State of Illinois. The CO_2 Storage Trust Fund may also be used for post-closure activities, including any civil legal liability arising out of or resulting from the storage, escape, release, or migration of the sequestered CO_2 that was injected by the operator.
Statute: 415 Ill. Comp. Stat. 5/13.7, Carbon dioxide	It is assumed that the permit is active until it	N/A	N/A	N/A	N/A	N/A

Program/ Applicability	Lifespan of Permit	Financial Responsibility Requirements	Operational Requirements for Monitoring	Operational Requirements for Mitigation and/or Corrective Action	Post-Closure Requirements for Monitoring	Post-Closure Requirements for Mitigation and/or Corrective Action
sequestration sites -Applicable to CO_2 storage sites.	is revoked by the state.					
Kansas						
Statute: K.S.A. 55-1636 et seq.. Carbon Dioxide Reduction Act Regulation: K.A.R. 82-3-1100 Carbon Dioxide (CO_2) Storage -Applicable to CO_2 storage sites.	Lifespan of operations, until the site has been granted a post- closure determination, the permit has been amended, or the site is transferred to the state.	Demonstrate and maintain financial responsibility to ensure proper operation and closure of the CO_2 storage facility.	Monitor CO_2 reservoir pressure and migration. Operator must have a plan for timely and permanent monitoring of soil, usable water, and the first porous zone immediately above the CO_2 reservoir. Monitoring plan must ensure the containment of the CO_2 within the reservoir and include monitoring vertical and horizontal CO_2 migration.	Report each leak, each potential leak, and any pressure changes or other monitoring data that indicate a loss of containment of injected CO_2 or associated fluids. Submit an action plan to repair the leak or regain containment, describing any corrective action, monitoring, or operational procedures that have been or will be taken.	Post-closure monitoring conducted by the state after site closure is paid for by fees from the operator deposited into the CO_2 Injection Well and Underground Storage Fund. Monitoring must cover the CO_2 plume and the lowest usable water zone.	Post-closure mitigation conducted by state after site closure paid for by fees from the operator deposited into the CO_2 Injection Well and Underground Storage Fund.
Kentucky						
Statute: KY Rev. Stat. Ann. § 353.800 et seq. Geologic Storage of Carbon Dioxide -Applicable to CO_2 storage sites.	Permitted until after cessation of injection and a required monitoring period, barring permit amendments or until the site is transferred to the state.	N/A	Program adheres to UIC Class V permitting, which requires performance of ground water monitoring and periodical submission monitoring results.	N/A	Upon completion of active injection and the plugging of the carbon injection wells, the storage operator shall monitor the storage facility for leakage and migration for the time period and by the methods required by	Liability for the stored CO_2 will remain with the storage operator until the facility is transferred to the state.

Program/ Applicability	Lifespan of Permit	Financial Responsibility Requirements	Operational Requirements for Monitoring	Operational Requirements for Mitigation and/or Corrective Action	Post-Closure Requirements for Monitoring	Post-Closure Requirements for Mitigation and/or Corrective Action
					the permit.	
Louisiana						
Statute: LA Rev. Stat. Ann. §§ 30:1101 – 30:1111, Louisiana Geologic Sequestration of Carbon Dioxide Act -Applicable to CO_2 storage sites.	A minimum 10 years after cessation of injection until a certificate of completion is issued, barring permit amendments or until the site is transferred to the state.	CO_2Storage Trust Fund, paid into based on a per-ton of CO_2 injected fee, can be used for operational inspecting, testing, and monitoring; remediation of mechanical problems; repairing mechanical leaks; plugging and abandoning wells.	Standards for the placement of monitoring equipment to correctly and accurately monitor and verify CO_2 injections. The CO_2Storage Trust Fund can be used for operational inspecting, testing, and monitoring.	The CO_2Storage Trust Fund can be used for operational remediation of mechanical problems and repairing mechanical leaks.	Post-closure inspecting, testing, and monitoring will be conducted by state after site closure are paid for by fees from the operator deposited into the CO_2 Geologic Storage Fund.	Post-closure remediation of mechanical problems and repairing mechanical leaks will be conducted by state after site closure are paid for by fees from the operator deposited into the CO_2 Geologic Storage Fund.
Mississippi						
Statute: Mississippi. Miss. Code Ann. § 53-11-1 et seq. Mississippi Geologic Sequestration of Carbon Dioxide Act (Likely to be implemented as state level UIC Class VI program after submission of primacy application to EPA) -Applicable to CO_2 storage sites.	Permit active for a minimum 2 years after certificate of completion barring permit amendments, at which point the financial assurance is released.	A per-ton fee will be assessed and collected into the CO_2 Storage Fund until it reaches or exceeds $ 2,500,000 per geologic sequestration facility. Financial assurance requirements are consistent with federal statutes, rules and regulations connected with Class VI underground injection control wells to be posted as a condition requirement	Operators must install monitoring equipment within a reasonable period of time which produces accurate readings. Program adheres to UIC Class VI permitting, which requires the operator prepare, maintain, and comply with a testing and monitoring plan to verify that the GS project is operating as permitted and is not endangering	The operator must complete any necessary remedial actions in order to be fully released from its financial assurance requirements. Program adheres to UIC Class VI permitting , which requires corrective action must be performed on all wells in the area of review that are determined to need corrective action, using methods designed to prevent	Monies in the CO_2 Storage Fund shall only be used, only if inadequate funds are available from responsible parties including financial assurance funds, for oversight of geologic storage facilities after cessation of injection at the facility and release of the facility's performance bond or other assurance of performance including, without limitation, matters	Monies in the CO_2 Storage Fund shall only be used if inadequate funds are available from responsible parties including financial assurance funds, for oversight of geologic storage facilities after cessation of injection at the facility and release of the facility's performance bond or other assurance of performance including, without limitation, matters

Program/ Applicability	Lifespan of Permit	Financial Responsibility Requirements	Operational Requirements for Monitoring	Operational Requirements for Mitigation and/or Corrective Action	Post-Closure Requirements for Monitoring	Post-Closure Requirements for Mitigation and/or Corrective Action
		for an approved. application by the storage operator.	underground sources of drinking water (USDWs).	the movement of fluid into or between USDWs, including use of materials compatible with the CO_2 stream, where appropriate.	with respect to closed facilities such as inspecting, testing and monitoring of the facility, including remaining surface facilities and wells. Program adheres to UIC Class VI permitting, which requires that following the cessation of injection, continued monitoring as specified in post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe. Monitoring must continue until the GS project no longer poses an endangerment to USDWs.	with respect to closed facilities such repairing mechanical problems associated with remaining wells and surface infrastructure; and repairing mechanical leaks at the facility. Program adheres to UIC Class VI permitting, which requires post-injection site care includes corrective action.
Montana						
Statute: Mont. Code Ann. § 82-11 Regulation by Board of Oil and Gas Conservation -Applicable to EOR operations being converted to CO_2 storage sites.	Permit for a minimum 50 years after cessation of injection (25-year period before a certificate of completion can be issued, and an additional 25-year	Demonstrate and maintain financial responsibility for a CO_2 injection well, GS reservoir, and CO_2 stored in a reservoir for operation and to	Operator must install and maintain monitoring equipment in the operation of CO_2 injection wells. The equipment will monitor and verify the GS reservoirs, in	Operator must mitigate any leaks, stop the leaking of CO_2, and address the impacts of the CO_2 leaks.	Prior the issuance of a certificate of completion and transfer of liability to state, 25-year period of monitoring and verification by the operator of wells and	Prior the issuance of a certificate of completion and transfer of liability to the state, 25-year period of monitoring and verification during which the

Program/ Applicability	Lifespan of Permit	Financial Responsibility Requirements	Operational Requirements for Monitoring	Operational Requirements for Mitigation and/or Corrective Action	Post-Closure Requirements for Monitoring	Post-Closure Requirements for Mitigation and/or Corrective Action
	monitoring and verification period) barring permit amendments or until the site is transferred to the state.	properly plug and reclaim injection wells. Operator must pay the state a fee on each ton of CO_2 injected for storage, which the state can use for long-term stewardship and liability after the site is transferred to the state. If the GS operator choses to indefinitely accept liability, the fees are refunded.	addition to characterizing the injection zone and any aquifers (above and below) the injection zone.		reservoir.	operator is responsible for mitigation of leaks and corrective action.

Program/ Applicability	Lifespan of Permit	Financial Responsibility Requirements	Operational Requirements for Monitoring	Operational Requirements for Mitigation and/or Corrective Action	Post-Closure Requirements for Monitoring	Post-Closure Requirements for Mitigation and/or Corrective Action
North Dakota						
Statute: N.D. Cent. Code § 38-22, Carbon Dioxide Underground Storage Regulations: N.D. Admin. Code 43-05, *Geologic Storage of Carbon Dioxide* -Applicable to EOR operations being converted to CO_2 storage sites and CO_2 storage sites.	Permit for a minimum 10 years after cessation of injection barring permit amendments or until the site is transferred to the state.	Payment of a fee on each ton of CO_2 injected for storage. Fee is deposited in CO_2 Storage Facility Administrative Fund and used for regulating storage facilities during their construction, operational, and pre-closure phases. Payment of an additional fee on each ton of CO_2 injected for storage. Fee must be deposited in the CO_2 Storage Facility Trust Fund for long-term monitoring and management of a closed storage facility.	Establish monitoring facilities and protocols to assess the location and migration of CO_2 injected.	N/A	Post-closure monitoring conducted by the state after site transfer is paid for by fees from the operator deposited into the CO_2 Storage Facility Trust Fund. Monitoring the storage facility is the state's responsibility until the federal government assumes responsibility for the long-term monitoring of storage facilities.	All rights, interests and responsibilities, associated with the stored CO_2 (including site management) conducted by state after site transfer are paid for by fees from the operator deposited into the CO_2 Storage Facility Trust Fund. Managing the storage facility is the state's responsibility until the federal government assumes responsibility for the long-term monitoring of storage facilities.
Oklahoma						
Statute: Okla. Stat. tit. 27A, §§ 3-5-101-3-5-106, *Oklahoma Carbon Capture and Geologic Sequestration Act* (Likely to be implemented as state level UIC Class VI program after submission of primacy	Permit required before operation of the CO_2 sequestration facility for the lifespan of operations barring permit amendments.	Authorizes the Corporation Commission and the Department of Environmental Quality to adopt, modify, repeal and enforce such rules,	Authorizes the Corporation Commission and the Department of Environmental Quality to adopt, modify, repeal and enforce such rules for	N/A	N/A	N/A

Program/ Applicability	Lifespan of Permit	Financial Responsibility Requirements	Operational Requirements for Monitoring	Operational Requirements for Mitigation and/or Corrective Action	Post-Closure Requirements for Monitoring	Post-Closure Requirements for Mitigation and/or Corrective Action
application to EPA) -Applicable to CO_2 storage sites.		including establishment of appropriate and sufficient fees, financial sureties or bonds, as may be necessary for the purpose of regulating the drilling of injection wells, the injection and withdrawal of CO_2, the operation of the sequestration facility, injection well plugging and abandonment, removal of buildings and equipment, and for any other purpose necessary.	monitoring sequestration facilities, as may be necessary for the purpose of regulating the drilling of injection wells, the injection and withdrawal of CO_2, the operation of the sequestration facility, injection well plugging and abandonment, removal of buildings and equipment, and for any other purpose necessary.			
Texas						
Statute: Tex. Water Code Ann. § 27, Injection Well Act Regulations: Geologic Storage and Associated Injection of Anthropogenic Carbon Dioxide (CO2), 16 Tex. Admin. Code §§ 5.201 – 5.208. -Applicable to CO_2 storage sites.	Permit for the lifespan of operations or until a certificate of closure is issued.	Payment of fee to be deposited in Anthropogenic CO_2 Storage Trust Fund to cover the Railroad Commission's costs for permitting, monitoring, and inspecting injection wells for GS storage and GS facilities and otherwise enforcing and implementing the GS and Associated Injection	Submit a monitoring, sampling, and testing plan for verifying that the GS facility is operating as permitted and that the injected fluids are confined to the injection zone. Continuously monitor injection pressure, rate, injected volumes, and pressure on the	Operator must perform corrective action on all wells and underground mines in the area of review that are determined to need corrective action. Operator must have an emergency and remedial response plan to address escape from the permitted injection	Operator must submit a post-injection storage facility care and closure plan that must include a description of the proposed post-injection monitoring location, methods, and frequency.	Operator must have an emergency and remedial response plan to address escape from the permitted injection interval or movement of the injection fluids or formation fluids that may cause an endangerment to underground sources of drinking water during the post-

