



EISPC

EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

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

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

1 Introduction

The Eastern Interconnection States' Planning Council (**EISPC**) represents the 39 states, the District of Columbia, the City of New Orleans, and the eight Canadian provinces located within the Eastern Interconnection electric transmission grid. One of EISPC's goals is to evaluate transmission development options within the Interconnection, and as part of that effort ICF International (**ICF**) was commissioned to conduct a study for EISPC focused on the present state and future direction of coal-fired electricity generating capacity in the U.S. portion of the Eastern Interconnection (hereafter simply referred to as the **EI**).

This Whitepaper is a summary of ICF's research exploring the challenges and opportunities faced by coal-fired generating resources. Coal capacity in the US is concentrated in the Eastern part of the country, with 84% of national coal-fired capacity within the EI. Due to a combination of existing and proposed environmental regulations and low gas prices, existing coal-fired generating facilities are facing a choice of whether to retire or to spend the necessary capital to comply with the regulations. Future development of coal-fired resources is also challenged by increasingly stringent environmental regulations. Additionally, the future for new coal-fired generating resources will continue to be impacted by uncertainties around the commercial availability of carbon capture and storage (CCS) technologies and the costs of building new coal-fired units.

The Whitepaper is organized into five sections. Following the Introduction, the next section describes the state of coal-fired capacity in the Eastern Interconnection, including geographic distribution of coal-fired capacity in the EI. The subsequent section outlines five major challenges to both existing and future coal power plants: current and anticipated environmental regulations and their associated impacts; development of shale gas resources and the impact of low natural gas prices; current state of development of CCS technologies; comparisons of levelized costs of electricity of various types generating resources (including CCS); and impact of electricity markets and regional planning authorities. The next section describes potential opportunities for coal power based on state level incentives for coal-fired power generation and the coal mining industry, followed by the concluding section.

Where appropriate, material presented here references specific sections of ICF's Final Study Report that contains all six of the Task reports developed throughout this study.

2 Coal-fired Capacity and Generation in the Eastern Interconnection¹

The vast majority of coal-fired units in the U.S. are located within the EI, and coal still serves as the most common fuel source for power generation in the EI and in the U.S. as a whole. In 2010, within the EI there were approximately 269 GW of coal-fired capacity comprised of 1,099 individual coal units, which accounted for 84% of U.S. coal capacity and 87% of coal units in the U.S.² Of the 269 GW of capacity in the EI, roughly one-third are located in the following five states: Illinois, Indiana, Ohio, Pennsylvania, and West Virginia.³ These units heavily rely on bituminous and sub-bituminous coal. Geographically, the EI covers the following six NERC regions: Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RFC), Midwest Reliability Organization (MRO), Sothern Power Pool (SPP), Southeastern Electric Reliability Council (SERC), and Florida Reliability Coordinating Council (FRCC). In 2010, 204 GW (75% of total coal capacity in the EI) was located in RFC and SERC.

In terms of generation of electricity, coal accounts for the largest percentage of total US generation. In 1985 coal provided 53% of U.S. generation but over the past 30 years, the national fuel mix has undergone a gradual shift to a more diverse mix of fuels as illustrated in Exhibit 1.⁴ Coal-based power generation grew during the 1990s but began to hit a plateau at around 2 TWh in the 2000s. With the economic crisis in 2009, coal-based generation (as well as the overall power demand) dropped. Although there was some recovery in 2010, coal-based generation has continued to drop in 2011 and 2012. Nationally, coal generation reduced to about 35% of total generation in 2012.⁵ However, based on data from the first quarter of 2013 from the EIA, recent rise in natural gas prices has led coal to regain some market share. According to Form EIA-923 detailed data, coal-fired generation contributed to 40% of total electricity generation in the United States.⁶ At the same time, from 1990 to 2012, the share of generation from natural gas-fired units nationally has increased from 11% to 28%, and the total generation from gas continues to increase on an annual basis. Total nuclear generation in the region 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 has not kept pace with demand growth, and the share of nuclear power as part of the generation mix has begun to erode.