Program/ Applicability	Lifespan of Permit	Financial Responsibility Requirements	Operational Requirements for Monitoring	Operational Requirements for Mitigation and/or Corrective Action	Post-Closure Requirements for Monitoring	Post-Closure Requirements for Mitigation and/or Corrective Action
		of Anthropogenic CO_2 program. Provide financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response through the post-injection care period. Upon issuance of a certificate of closure, the operator is released from financial assurance requirements.	annulus between tubing and long string casing to confirm that the injected fluids are confined to the injection zone.	interval or movement of the injection fluids or formation fluids that may cause an endangerment to underground sources of drinking water during construction, operation, and closure periods.		closure period.
West Virginia						
Statute: W. Va. Code § 22-11A. Carbon Dioxide Sequestration -Applicable to CO_2 storage sites.	Permit for the lifespan of operations barring permit amendments.	Operator must provide proof of financial responsibility to ensure that CO_2 sequestration sites and facilities will be properly constructed, operated and closed.	The operator must provide a monitoring plan to assess the migration of the injected CO_2 and to ensure the retention of the carbon CO_2 the sequestration site.	The operator must have a plan to mitigate the effects of injected CO_2.	The operator must provide a detailed plan for post-closure monitoring, verification, accounting, and maintenance.	The operator must provide a detailed plan for post-closure mitigation.

Beyond CCS permitting, there are several other state statutes, regulations, and policies that also address CCS. The following state programs in Exhibit 81 illustrate promulgated CCS policies for states that are major players in the coal industry (i.e., Illinois, Indiana, Kentucky, Ohio, and West Virginia). As of 2012, the following laws have been promulgated in these five states:

- One law incorporating CCS in EGU performance standards
- Two laws addressing certification of CO_2 offsets
- Four laws establishing financial incentives for CCS
- Four laws addressing requirements to include CCS in state Alternative Energy Portfolio Standards
- Six laws addressing other policy issues (e.g., state ownership of carbon capture facilities, state administered trust funds related to CCS operations, etc.)

Of the sample, West Virginia and Illinois had enacted the most policies for CCS. As previously discussed, West Virginia is the top EI state for annual coal production, and its legislative action to develop CCS policy creates a foundation for future development of the CCS industry in the state. In comparison Ohio has addressed CCS policy development only in terms of the DOE FutureGen project, and has not enacted laws regarding offsets or energy portfolio standards.

Exhibit 81: Examples of the Eastern Interconnection State Laws Addressing CCS Policy

Laws (Hyperlink to online source)	Requires Inclusion of CCS in State Alternative Energy Portfolio Standards	Incorporates CCS in EGU Performance Standards	Establishes Financial Incentives for CCS	Certification of CO_2 Offsets	Other Policy Issues
Illinois					
Statute: 20 Ill. Comp. Stat. 687/6-5 *Renewable Energy Resources and Coal Technology Development Assistance Charge*	N/A	N/A	N/A	N/A	Public utilities, electric cooperatives, and municipal utilities that deliver electricity or distribute natural gas in IL will charge customers a monthly Renewable Energy Resources and Coal Technology Development Assistance Charge. Half of the fees levied will be used for (1) capturing or sequestering carbon emissions produced by coal combustion and (2) supporting research on the capture and sequestration of carbon emissions produced by coal combustion.
Statute: 20 Ill. Comp. Stat. 3855/1-10, 1-58, 1-75, 1-80 *Illinois Power Agency Act*	Clean Coal Portfolio Standard requiring that electricity generated by clean coal represent at least 5% of each utility's total supply in 2015 and each year thereafter. By January 1, 2025, 25% of the electricity used in the State should be generated by cost-effective clean coal facilities. The percentage of CO_2 emissions a 'clean coal	N/A	Costs paid by the owner(s) associated with preparing a facility cost report for clean coal SNG facility (facility that uses a gasification process to produce substitute natural gas, that sequesters at least 90% of the total CO_2 emissions), including any capital costs associated with site preparation and remediation, sequestration of CO_2 emissions, and all interconnects and interfaces	N/A	Clean coal facilities must document the amount of carbon emissions captured and sequestered from the facility and report any amounts of carbon released from the site(s) where carbon is sequestered. The Illinois EPA may develop, finance, construct, or operate electric generation and co-generation facilities that use

Laws (Hyperlink to online source)	Requires Inclusion of CCS in State Alternative Energy Portfolio Standards	Incorporates CCS in EGU Performance Standards	Establishes Financial Incentives for CCS	Certification of CO_2 Offsets	Other Policy Issues
	facility' (facilities which sequester a specific portion of their emissions) must capture and sequester increases over time, starting at 50%, and reaching 90% after 2017.		required to operate the facility, may be paid or reimbursed. Reasonable amounts paid or due to be paid by the owner or owners of the clean coal SNG facility to third parties unrelated to the owner or owners to prepare the facility cost report will be reimbursed or paid up to $10 million through Coal Development Bonds.		indigenous coal or renewable resources, financed with bonds issued on behalf of the Agency. Any such facility that uses coal must be a clean coal facility and must be constructed in a location with geology suitable for carbon sequestration. The Agency may also develop, finance, construct, or operate a carbon sequestration facility. Establishes the Energy Efficiency Trust Fund that receives fees and penalties from CO_2 injection sites. The Department of Commerce and Economic Opportunity disburses the moneys in the Fund to benefit residential electric customers through projects that the Department has determined will promote energy efficiency in the State.
Statute: 220 Ill. Comp. Stat. 5/9-220, 5/16-115 *Public Utilities Act* Regulation: 83 Ill. Adm. Code 455 *Renewable Portfolio Standard and Clean*	Establishes State's goal that, by January 1, 2025, 25% of the electricity used in the State shall be generated by cost-effective clean coal facilities, which include facilities that captures and sequesters CO_2.	N/A	Sequestration costs approved by the Commerce Commission shall be recoverable by a clean coal SNG brownfield facility. 'Sequestration costs" means costs to be incurred by the clean coal SNG brownfield facility in accordance with its	N/A	If a clean coal SNG brownfield facility fails to demonstrate it captured and sequestered at least 85% of the total CO_2 emissions that the facility would otherwise emit, then the owner of the facility must pay a penalty of $ 20 per ton of excess

Laws (Hyperlink to online source)	Requires Inclusion of CCS in State Alternative Energy Portfolio Standards	Incorporates CCS in EGU Performance Standards	Establishes Financial Incentives for CCS	Certification of CO_2 Offsets	Other Policy Issues
Coal Standard for Alternative Retail Electric Suppliers and Utilities Operating Outside Their Service Areas			carbon capture and sequestration plan to capture CO_2, build, operate, and maintain a sequestration site in which CO_2 may be injected, build, operate, and maintain a CO_2 pipeline; and transport the CO_2 to the sequestration site or a pipeline.		carbon emissions up to $ 20,000,000, which shall be deposited into the Energy Efficiency Trust Fund. CO_2 emission credits equivalent to 50% of the amount of credits associated with the required sequestration of CO_2 from the facility must be permanently retired.
Statute: 20 Ill. Comp. Stat. 1108/1-999 *Clean Coal FutureGen for Illinois Act of 2011*	N/A	N/A	Offers tax exemptions to the FutureGen Alliance to make IL the most attractive location for FutureGen Project.	N/A	N/A
Indiana					
Statute: Ind. Code § 8-1-8.8 *Utility Generation and Clean Coal Technology*	N/A	N/A	N/A	N/A	It is in the public interest for the state to encourage the study, analysis, development, and life cycle management of nuclear energy production or generating facilities, as well as CO_2 capture, transportation, and storage facilities.
Statute: Ind. Code § 14-39 *Carbon Dioxide;*	N/A	N/A	N/A	N/A	Temporarily adds noncode provisions allowing the Indiana Department of Natural Resources to issue

Laws (Hyperlink to online source)	Requires Inclusion of CCS in State Alternative Energy Portfolio Standards	Incorporates CCS in EGU Performance Standards	Establishes Financial Incentives for CCS	Certification of CO_2 Offsets	Other Policy Issues
Eminent Domain for Transportation of Carbon Dioxide by Pipeline Regulation: 312 Ind. Admin. Code					certificates to construct and operate CO_2 transmission pipelines, which transfer CO_2 to carbon management applications, including sequestration.
Kentucky					
Statute: KY. Rev. Stat. Ann. § 154.27 *Incentives for Energy Independence Act* Regulation: 307 KY Admin. Regs. 1:040 *Application process for incentives for energy independence*	N/A	N/A	Creates a tax incentive for companies that construct, retrofit, or upgrade certain types of facilities that are designed in a "carbon capture ready manner," which means planning for or anticipating capture and compression of CO_2, as determined by the Kentucky Economic Development Finance Authority.	N/A	N/A
Ohio					
Statute: Ohio Rev. Code Ann. § 3706.101 *Futuregen Initiative Fund*	N/A	N/A	The FutureGen Initiative Fund consists of money appropriated to it and money from private donations, grants, gifts, bequests, and other sources. Money in the fund is used to make grants for the drilling of CCS test wells to assist the State's efforts to secure the U.S. DOE FutureGen initiative.	N/A	N/A

Laws (Hyperlink to online source)	Requires Inclusion of CCS in State Alternative Energy Portfolio Standards	Incorporates CCS in EGU Performance Standards	Establishes Financial Incentives for CCS	Certification of CO_2 Offsets	Other Policy Issues
West Virginia					
Statute: W. Va. Code § 18B-1B-12 *Research challenge*	N/A	N/A	N/A	N/A	The moneys deposited in the Research Challenge Fund will be used to fund coal research and development projects at institutions of higher education located in WV. Research topics include, but are not limited to, carbon sequestration and carbon technology research and development projects.
Statute: W. Va. Code § 22-5-19 *Net greenhouse gas inventory*	N/A	N/A	N/A	Authorizes the secretary of the department of health and human resources to establish a net greenhouse gas inventory, in which capture and sequestration of greenhouse gases from direct (geologic) sources will be included. The inventory will be used to determine whether WV is a net sink or emitter of greenhouse gas and whether greenhouse gas can be developed as an asset for economic development by establishing an inventory using reasonable estimates of current and future greenhouse gas emissions.	N/A

Laws (Hyperlink to online source)	Requires Inclusion of CCS in State Alternative Energy Portfolio Standards	Incorporates CCS in EGU Performance Standards	Establishes Financial Incentives for CCS	Certification of CO_2 Offsets	Other Policy Issues
Statute: W. Va. Code § 22-11A *Carbon Dioxide Sequestration*	It is in the public interest to advance the implementation of CO_2 capture and sequestration technologies into the state's energy portfolio.	If oil, natural gas, or coalbed methane operations to convert toCO_2 sequestration upon the cessation of oil or other mineral recovery operations, then the CO_2 sequestration facility and the CO_2 sequestration site shall be regulated pursuant to this law.	N/A	N/A	N/A
Statute: W. Va. Code § 24-2F *Alternative and Renewable Energy Portfolio Standard* Regulation: W. Va. Code R. § 150-34 *Rules Governing Alternative and Renewable Energy Portfolio Standard*	Qualified energy resources, including carbon capture and sequestration, will be awarded certified alternative and renewable energy resource credits to be used in meeting the Alternative and Renewable Energy Portfolio Standard.	N/A	N/A	The Public Service Commission may award credits to an electric utility for greenhouse gas emission reduction or offset projects, including electricity generated or purchased from an alternative energy resource facility, which includes alternative energy resources such as advanced coal technologies which incorporate CO_2 capture and sequestration technology.	N/A

The **Statutes and Regulations Appendix** below provides a more comprehensive list of CCS-related state laws in EI states[136], including policy and permitting laws.

5.5.2 Transport

As discussed above, CO_2 is most commonly transported via pipeline. Gaseous CO_2 is compressed to a pressure around 2,200 psi in order to increase its density and avoid two-phase flow regimes, thereby allowing cheaper, more efficient transport as a liquid. As such, there a number of design and operation-related standards and regulations that govern CO_2 transport in pipelines.

Operating Characteristics

The design of CO_2 pipelines is very similar to that of natural gas pipelines with the following exceptions, the higher pressures in CO_2 pipelines require thicker pipe, valves and other fittings require CO_2 resistant elastometers. Fracture arrestors are added every 1,000 feet in order to reduce fracture propagation stemming from the slower decompression properties of CO_2. Lastly, CO_2 pipelines move a supercritical fluid that is pumped at booster stations, while natural gas pipelines move a supercritical fluid that is compressed at booster stations.

CO_2 pipelines are typically restricted in the chemical composition of the fluids that can be legally transported through them. Exhibit 82 lists the typical quality specifications for U.S. CO_2 pipelines and the concerns they are aimed at addressing. The most important limit is the maximum amount of water allowed, since excessive water would react with the CO_2 to form carbolic acid and wear away the steel interior of the pipe. Additionally, since much of the CO_2 is used to aid enhanced oil recovery, the fluid's minimum miscible pressure in oil is limited in order to prevent complications in EOR. Limits on nitrogen, and hydrocarbons exist for these same reasons. It is important to note that a pipeline designed simply to transport CO_2 for storage would not necessarily be subject to these standards.

Exhibit 82: U.S. CO_2 Pipeline Quality Specifications

Constituent	Type of Limit	Value of Limit	Reason for Concern
CO_2	Minimum	95%	Minimum miscible pressure for EOR
Nitrogen	Maximum	4%	Minimum miscible pressure for EOR
Hydrocarbons	Maximum	5%	Minimum miscible pressure for EOR
Water	Maximum	30 lbs/MMcf	Corrosion
Oxygen	Maximum	10 ppm	Corrosion
H_2S	Maximum	10-200 ppm[137]	Safety

[136] Current as of July 12, 2012.

Glycol	Maximum	0.3 gal/MMcf	Operations
Temperature	Maximum	120 deg F	Materials

Source: IGNAA, Developing a Pipeline Infrastructure for CO_2 Capture and Storage: Issues and Challenges Pipeline Regulation

Existing CO_2 pipelines are subject to state, local and federal regulatory oversight. Minimum safety standards for pipelines transporting hazardous liquids (including CO_2) are set by the U.S. Department of Transportation's Office of Pipeline Safety (OPS). OPS regulates interstate pipelines and authorizes states to conduct intrastate pipeline regulation and enforcement.

While natural gas pipelines are subject to siting and rate regulation by the Federal Energy Regulatory Commission, there is no general federal certification of pipeline construction, rate regulation, or protection from competing CO_2 pipelines. However, pipelines which cross federal lands may be subject to access and rate conditions imposed by the Bureau of Land Management.

Starting and ending points for current CO_2 pipelines used for EOR are determined by the source and oil field location. Pipeline route selection or siting is often driven by environmental concerns, access availability, and costs. Pipelines usually follow existing utility easements and rights-of-ways wherever possible. State regulations for route review or approval vary. Some states have a regulatory process for certifying that the pipeline is in the public's interest in the event the pipeline company has to exercise the right of eminent domain for acquiring a portion of the route. For example, in Texas, a pipeline must be a common carrier to obtain eminent domain powers.[138]

According to the Interagency Report[139], regulations pertaining to the design, construction and safety of CO_2 pipelines have been put in place over the last 30 years, and are not considered as barriers to the widespread deployment of CCS technologies for the commercial projects planned by 2016, or for commercial efforts post 2020.[140]

Pipeline Rates

At present, CO_2 pipelines for EOR do not create or publish rate tariffs, and they are not mandated to do so. However, it is possible that if there was a rate dispute, a pipeline customer could try to bring the dispute in front of the Surface Transportation Board (STB). However, there are no known cases. Rate disputes could be rare given the current contractual setup of CO_2

[137] Higher levels of H2S may be allowed in pipelines going through sparsely populated areas and where the targeted EOR market for the CO_2 can accept higher H2S levels. For example, the pipeline from Dakota gasification plant to Weyburn has 1-2% H2S concentrations (10000-20000 ppm).

[138] INGAA, 2009. http://www.ingaa.org/File.aspx?id=8228

[139] *Report of the Interagency Task Force on Carbon Capture and Storage*, 2010, available at http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf.

[140] Sample state level programs applicable to CO_2 pipeline operators include the Illinois Carbon Dioxide Transportation and Sequestration Act (220 Ill. Comp. Stat. 75/5 – 7/99) and the Kentucky Electric Generation and Transmission Siting Act (KY Rev. Stat. Ann. § 353.800 et seq.).

transport for EOR. Pipeline laterals for EOR often go only to a specific oil field, thereby limiting the number of shippers on a particular pipeline. For third-party transportation, the contract terms are most likely agreed to before the pipeline is built, again reducing the potential for rate disputes.[141]

Current CO_2 pipelines do not have filed tariffs—in contrast, both oil pipelines and natural gas pipelines have tariff information available either on the FERC website or their own.

5.5.3 Capture

Under Subpart PP of the GHG reporting program of the Clean Air Act (CAA), facilities that capture CO_2 will be required to regularly monitor and report their emissions. Subpart PP also requires the reporting of CO_2 supplied to the economy and applies to all facilities with CO_2 production wells, facilities with production process units that capture and supply CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream to sequester or otherwise inject it underground, and to importers and exporters of bulk CO_2.

Furthermore, under the New Source Review Program of the CAA, any existing stationary source that undergoes major modification that results in a significant increase in emissions must install state of the art pollution control equipment. Since CCS equipment requires energy to capture and compress CO_2 , if the plant increases its energy production in order to meet this demand, and if that leads to a significant increase in emissions, it must install further controls in order to compensate for this increase.[142]

In addition, there are a number of other environmental impacts that need to be considered when CO_2 capture is added to a power plant: non-CO_2 air emissions, use and disposal of solvents and solid waste, and increased water use. Water use in power plants more than doubles with the addition of a capture plant, mostly due to increase in system cooling.[143] Increased fuel consumption to make up for the energy penalty implies that there will increase in solid wastes from a power plant with capture. There will also be waste associated with amines and other sorbents. It is expected that existing rules and regulations are sufficient to account for these additional environmental impacts resulting from capturing CO_2 in a power plant.

5.6 Other CCS Legal Issues

5.6.1 Long-term Liability

For CCS, there are two main types of long-term liabilities: (1) obligations to perform (e.g., conduct reclamation and monitoring requirements), commonly referred to as stewardship; and (2) obligations to compensate parties for various types and forms of legally compensable losses or damages, commonly referred to as compensatory liability. Geologic sequestration presents unique long-term concerns because the CO_2 is anticipated to remain stored indefinitely and

[141] INGAA, 2009. http://www.ingaa.org/File.aspx?id=8228
[142] *Ibid.*
[143] WRI, 2008. http://pdf.wri.org/ccs_guidelines.pdf

regulatory frameworks are often not designed to address liabilities over an indefinite duration. Issues related to long-term liability are described in Exhibit 83.

Exhibit 83: Overview of Long-Term Liability Issues

Issue	Description	Impact on CCS Development
Post-closure financial responsibility requirements	UIC Class VI requires operators/owners of underground GS facilities to demonstrate financial responsibility through post-injection site care.[144]	Potential cost barrier because financial responsibility required after operations have ceased and revenue stream has ended. [145]
Post-closure stewardship and compensatory liability	Owner/operators of CCS facilities may be required to satisfy stewardship obligations after injection has ceased during the post-closure period, and obligations for compensation to parties for legally compensable losses or damages.	Potential cost barrier because post-closure stewardship and compensatory liabilities are required after operations have ceased and revenue stream has ended. Additionally, unknown future costs for CCS owners/operators to address post-closure compensatory liability.
Federal liability transfer	The Safe Drinking Water Act (SDWA) does not provide authority to transfer liability to another entity from injection well owners/operators. Once all regulatory requirements have been met, the owner/operator will be released from liability. This is of concern in the CCS context due to the limited lifespan of owners/operators in relation to the indefinite timescale associated with CO_2 sequestration. [146]	Lack of responsible party after owners/operators released from obligations may cause public concern over who will pay for future unanticipated claims.
State liability transfer	Several states are developing CCS regulations to address liability transfer. [147]Example ways in which states have addressed liability transfer in CCS regulations include: • Certificate of completion, received after demonstration that the site is stable and has been closed, required	The way in which a state addresses liability transfer in CCS regulations may deter or encourage the level of CCS development in the state.

[144] 40 CFR § 146.85 Financial Responsibility
[145]*Report of the Interagency Task Force on Carbon Capture and Storage*, 2010, available at http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf.
[146]*Ibid.*
[147]*Ibid.*

	before the operator can transfer title and liability to the State. • States accept liability for CCS pilot projects within their borders. • Disclaimed state liability for long-term CO_2 storage sites.	
Potential for moral hazard associated with transfer of liability	Where there is a potential future transfer of liability, an owner/operator may be less careful, increasing the risk of an event because the party is partially insulated from being held fully liable for resulting harm and attendant damages.	Moral hazard could increase the risk of future incidents for which the government could be liable for mitigation and remediation.
Joint and several liability	Under joint and several liability, as in the CERCLA liability framework, it is possible that every entity that generates CO_2 and contributes it to a particular reservoir could be held liable for the entire cost of any liability that occurs, particularly if no other party is available to pay those costs.	Because of the indefinite duration of CO_2 sequestration, joint and several liability could create substantial financial obligations for responsible parties and a potential barrier to development. Stakeholders have noted that joint and several liability could hinder the development of commercial-scale GS projects and may not be appropriate, especially given that CO_2, in contrast to the substances regulated under CERCLA that are subject to joint and several liability, is not classified as a hazardous substance.

Different states have dealt with long-term CCS liabilities differently, including several states providing for the transfer of liability to the state. For example, Illinois' *Clean Coal FutureGen for Illinois Act of 2011* allows for transfer of liability to the state. Following operations, a ten-year post-closure phase, and permit compliance, Illinois accepts all rights, tittle, and interests to any liabilities associated with the sequestered CO_2.[148]

Similarly, in Kentucky, upon completion of injection and post-closure phase, liability may be transferred to the federal government, if a program agrees to accept it, or to the state as long as no federal program exists.[149] In Louisiana, following operations and a post-closure phase, liability is transferred to the state's Carbon Dioxide Geologic Storage Trust fund.[150]

[148] Clean Coal FutureGen for Illinois Act of 2011, 20 Ill. Comp. Stat. 1108/1-999.
[149] Geologic Storage of Carbon Dioxide, KY Rev. Stat. Ann. § 353.800 et seq.
[150] Louisiana Geologic Sequestration of Carbon Dioxide Act, LA Rev. Stat. Ann. § 30:1101-1111.

As part of these liability transfer programs, the length of post-closure phases varies. In Montana, under the 2009 regulation by the Board of Oil and Gas Conservation, the post-closure phase is a minimum of 25 years before a certificate of completion can be issued, and an additional 25-year monitoring and verification period before the title may be transferred to the state; in total, Montana requires a 50 year post-closure period before transfer.[151] In comparison, Illinois's program requires only a 10 year post-closure period, while Kentucky and Louisiana do not require post-closure care. Alternatively, Texas[152] and North Dakota[153] do not specify required lengths of a post-closure period, but allow for transfer after certain standards have been met.

5.6.2 Pore Space

Issues related to ownership of pore space and the appropriate rent for the use of pore space may create barriers to deployment of CCS technologies. Issues related to CCS and pore space are described in Exhibit 84.

Exhibit 84: Overview of Pore Space Issues

Issue	Description	Impact on CCS Development
Responsibility for third-party liability claims[154]	Different parties might own the surface estate, the subsurface mineral rights, the CO_2, and the subsurface voids and pore space into which CO_2 is placed or migrates.	Third-party liability claims for damages could impede the development of CCS due to legal uncertainties.
CO_2 storage sites crossing jurisdictional lines[155]	Multiple regulatory entities (e.g., local, state, or international authorities) may have authority over the pore space used by a single CO_2 storage site.	Multiple regulatory entities may have authority over the pore space used by a single CO_2 storage site creating uncertainty of jurisdictional authority. This uncertainty could potentially impede the development of CCS.

[151] Regulation by Board of Oil and Gas Conservation, Mont. Code Ann. § 82-11.
[152]Offshore Geologic Storage Of Carbon Dioxide, Tex. Health & Safety Code Ann. §§ 382.501 – 382.510.
[153] Carbon Dioxide Underground Storage ,N.D. Cent. Code § 38-22 .
[154] A. Bryan Endres. Geologic Carbon Sequestration: Balancing Efficiency Concerns And Public Interest In Property Rights Allocations, 2011, available at: http://illinoislawreview.org/wp-content/ilr-content/articles/2011/2/B_Endres.pdf.
[155] CCSReg Project. Policy Brief: Governing Access to and Use of Pore Space for Deep Geologic Sequestration, 2009, available at: http://www.ccsreg.org/pdf/PoreSpace_07132009.pdf.

Issue	Description	Impact on CCS Development
CO_2 storage sites crossing property of multiple surface owners[156]	The pore space in which CO_2 storage occurs can extend under property of different owners.	Pore space extending under property with multiple surface owners could create legal uncertainty regarding liability if sequestered CO_2 migrates across boundaries. This confusion could potentially impede the development of CCS because of uncertainty over obligations to surface owners.
GS could conflict with other uses of the subsurface, such as mineral extraction[157]	GS projects may be liable for "confusion of goods" claims if injected CO_2 intermingles with subsurface resources so that the resources can no longer be distinguished (e.g., injected CO_2 mixes with native gas where property rights have not been obtained).	Multiple ownership over the different parts of a piece of property (surface estate, the subsurface mineral rights, the CO_2 itself, and the subsurface voids and pore space) could lead to conflicts over land use amongst the different owners. This could potentially impede the development of CCS because of uncertainty over obligations to multiple owners of subsurface resources.

For example, the states of Kentucky, Montana, North Dakota and Wyoming have enacted pore space statutes that touch on issues such as pore space ownership, severability of pore space, access to pore space, and compulsory unitization.[158] All four states assign pore space ownership to the surface owner. In Kentucky, Montana, and Wyoming, pore space property ownership is severable from surface property ownership; North Dakota specifically excludes the severability of pore space. In Kentucky, Montana, and Wyoming, the storage operator has no right to enter the surface property to access pore space. Any surface property access must be agreed upon between the surface property and pore space owners. Again, since North Dakota does not permit the severability of pore space property, there are no statutes regarding surface property access. In all four states with pore space statutes, compulsory unitization of pore space is permitted, though the states differ on the percentage of pore space ownership that is required.

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[156] James Robert Zadick. The Public Pore Space: Enabling Carbon Capture and Sequestration by Reconceptualizing Subsurface Property Rights, 2011, available at: http://scholarship.law.wm.edu/cgi/viewcontent.cgi?article=1537&context=wmelpr.

[157] *Mark deFigueiredo, Property Interest and Liability of Geologic Carbon Dioxide Storage, Sept. 2005, available at _http://sequestration.mit.edu/pdf/deFigueiredo_Property_Interests.pdf.*

[158] Geologic Storage of Carbon Dioxide. KY Rev. Stat. Ann. § 353.800 et seq; Preservation of Property Rights. Mont. Code Ann. §82-11-180 (3).; Subsurface Pore Space Policy. N.D. Cent Code 47-31-01 et seq; Ownership of pore space underlying surfaces. Wyo. Stat. Ann. 34-1-152.

5.6.3 Offshore Development

For development of offshore CCS projects, the major issue of concern is the lack of a regulatory framework applicable to operations on the outer continental shelf (OCS). Issues related to the development of offshore CCS projects are described in Exhibit 85.

Exhibit 85: Overview of Offshore Issues

Issue	Description	Impact on CCS Development
OCS federal jurisdiction	OCS development falls under the jurisdiction of the Department of the Interior (DOI). The DOI has noted that the U.S. Bureau of Land Management has the authority to issue leases, permits, and easements to accommodate a wide range of CCS development activity, including surface and subsurface rights-of-way and leases for subsurface storage on federal land. However, the DOI's 2009 "Framework for Geological Carbon Sequestration on Public Land," makes no mention of offshore CCS development. [159]	Lack of regulatory framework for OCS development may deter development of OCS projects.
OCS state jurisdiction	Varying regulatory authorities for offshore CCS project development • On the OCS, federal jurisdiction is 3 to 200 nautical miles from the coast (state jurisdiction from the coast to 3 nautical miles) • Submerged lands in the Gulf of Mexico are administered by the Texas General Land Office, which has unique offshore sovereignty, beginning at the coast and extending out 10.3 nautical miles.	Different regulations may deter or encourage CCS development depending on the regulatory entity with authority for regulating the project.

State level regulations in Texas directly impact the issue of development of offshore CCS operations. Specifically, beginning in 2009, Texas began establishing a framework for offshore CCS projects. Projects on General Land Office (GLO) land (i.e., State submerged land) must meet both the Texas Commission on Environmental Quality and Railroad Commission (RRC)

[159] U.S. Department of Interior, *Report to Congress: Framework for Geological Carbon Sequestration on Public Land*, 2009, available at http://groundwork.iogcc.org/sites/default/files/Framework%20for%20Geological%20Storage.pdf.

regulations as well as be consistent with EPA regulations.[160] The GLO is authorized to promulgate regulations for GS on GLO submerged lands and create rules adopting standards for the location, construction, maintenance, monitoring, and operation of an offshore, deep subsurface CO_2 geologic storage repository.[161] While these regulations have not yet been promulgated, the statute does establish that the state has long-term liability for stored CO_2.[162]

5.6.4 CO_2 as a Hazardous Substance or Waste

An issue of concern for development of CCS projects is whether CO_2 will be designated as a hazardous substance. This can be of particular importance for both transport and storage. However, it can also impact the capture process, as some of the incidental substances can be left in the CO_2 stream, if they are not deemed hazardous. Issues related to the designation of CO_2 as a hazardous substance or waste at the Federal level are described in Exhibit 86.

Exhibit 86: Overview of CO_2 as a Hazardous Substance or Waste

Issue	Description	Impact on CCS Development
CO_2 potentially listed as a RCRA hazardous waste	RCRA Subtitle C establishes a ‘‘cradle to grave’’ regulatory scheme for certain hazardous solid wastes. While there may be components of a CO_2 stream that could potentially be considered hazardous, the CO_2 stream itself is not listed as a RCRA hazardous waste. Hence, there is some uncertainty as to the applicability of RCRA subtitle C requirements for CO_2 streams. If the captured CO_2 stream contains hazardous constituents, such that it might meet the definition of a RCRA hazardous waste, EPA has proposed to conditionally exclude that CO_2 stream from hazardous waste regulations if conditions in the proposal are met: compliance with applicable transportation and related pipeline requirements, injection into UIC Class VI wells, and prohibition on mixing	Various stakeholders and studies have characterized potential RCRA applicability as a possible barrier to CCS deployment due to its complex regulatory regime. Characterization of a CO_2 stream as hazardous waste would make the RCRA waste management scheme applicable to the generation, transportation, treatment, sequestration, and/or disposal of the CO_2 stream. This determination would mean that underground injection and sequestration of such a CO_2 stream would need to meet the requirements for Class I hazardous waste wells under the SDWA UIC Program rather than for Class VI GS wells.[164]

[160] The Texas General Land Office, Railroad Commission of Texas and Texas Commission on Environmental Quality, Injection and Geologic Storage Regulation of Anthropogenic Carbon Dioxide, 2012, available at http://www.rrc.state.tx.us/forms/reports/notices/SB1387-FinalReport.pdf

[161] H.B. 1796, 81st Legislature Regular Session (TX 2009).

[162] Offshore Geologic Storage Of Carbon Dioxide, Tex. Health & Safety Code Ann. §§ 382.501 – 382.510

Issue	Description	Impact on CCS Development
	hazardous waste with the CO_2 stream.[163]	
CO_2 potentially listed as a CERCLA hazardous Substance	CO_2 is not listed as a hazardous substance under CERCLA; however, the CO_2 stream may contain a listed hazardous substance or may mobilize substances in the subsurface that could react with ground water to produce hazardous substances.[165] If CO_2 was listed as a CERCLA hazardous substance, CO_2 sequestration projects would likely fall within the definition of a "facility," a site where a hazardous substance is deposited or stored, and owners and operators of CO_2 sequestration projects could qualify as CERCLA responsible persons.	Various stakeholder studies have characterized potential CERCLA applicability as a barrier to CCS deployment. However, even if CO_2 was listed as a CERCLA hazardous substance, if injected CO_2 streams fall under the SDWA UIC Program, EPA may find that owners/operators are exempt from CERCLA liability where the injection qualifies as a "Federally Permitted Release" (FPR). CERCLA exempts from liability certain FPRs, which would include the permitted CO_2 stream, as long as the stream is injected in accordance with the Class VI permit requirements.

Montana is the only identified example that has addressed the issue of classification of CO_2 as a hazardous substance or waste. Specifically, the regulations implementing Montana's Water Quality Statute explicitly states that CO_2 within a GS reservoir is not a pollutant, a nuisance, or a hazardous substance.[166]

5.7 Statutes and Regulations Appendix

Statutes and Regulations Related to CCS (Hyperlink to online source)
Florida
Statute: 259.105 F.S., *The Florida Forever Act* Regulation: 18-24.0022, F.A.C., *Florida Forever Goals and Numeric Performance Measures*

[164] *Report of the Interagency Task Force on Carbon Capture and Storage*, 2010, available at http://www.epa.gov/climatechange /Downloads/ccs/CCS-Task-Force-Report-2010.pdf.
[163] Bureau of Offshore Energy Management, *Analysis of the Costs and Benefits of CO_2 Sequestration on the U.S. Outer Continental Shelf,* 2012, available at http://boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Energy_Economics /External Studies/OCS%20Sequestration%20Report.pdf.
[165] U.S. Environmental Protection Agency, *Frequent Questions about Carbon Dioxide (CO_2) Streams Being Sequestered*, available at *http://www.epa.gov/wastes/nonhaz/industrial/geo-sequester/faqs.htm*.
[166] Regulation by Board of Oil and Gas Conservation, Mont. Code Ann. § 82-11.

Statute: 366.91 - 366.92 F.S., *Public Utilities, Renewable Energy*
Statute: 288.9606 F.S., *Commercial Development and Capital Improvements*
Statute: 373.236 F.S., *Permitting of Consumptive Uses of Water* Regulation: 40B-2.321, 40B-2.341, F.A.C., *Suwannee River Water Management District Permitting of Water Use*
Statute: 403.973 F.S., *Expedited Permitting; amendments to comprehensive plans*
Illinois
Statute: 20 Ill. Comp. Stat. 687/6-5, *Renewable Energy Resources and Coal Technology Development Assistance Charge*
Statute: 20 Ill. Comp. Stat. 3855/1-10, 1-58, 1-75, 1-80, *Illinois Power Agency Act*
Statute: 220 Ill. Comp. Stat. 5/9-220, 5/16-115, *Public Utilities Act* Regulation: 83 Ill. Adm. Code 455, *Renewable Portfolio Standard and Clean Coal Standard for Alternative Retail Electric Suppliers and Utilities Operating Outside Their Service Areas*
Statute: 20 Ill. Comp. Stat. 1108/1-999, *Clean Coal FutureGen for Illinois Act of 2011*
Statute: 220 Ill. Comp. Stat. 75/5-7/99, *Carbon Dioxide Transportation and Sequestration Act*
Statute: 415 Ill. Comp. Stat. 5/13.7, *Carbon dioxide sequestration sites*
Indiana
Statute: Ind. Code § 8-1-8.8, *Utility Generation and Clean Coal Technology*
Statute: Ind. Code § 14-39, *Carbon Dioxide; Eminent Domain for Transportation of Carbon Dioxide by Pipeline* Regulation: 312 Ind. Admin. Code, (Emergency Rule) [No title identified]
Iowa
Statute: Iowa Code § 476.53, *Electric generating and transmission facilities*
Regulation: Iowa Admin. Code r. 401.6, *Eligibility criteria for financial assistance*
Kansas
Statute: K.S.A. 55-1636 et seq., *Carbon Dioxide Reduction Act* Regulation: K.A.R. 82-3-1100, *Carbon Dioxide (CO_2) Storage*
Statute: K.S.A. 79-233, *Property exempt from taxation; carbon dioxide capture, sequestration or utilization property*
Statute: K.S.A. 79-32,256, *Carbon dioxide capture, sequestration or utilization machinery or equipment; accelerated depreciation, deduction*

Kentucky
Statute: KY. Rev. Stat. Ann. § 154.27, *Incentives for Energy Independence Act* Regulation: 307 KY Admin. Regs. 1:040, *Application process for incentives for energy independence*
Statute: KY H.B. 1, Section 52, *An Act relating to the advancement of energy policy, science, technology, and innovation in the Commonwealth, making an appropriation therefore and declaring an emergency*
Statute: KY Rev. Stat. Ann. § 278.700 et seq., *Electric Generation and Transmission Siting*
Statute: KY Rev. Stat. Ann. § 353.800 et seq., *Geologic Storage of Carbon Dioxide*
Louisiana
Statute: LA Rev. Stat. Ann. §§ 30:1101 – 30:1111, *Louisiana Geologic Sequestration of Carbon Dioxide Act*
Statute: LA Rev. Stat. Ann. § 19:2, *Expropriation by state or certain corporations and limited liability companies*
Maine
Statute: ME Rev. Stat. Ann. tit. 38, § 585-K, *Greenhouse gas emission standards; moratorium*
Massachusetts
Statute: Mass. Gen. Laws ch. 25A § 11F1/2, *Alternative Energy Portfolio*
Regulation: 310 Mass. Code Regs. 7.70, *Massachusetts CO_2 Budget Trading Program*
Michigan
Statute: Mich. Comp. Laws § 460.1003 et seq., *Clean, Renewable, and Energy Efficiency Energy Act*
Minnesota
Statute: M.S. 216H, *Greenhouse Gas Emissions*
Statute: M.S. 216B.1694, *Innovative Energy Project*
Mississippi
Statute: Miss. Code Ann. § 53-11-1 et seq., *Mississippi Geologic Sequestration of Carbon Dioxide Act*
Statute: Miss. Code Ann. § 27-65-19, *Public utilities* Regulation: Code Miss. Rules § 35.IV.6.01, *Sales and Use Tax: Utilities*
Montana
Statute: Mont. Code Ann. § 69-8-421, *Approval of electricity supply resources*

Regulation: Mont. Code Ann. § 15-24-3111, *Energy production or development -- tax abatement -- eligibility* Regulation: Mont. Admin. R. 17.80.202, 17.80.204, *Tax Abatement and Classification* Regulation: Mont. Admin. R. 42.4.4114, *Energy production or development - property tax abatement eligibility for new investment in the conversion, transport, manufacture, research, and development of renewable energy, clean coal energy, and carbon dioxide equipment and facilities*
Statute: Mont. Code Ann. § 75-5, *Water Quality*
Statute: Mont. Code Ann. § 82-10-402, *Inventory of abandoned wells and seismic operations -- reclamation procedures*
Statute: Mont. Code Ann. § 82-11, *Regulation by Board of Oil and Gas Conservation*
New York
Statute: N.Y. Tax Law § 16, *QEZE Tax Reduction Credit* Regulation: N.Y. Comp. Codes R. & Regs tit. 5, §§ 10.2 – 16.6, *Economic Development Zones: Definitions and Zone Designation Application Process*
North Dakota
Statute: N.D. Cent. Code § 38-22, *Carbon Dioxide Underground Storage* Regulation: N.D. Admin. Code 43-05, *Geologic Storage of Carbon Dioxide*
Ohio
Statute: Ohio Rev. Code Ann. § 3706.101, Futuregen Initiative Fund
Statute: Ohio Rev. Code Ann. § 5515.01, *Permits granted to use or occupy portion of road or highway*
Oklahoma
Statute: Okla. Stat. tit. 27A, §§ 3-5-101-3-5-106, *Oklahoma Carbon Capture and Geologic Sequestration Act*
Statute: Okla. Stat. tit. 27A, §§ 3-4-101- 3-4-105, *Oklahoma Carbon Sequestration Enhancement Act* Regulation: Okla. Admin. Code § 155:30, *Oklahoma Conservation Commission – Oklahoma Carbon Sequestration Certification Program – Geologic Sequestration*
Pennsylvania
Statute: 71 PA. Cons. Stat. § 1361.3, *Report on potential climate change impact and economic opportunities for this Commonwealth*
Statute: 66 PA. Cons. Stat. § 2815, *Carbon dioxide sequestration network*

Statute: 73 PA. Cons. Stat. § 1650.3, *Chapter 18H: Biodiesel content in diesel fuel sold for on-road use*
South Dakota
Statute: S.D. Codified Laws §§ 49-41B-24, *Energy Conversion And Transmission Facilities*
Tennessee
Statute: Tenn. Code Ann. § 67-6-232, *Credit for establishing a qualified facility to support an emerging industry or a major cultural attraction*
Texas
Statute: Tex. Health & Safety Code Ann. § 382.0565, *Clean Coal Project Permitting Procedure* Regulation: 30 Tex. Admin. Code § 116, *Permits For Specific Designated Facilities*
Statute: Tex. Water Code Ann. § 5.558, *Clean Coal Project Permitting* Regulation: 30 Tex. Admin. Code § 91, *Alternative Public Notice and Public Participation Requirements for Specific Designated Facilities; Purpose and Applicability*
Statute: Tex. Nat. Res. Code Ann. § 119, *Ownership Of Carbon Dioxide Captured By Clean Coal Project*
Statute: Tex. Tax Code Ann. § 11.31, *Pollution Control Property*
Statute: Tex. Tax Code Ann. § 26.045, *Rollback Relief For Pollution Control Requirements*
Statute: Tex, Tax Code Ann. § 202.0545, *Tax Exemption For Enhanced Recovery Projects Using Anthropogenic Carbon Dioxide* Regulation: 16 Tex. Admin. Code § 3.50, *Enhanced Oil Recovery Projects--Approval and Certification for Tax Incentive* Regulation: 34 Tex. Admin. Code § 3.37, *Enhanced Oil Recovery Projects*
Statute: 34 Tex. Admin. Code § 3.326, *Carbon Dioxide Capture and Sequestration*
Statute: Tex. Water Code Ann. § 27, *Injection Well Act* Regulation: 16 Tex. Admin. Code §§ 5.201 – 5.208, *Geologic Storage And Associated Injection Of Anthropogenic Carbon Dioxide (CO_2)* Regulation: 16 Tex. Admin. Code §§ 5.301 – 5.308, *Certification Of Geologic Storage Of Anthropogenic Carbon Dioxide (CO_2) Incidental To Enhanced Recovery Of Oil, Gas, Or Geothermal Resources* Regulation: 16 Tex, Admin. Code § 3.30, *Memorandum of Understanding Between the Railroad Commission of Texas (RRC)and the Texas Commission on Environmental Quality (TCEQ)*

Statute: Tex. Tax Code Ann. § 151.334, *Components Of Tangible Personal Property Used In Connection With Sequestration Of Carbon Dioxide*
Statute: Tex. Nat. Res. Code Ann. §§ 91.801-91.802, *Authorization For Multiple Or Alternative Uses Of Wells*
Statute: Tex. Nat. Res. Code Ann. § 120, *Verification, Monitoring, And Certification Of Clean Energy Project*
Statute: Tex. Gov't Code Ann. § 490, *Funding For Emerging Technology*
Statute: Tex. Health & Safety Code Ann. §§ 382.501 – 382.510, *Offshore Geologic Storage Of Carbon Dioxide*
Regulation: 34 Tex. Admin. Code § 9.1051, *Limitation on Appraised Value and Tax Credits on Certain Qualified Property*
Statute: Tex. Nat. Res. Code Ann. § 121, *Ownership And Stewardship Of Anthropogenic Carbon Dioxide*
Virginia
Statute: VA Code Ann. 56-585.1, *Generation, distribution, and transmission rates after capped rates terminate or expire* Regulation: 20 VA Admin. Code 5-201, *Rules Governing Utility Rate Applications and Annual Informational Filings*
West Virginia
Statute: W. Va. Code § 18B-1B-12, *Research challenge*
Statute: W. Va. Code § 22-5-19, *Net greenhouse gas inventory*
Statute: W. Va. Code § 22-11A, *Carbon Dioxide Sequestration*
Statute: W. Va. Code § 24-2F, *Alternative and Renewable Energy Portfolio Standard* Regulation: W. Va. Code R. § 150-34, *Rules Governing Alternative and Renewable Energy Portfolio Standard*
Wisconsin
Statute: Wis. Stat. § 285.78, *Registration of early emissions reductions* Regulation: Wis. Admin. Code NR § 437, *Voluntary Emission Reduction Registry*

Task 6: Risk and Liabilities

In addition to subjects discussed in previous tasks, a number of other factors also influence the current state and future development of coal-fired capacity in the Eastern Interconnection. Task 6 focuses on various aspects that can potentially encourage or discourage future development of new coal-fired generating resources. This task covers the following items[167]:

1. Comprehensive summary table including various incentives and disincentives for coal-fired capacity and coal mining industry
2. The potential effects of natural gas from shale and other resources on the development of coal-fired generation throughout the Eastern Interconnection
3. Examination of the role of ISOs/RTOs in planning the development of new generating resources

6.1 State Level Statutes and Regulations

A separate Excel spreadsheet was provided to EISPC with a comprehensive list of state-by-state statutes and regulations concerning coal-fired capacity and the coal mining industry. The spreadsheet also includes a list of state policies regarding construction work in progress (CWIP). In addition to existing statutes and regulations that inhibit or encourage the development of new coal-fired generating resources, Minnesota and New Jersey have passed moratoriums that would impede the development of any new coal-fired facilities.

To comply with existing and upcoming regulations, environmental concerns will have to addressed by installing retrofits and potential inclusion of CCS technologies. In order to achieve commercial availability of CCS technologies for power plant projects, besides R&D and demonstration efforts to lower costs and technology risks, state level statutes and regulations can also play an important role in advancing the cause. Incentives that encourage and subsidize installation of CCS technologies would assist the development of advanced coal-fired plants, but this process is also subject to the economics of natural gas prices. The majority of the regulations and statues regarding CCS incentives were established prior to the natural gas glut in 2008, while natural gas prices were high. Therefore, incentives that encourage power plants to incorporate CCS would be most effective on coal-fired plants, if natural gas prices gradually increase to a relatively high level.

In states such as Florida, Michigan, and West Virginia, renewable portfolio standards issued by each state indicate that the definition of "renewable enegy" has been expanded to include an option for CCS technologies. In this way, incentives designed for renewable energy resources will also impact coal-fired plants with CCS technologies. Some states also provide financial incentives (i.e. tax credits, tax abatements, and grants) for CCS projects. For instance, Montana provides property tax abatements for new investments in CCS equipment and facilities. Property

[167] The following subjects included under Task 6 in the contract are discussed in Task 5 instead: legal and regulatory issues involved with permitting CO_2 storage and pipelines, economic and engineering feasibility/requirements of CO_2 pipelines under a variety of scenarios for locations of potential pipelines, and state-by-state treatment of the legal and regulatory issues related to carbon storage.

tax abatements could equal up to 50% of the taxable value for facilities and equipment involved in capturing.[168] Illinois Finance Authority made an authorization to provide dinancial assistance to energy generating facilities, which provides up to $300 million in bon fonds for new gasification facilities with ca[acity greater than 400 MW that supports coal gasification or IGCC projects.[169] Mississippi sets the sales tax associated with the sales of CO_2 for geological sequestrationat 1.5% as opposed to 7% of sales tax assessed on businesses selling to consumers traditional forms of electricity, current, power, potable water, steam, coal, natural gas, liquefied petroleum gas or other fuel.[170] These financial incentives help encourage investments in CCS related power projects.

Incentives for the coal mining industry often goes hand in hand with incentives targeting coal-fired capacity, particularly in states where coal-mining still plays an important role in suataining the economy. Alaska, Illinois, Maryland, Ohio, Oklahoma, and Virginia all provide tax credits of various amounts on each ton of coal mined, produced, or extracted within the state for the purpose of electricity generation. These incentives issued by individual states help sustain the coal mining industry, while securing fuel sources for coal-fired power generating resources.

The spreadsheet provided to EISPC included state-by-state statutes and regulations concerning coal-fired capacity and the coal mining sector. These statutes and regulations represent potential opportunities, though imited, in helping encourage future development of new coal-fired units.

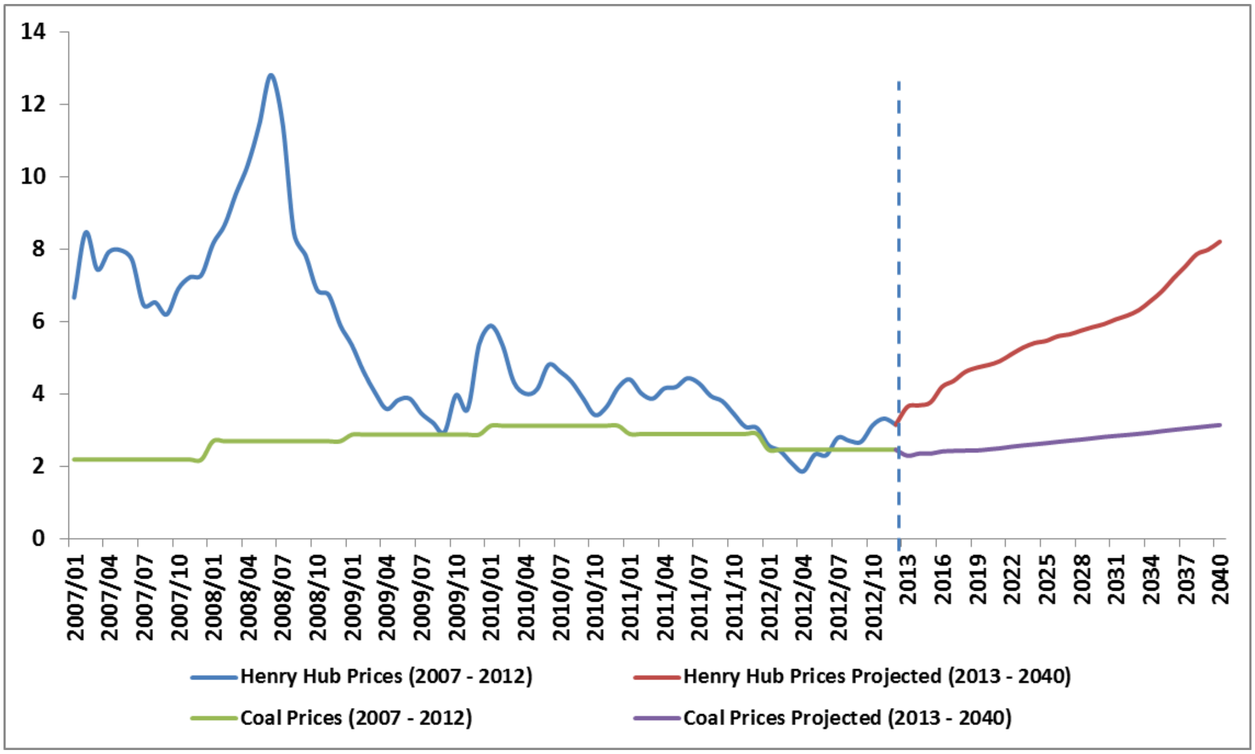
6.2 Impact of Shale Gas on Coal Development

Construction of new coal-fired power plants and dispatch from existing coal plants face a major challenge from the new market reality of low natural gas prices. Regulations and projected low gas prices together have been the main economic impetus for retirements and decreasing dispatch from coal plants. The combination of these two factors can fundamentally impact the role of coal-fired generation going forward.

Natural gas prices have decreased since the peak in 2008, with recent Henry Hub prices dipping below $2.50/MMBtu before recovering to the $4/MMBtu range. Exhibit 87 shows the sharp decrease in natural gas spot prices since 2007, and the EIA's forecast of a gradual recovery of gas prices in the long term. On the other hand, while natural gas prices experience sharp increases and decreases, stable coal prices are projected to remain basically flat in the future. And while the expected rise in natural gas prices compared to coal will benefit existing coal generation, its relative cost will continue to make it difficult to finance new coal capacity.

[168] Mont. Code Ann. §15-24-31 Property Related Renewable Energy, New Energy Technology, and Clean Coal.
[169] 20 Ill. Comp. Stat. §605-332.
[170] Code Miss. Rules §35.IV.6.01 Sales and Use Tax: Utilities.

Exhibit 87: Historical and Forecasted Gas and Coal Prices (2010$/MMBtu)



Source: EIA AEO2013 Early Release; EIA Annual Energy Review

6.2.1 State of Natural Gas Development

According to an International Energy Agency (IEA) report entitled "Are We Entering a Golden Age of Gas?", the world's proven reserves of natural gas at the beginning of 2010 was approximately twice the amount of natural gas produced to date, and equivalent to more than 50 years of production at current rates worldwide.[171] The availability and commercialization of advanced extraction technology is the main element enabling the expansion of natural gas reserves. In North America, there has been significant gas production from shale formation for many decades, primarily from vertical wells in the Appalachian Devonian Shale. However, the recent rapid growth in shale gas production has been the result of the combination of horizontal drilling and multi-stage hydraulic fracturing. This combined technology application has been used primarily over the past 15 to 20 years, beginning with early work in the Barnett Shale of North Texas. While hydraulic fracturing has been used by the industry in North America since the 1950s, horizontal drilling is a more recent technology. In horizontal drilling, a vertical well section is drilled to a point several hundred feet above the shale layer. A specialized directional drilling unit then proceeds to angle the borehole to intersect the shale formation horizontally along an interval ranging from several thousand to over 10,000 feet. Once the horizontal section

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[171] IEA, Are We Entering a Golden Age of Gas?
http://www.worldenergyoutlook.org/media/weowebsite/2011/WEO2011_GoldenAgeofGasReport.pdf

is drilled, anywhere from 10 to 20 stages are stimulated using high pressure fracturing fluid, which is almost all water, with additives and a propping agent such as sand.

According to the EIA, proved reserves of natural gas in the lower 48 states have increased from 200.8 trillion cubic feet (TCF) in 2007 to 317.6 TCF in 2011, at an annual average rate of 12.1%.[172] Production and consumption of natural gas grew at approximately 3.7% and 1.4% respectively. A large part of the increased production is from shale based natural gas, and with production from shale plays experiencing the largest increase: from 2.0 TCF in 2007 to 8.5 TCF in 2011, shale gas accounted for 30% of total production in 2011 compared to a mere 8% in 2007.[173]

Exhibit 88: Natural Gas Production and Consumption Data (2007 – 2011)

		2007	2008	2009	2010	2011	Growth Rate
Natural Gas Proved Reserves	**trillion cubic feet**	200.8	237.7	255.0	283.9	317.6	12.1%
Natural Gas Production	**trillion cubic feet**	24.7	25.6	26.1	28.8	28.5	3.7%
Natural Gas Production from Shale	**trillion cubic feet**	2.0	2.9	4.0	5.8	8.5	43.6%
Natural Gas Consumption	**trillion cubic feet**	23.1	23.3	22.9	24.1	24.4	1.4%
% of Shale Production in Total Gas Production	**%**	8.1	11.2	15.2	20.2	29.8	

Source: EIA, U.S. Crude Oil, Natural Gas, and NG Liquids Proved Reserves, August 2012; EIA, Natural Gas Annual, 2011

As indicated on the map of shale plays in the United States, the regions with the majority of technically recoverable shale gas resources are the Northeast, Gulf Coat, and Southwest. Within these three regions, the largest shale play is the Marcellus in the Northeast, which contributed to 55% of total recoverable reserves in the United States; the Northeast as a whole contributed to 63% of the total recoverable reserves.[174] Both the Northeast and Gulf Coast are within the borders of the EI, and gas producing areas in the U.S. Southwest also transports natural gas into the EI regions such as New York, for instance through the Transcontinental Gas Pipeline Company System. The abundance in recoverable reserves is also reflected by a sharp increase in shale gas production within the last few years, and a commensurate drop in natural gas prices.

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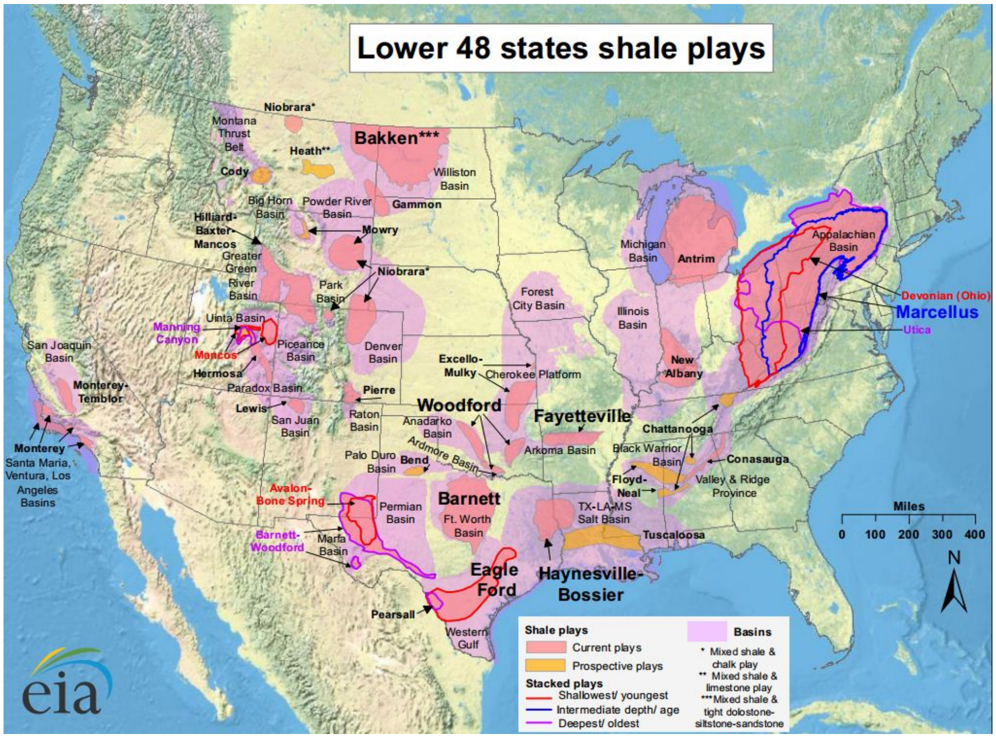
[172] U.S. Crude Oil, Natural Gas, and NG Liquids Proved Reserves. http://www.eia.gov/naturalgas/crudeoilreserves/

[173] Data is extracted from the EIA's U.S. Crude Oil, Natural Gas, and NG Liquids Proved Reserves report from August 2012, in which the latest data is from 2011.

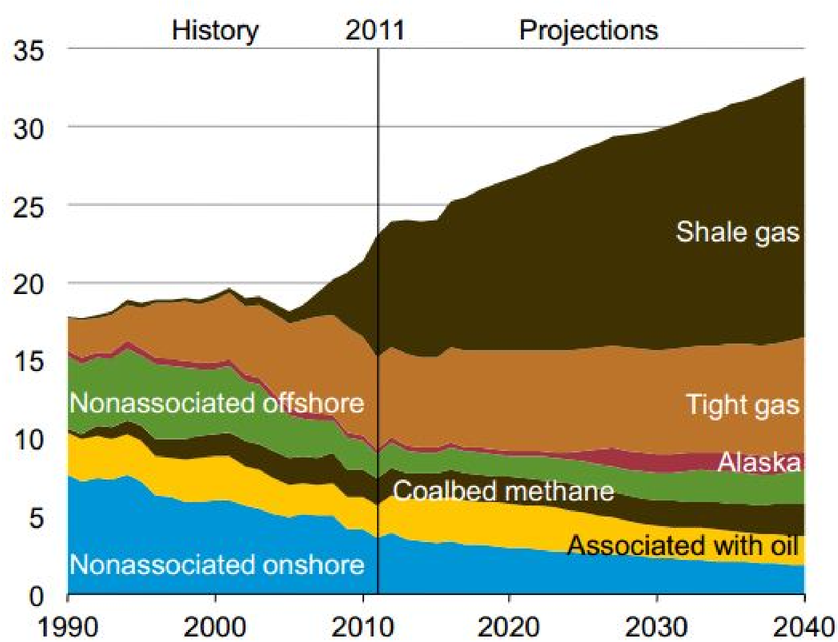
[174] EIA, Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays, July 2011. http://www.eia.gov/analysis/studies/usshalegas/pdf/usshaleplays.pdf

Exhibit 89: Lower 48 States' Shale Plays



Source: EIA, Natural Gas, United States Shale Gas Maps, Lower 48 States Shale Plays

Exhibit 90: U.S. Dry Natural Gas Production by Source 1990 – 2040 (TCF)



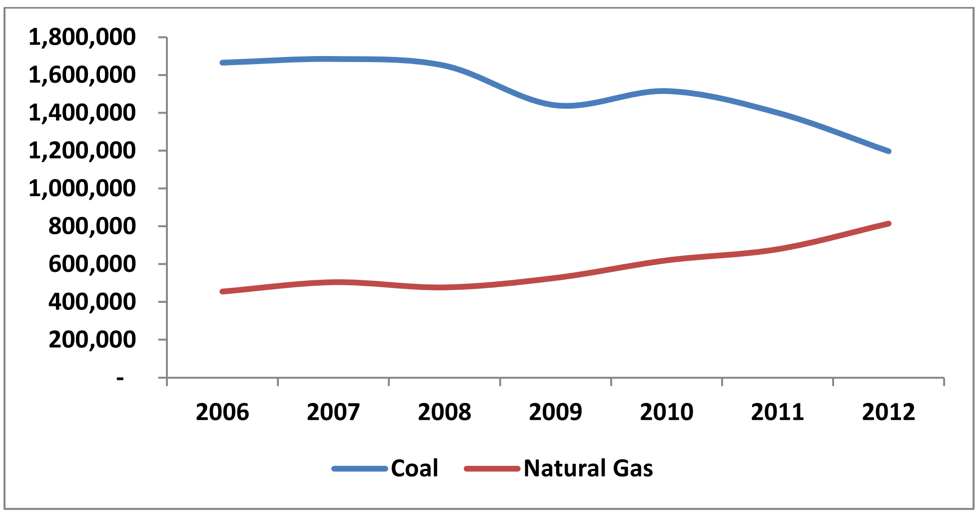
Source: EIA AEO2013 Early Release Overview

Illustrated in Exhibit 90, on a national level, shale gas production has increased tremendously since 2008, and more gas is expected to be unlocked in the future. By 2040, shale plays is expected to be the primary source for natural gas development in the United States. States within the EI have also witnessed a spike in shale gas production. Since 2008, shale gas production within the EI has nearly tripled annually. While in 2008, the EI region contributed to only 29% of total shale gas production in the U.S., but the share grew to 80% in 2010. The sharp increase in shale gas development within the EI implies that both lower wellhead prices as well as lower basis differentials from the locally sourced gas is likely to strongly influence the landscape of the power generation industry in the EI.

6.2.2 Impact of low gas prices on existing coal plants

Within the Eastern Interconnection, approximately 55% of total power generation was from coal-fired sources in 2008, while the share of gas-fired generating resources was 16%. By 2012, generation from coal-fired sources decreased to 42%, and natural gas generation increased to 29%.[175] In other words, 13% of total generation in the Eastern Interconnection shifted from coal-fired to gas-fired sources from 2008 to 2012.

Exhibit 91: Generation from Coal and Natural Gas Generating Sources in the EI (GWh)



Source: EIA, Survey-level Detail Data Files, State-level data, 2006 – 2012

In addition to the general trend of fuel shifting from coal to gas, multiple plants have announced plans to switch fuel from coal to gas. For instance, NRG proposed a plan to convert the Dunkirk coal facility to a combined cycle plant with a capacity of 450 MW to 600 MW; NRG also originally planned to achieve dual fuel capability by summer of 2013, and full combined cycle operations are expected to take place in summer of 2017.[176] Georgia power also announced in

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[175] EIA, Survey-level Detail Data Files, State-level data, 2006 – 2012.

[176] New York Energy Highway, NRG Energy's Dunkirk Combined Cycle and Huntley Gas Co-Firing Proposal, May 2012. http://www.nyenergyhighway.com/Content/documents/35.pdf

its recent integrated resource planning (IRP) that units 6 and 7 at Plant Yates will switch from coal to natural gas, and Plant McIntosh Unit 1 will switch from burning Central Appalachian coal to burning Powder River Basin coal.[177]

However, the growth rate in the share of gas-fired generation in total generation is not nearly as high as that of shale gas production. The shale gas growth in the power sector is more moderate due to a number of reasons. First, low load growth is forecasted for near future, and there is no immediate need to increase generating capacity on a large scale. Secondly, out of all different types of coal, Illinois Basin coal is experiencing an increase in popularity, because as gas prices gradually climb up back to the $4/MMBtu range, along with the widespread of installed environmental retrofits that are able to remove pollutants from Illinois Basin coal, renowned for its high sulfur content. While other coal types are experiencing declines in output, stable gas prices and environmental retrofits have enabled Illinois Basin coal to stage a comeback.[178] Additionally, the development of new natural gas capacity depends on the availability of pipeline infrastructure and pipeline capacity. In many regions within the EI, especially in the Northeast and Mid-Atlantic areas, electric-gas integration requires extensive cooperation and coordination between previously separated gas and electric sectors. Nonetheless, the development of natural gas from shale plays is expected to greatly influence the existing and future coal-fired capacity.

6.2.3 Impact on Coal Capacity Retirements and New Coal Plants

While announced retirements of coal fired capacity has been partly driven by an array of existing and upcoming environmental regulations[179], low current and projected gas prices have also provided an economic impetus for retirements, especially with decreasing dispatch and margins from coal plants. Generation owners have announced 47 GW of coal-fired capacity retirements for 2012 and beyond[180]; the remaining units of a total capacity of 276 GW that choose to continue to operate after 2016, when MATS becomes effective, will have to be sufficiently controlled and/or burning the types of coal necessary to comply with MATS. Besides current coal capacity facing the pressure to retire, new coal development is also limited by low gas prices.

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[177] PR Newswire, Georgia Power outlines 20-year plan to meet electricity needs. http://www.prnewswire.com/news-releases/georgia-power-outlines-20-year-plan-to-meet-electricity-needs-189254591.html

[178] Wall Street Journal, In the Midwest, Coal Stages a Comeback. http://online.wsj.com/article/SB10001424127887324582004578461324162944856.html

[179] A detailed analysis of the impact of environmental regulations on coal capacity can be found in *Task 2: Environmental Policy Concerns* in the Project Report.

[180] EPA, National Electric Energy Data System (NEEDS) v.4.10. http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html

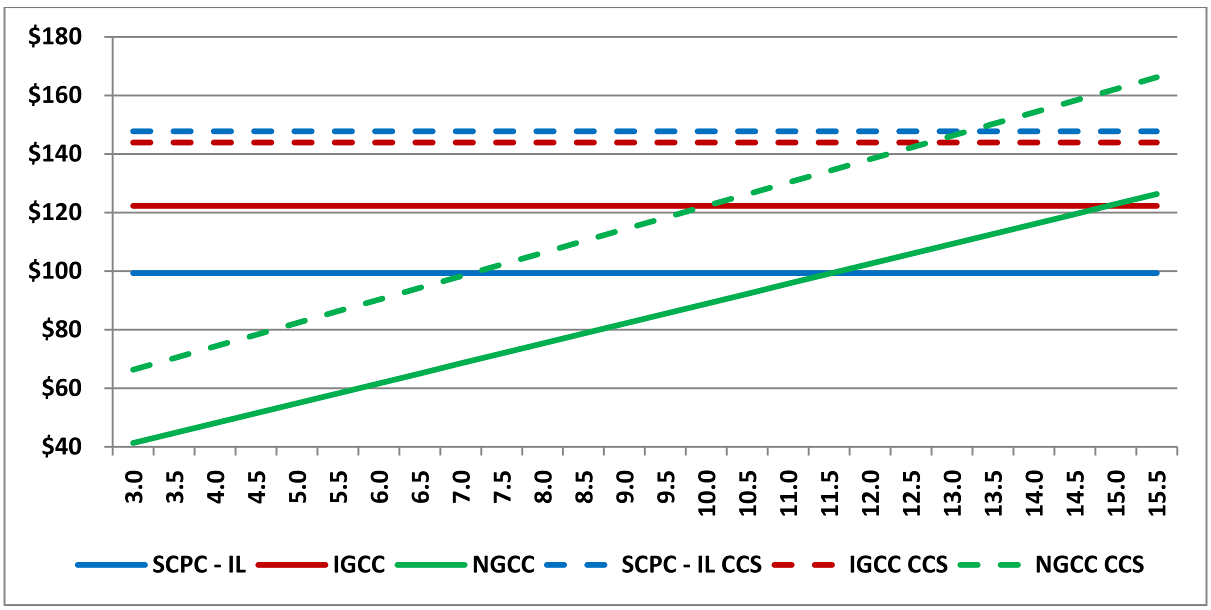
Exhibit 92: Levelized costs of electricity of Coal and Gas Plants for Year 2018 ($2011/MWh) [181]

	without CCS	with CCS
NGCC ($4.80/MMBtu Gas Price)	53.54	80.71
NGCC ($8.55/MMBtu Gas Price)	79.04	110.66
Subcritical Pulverized Coal	100.26	171.41
Supercritical Pulverized Coal	107.36	180.81
IGCC	122.30	162.61

Source: NETL, Cost and Performance Baseline for Fossil Energy Plants; EIA AEO2013 Early Release

Exhibit 92 shows the cost and performance data for new coal and natural gas plants with and without CCS technology (see Task 3 for details). The levelized cost assumed a $4.80/MMBtu gas price in the short term and an $8.55/MMBtu gas price in the long term, while the coal price stays between $2 and $3 per MMBtu. Exhibit 92 implies that the levelized costs of electricity from gas plants are significantly lower than that of coal plants. Exhibit 93 further illustrates how the levelized cost for natural gas plants increase with escalating gas prices (see Task 3 for details). Natural gas as a fuel source leads to lower levelized costs, even with CCS technology. As indicated in the chart below, only when gas prices are higher than $11.50/MMBtu does the levelized cost of energy of combined cycle plants exceed the cost of coal plants. In Exhibit 93, coal prices are assumed to stay between $2 and $3 per MMBtu.

Exhibit 93: Levelized Costs of Electricity from Coal and Gas Plants as a function of Gas Prices (2010$/MWh)[182]



[181] Details about levelized costs of electricity calculation can be found in *Task 3: Assessing Coal Technologies* in the Project Report.
[182] Details about levelized costs of electricity calculation can be found in *Task 3: Assessing Coal Technologies* in the Project Report.

In summary, with persistent low natural gas prices and more environmental regulations, natural gas continues to be the most cost effective generation fuel source. The persistently low historical and near-term forecasted natural gas prices provide with plant developers tremendous incentives to build gas-fired generation capacity in the United States. Levelized costs of electricity are expected to remain low for gas-fired plants, implying that new generation capacity in the US is primarily gas-based. Meanwhile, both existing and new coal capacities face challenges from current and upcoming environmental regulations. New coal development appears to be difficult to justify due to high costs compared to natural gas plants, and a significant fraction of the existing coal capacity is expected to retire within the Eastern Interconnection.

6.3 Impact of Electricity Markets and Reliability Planning Authorities (ISOs/RTOs)

The structure of electricity markets and reliability planning authorities such as Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) can also have an impact on the economics of existing coal-fired resources, as well as impact the future development of new coal plants. One of the primary functions of RTOs and ISOs is to manage transmission reliability issues and grid dispatch. Currently, four RTOs/ISOs function in the EI: ISO New England, NYISO, PJM Interconnection, and Midwest ISO.

There is also a mixture of traditionally regulated and competitive markets in the EI representing three different types of electricity market structures. Some regions, i.e. the Southeast, are served by traditionally regulated vertically integrated utilities exclusively. Competitive electricity markets were developed duting the 1990s in order to reduce the cost of electricity. Within the market areas of Midwest ISO and PJM Interconnection, individual state policies of implementing competitiveness in electricity markets have resulted in the different mix of market participants including independent power producers and utilities. The markets in the Northeast, under NYISO and ISO New England, are competitive.

In the Southeast, customers are served by vertically integrated utilities. Under this more traditional structure, a utility acts as the scheduling and balancing authority, and resource planning efforts are undertaken by the utility through integrated resource planning (IRP) processes. While vertically integrated utilities conduct the IRP for generation, transmission, and distribution, state regulatory commissions have the authority to scrutinize the process.

6.3.1 Competitive Electricity Markets

Competitive electricity markets rely on three classes of market products: energy, capacity, and ancillary services[183]. Energy markets usually consist of two markets: a day-ahead market and a real-time balancing market. For instance, in PJM, the day-ahead market is a forward market

[183] Ancillary services support the reliable operation of the transmission system as it moves electricity from generating sources to retail customers. For instance, in PJM, as part of the ancillary services, synchronized reserve supplies electricity if the grid has an unexpected need for more power on short notice; regulation is a service that corrects for short-term changes in electricity use that might affect the stability of the power system.

where clearing prices are determined for each hour of the next operating day. The real-time balancing market calculates clearing prices every five minutes based on actual system operations and dispatch.[184]

With price caps in energy market bids in all ISOs and RTOs in the EI, capacity markets provide a mechanism to supplement energy and ancillary service market revenues in order to ensure that enough new capacity comes online to meet system resource adequacy requirements.

Within the Eastern Interconnection, ISO-NE, NYISO, PJM Interconnection, and MISO all carry out their own versions of centralized capacity market mechanisms. By creating and maintaining a centralized capacity market, RTOs/ISOs are able to ensure that a threshold level of generating capacity and reliability is achieved to maintain reserve margin requirements. Moreover, a vibrant capacity market encourages existing and new generation resources to participate in the market by recognizing and valuing their contributions to local reliability requirements.

While PJM, ISO-NE, and NYISO require participation in capacity markets, MISO is currently experimenting with a voluntary capacity market. MISO states maintain a dominant role in determining reliability requirements and capacity procurements for their utilities.

Initially, the capacity markets relied on a fixed annual capacity requirement, which resulted in high volatility in prices – reaching maximum allowable limits if the capacity was slightly short or close to the requirement, but resulting in close to zero prices if the available capacity was in excess of minimum capacity requirements. However, within the last decade, demand curves have been introduced in the capacity markets to eliminate these issues, as demand curves are a more dynamic tool to encourage the financing of the development of new resources when needed.

6.3.2 Varying Characteristics of Capacity Markets in the Eastern Interconnection

Although shared objectives and principles are in place, the four RTOs/ISOs in the Eastern Interconnection – ISO-NE, NYISO, PJM, and MISO – all carry out their own versions of capacity markets. There are a number of notable differences among the capacity market practices. First, the commitment period of procuring capacity differs from market to market. Exhibit 94 shows the amount of time a supplier can commit in a capacity market auction. Longer commitment periods tend to encourage long-term investments, as a longer time period of supply implies a more secure revenue stream from capacity markets in order to recover costs. However, none of the capacity markets currently extend beyond three years[185], which can be problematic for the development of coal power plants, as they require long term commitments that capacity markets currently do not provide.

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[184] PJM, PJM Manual 11: Energy & Ancillary Services Market Operations. http://www.pjm.com/~/media/documents/manuals/m11.ashx

[185] The exception to this is that some ISOs/RTOs include provisions for new entrants to lock in capacity market prices for multiple years such as in ISO-NE where new entrants can receive the clearing price at the FCA entry year price for five years. http://www.iso-ne.com/markets/mktmonmit/rpts/other/fcm_report_final.pdf

Exhibit 94: Capacity Markets in the Eastern Interconnection – Commitment Periods

	ISO-NE	NYISO	PJM	MISO
Auction Name	Forward Capacity Auction (FCA)	Installed Capacity (ICAP) & Unforced Capacity (UCAP)	Reliability Pricing Model Auctions (RPM)	Voluntary Capacity Auction (VCA)
Commitment Periods	3 years	1 month and 6 months	3 years	1 year
Procurement Periods (New)	1 – 5 years	N/A	3 years	N/A

The second notable difference among various capacity markets is the level of CONE, as indicated by Exhibit 95. CONE, which is a key parameter of demand curves introduced in the capacity markets, is calculated in each region separately. Generally, CONE is associated with the cost of building new gas-fired units, often peaking units. In ISO New England, CONE is determined based on the net levelized cost of building CC and CT units without long term contracts. In NYISO and PJM, CONE is based on the levelized annual cost of a reference combustion turbine.[186] In MISO, the most recent estimate of CONE is based on costs associated with gas combined-cycle and gas combustion turbine generation resources.[187]

Exhibit 95: CONE in the Eastern Interconnection

	Recent CONE ($/kW-Year)
ISO New England	58.80
NYISO	175.80 – 388.32
PJM Interconnection	131.40 – 141.60

*CONE will not be applicable in ISO New England from next auction cycle and on.

When supply hits the targeted level of capacity requirement in each region, the demand curve price equals the "net CONE", which equals CONE minus energy and ancillary services revenues. Lower levels of supply result in higher prices, which encourage new entry, and higher levels of supply above the targeted level of reserve margin result in lower capacity prices. In other words, net CONE serves as a metric for utilities to determine whether or not they should invest in retrofitting existing resources and developing new generating resources.

At present, capacity prices remain low in various markets due to low gas prices, low load growth forecast, and higher volume of non-generation resources, i.e. demand response mechanisms, that are included in the supply stream. For instance, for the NYC zone in NYISO, the strip auction results (6-month) for summer have been hovering between $144/kW-Year and $180/kW-Year from 2010 to 2013; for winter, the auction results have been much lower, ranging

[186] PJM Manual 18: PJM Capacity Market. http://www.pjm.com/~/media/documents/manuals/m18.ashx.

[187] Errata Filing of Midwest Independent Transmission System Operator, Inc. Regarding Annual CONE Recalculation. https://www.midwestiso.org/Library/Repository/Tariff/FERC%20Filings/2011-08-03%20Docket%20No.%20ER11-4185-000.pdf

from $32/kW-year to $54/kW-year from 2010 to 2013.[188] In PJM, for 2015/2016 delivery year, the RTO clearing prices for capacity was $496/kW-year. For 2016/2017 delivery year, the actual clearing prices ($215/kW-year) were much lower than the consensus expectation ($365/kW-Year).[189]

According to projections from the EIA AEO2013**[190]**, electricity prices from generation for the PJM region in 2018 would be $54/MWh (2011$/MWh). Based on ICF's calculations**[191]**, the levelized cost of electricity is $53/MWh for NGCC without CCS, and $80/MWh for NGCC plants with CCS. Therefore, revenues from energy and capacity market are sufficient to recover the costs of a new natural gas-fired plant. However, for supercritical coal-fired plants with CCS, the levelized cost of electricity is about $148/MWh, which requires a capacity revenue equivalent of $94/MWh to recover total unit costs. The 2015/2016 capacity price in PJM is $57/MWh and the 2016/2017 capacity price is $25/MWh**[192]**. As a result, capacity prices remain significantly below the required capacity revenue for all coal-fired generation options.**[193]** Volatility and the short-term nature of the capacity markets further exacerbate the problem.

6.3.3 Implications for Existing and New Coal-fired Plants

If energy prices remain low, as is currently the case with low gas prices, low load growth, increasing demand resources, and capacity prices remain depressed due to the excess supply of capacity and other factors, the additional costs of retrofits needed to comply with more stringent environmental regulations might force a greater fraction of the existing coal-fired fleet out of the market through retirement or conversion to natural gas.

High reserve margins and low load growth remains a critical challenge for new entrants in general, and even more so for coal plants whose costs are much higher than CONE. Furthermore, there are no mechanisms in the power markets to internalize the value of fuel diversity, fuel security, or other public policy considerations. Hence, the new thermal generating units that have cleared in recent capacity auctions have overwhelmingly been natural gas-fired plants. Any requirements to incorporate CCS technology driven by climate change regulation, with its additional costs and technology risks, will further disadvantage new coal plants relative to gas.

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[188] NYISO, Strip Auction Results. http://icap.nyiso.com/ucap/public/auc_view_strip_detail.do

[189] PJM, RPM Auction User Information. http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx

[190] EIA AEO2013, Electric Power Projections for EMM Regions, Reliability First Corporation/East, Reference Case.

[191] Details about levelized costs of electricity calculation can be found in *Task 3: Assessing Coal Technologies* in the *Final Study Report*.

[192] We did not account for forced outages in this conversion.

[193] Assuming a nominal levelized capital charge rate of 16.6% for coal-fired plants without CCS, 13.6% for coal-fired plants with CCS, and 11.9% for gas-fired sources.

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