Similar to the national trend, demand for coal-based electricity in the EI has stayed relatively flat in most of 2000s, followed by a drop due to the economic crisis in 2009, as illustrated in Exhibit 2. There is also an evident switch from coal-fired to gas-fired resources in terms of generation levels with the gas-based generation increasing from 11% of power demand in 2001 to about 28% in 2012. Furthermore, overall demand for electricity as also decreased slightly in the EI over the last few years, with increased energy efficiency and demand resources making up for the difference.

¹ Please refer to *Final Study Report, Task 1: Unit-level and Aggregate Data on Coal-fired Units* for more details.

² EPA, National Electric Energy Data System (NEEDS) v.4.10.
<http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#needs>

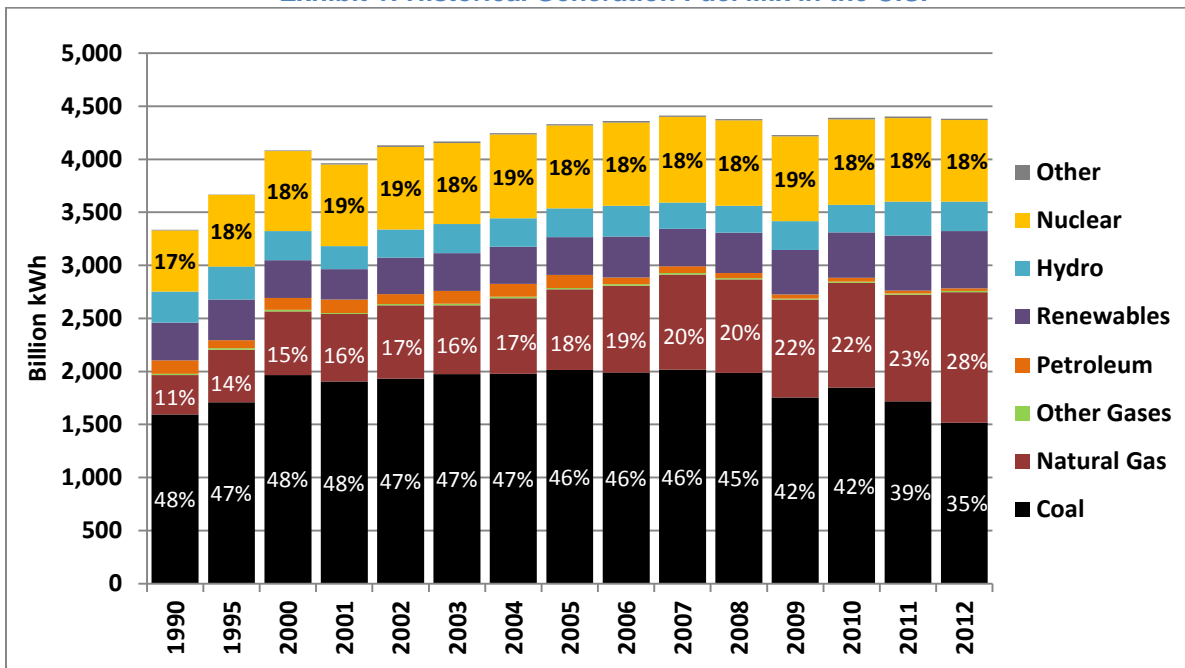
³ Please refer to *the Final Study Report, Task 1: Unit-level and Aggregate Data on Coal-fired Units, 1.1 State-by-State Detail of Coal-fired Units* for more details.

⁴ Please refer to *the Final Study Report, Task 1: Unit-level and Aggregate Data on Coal-fired Units, 1.2 Historical and Current Fuel Mix for the Eastern Interconnection and the U.S.* for more details.

⁵ EIA, Electricity Data. <http://www.eia.gov/electricity/data.cfm#generation>

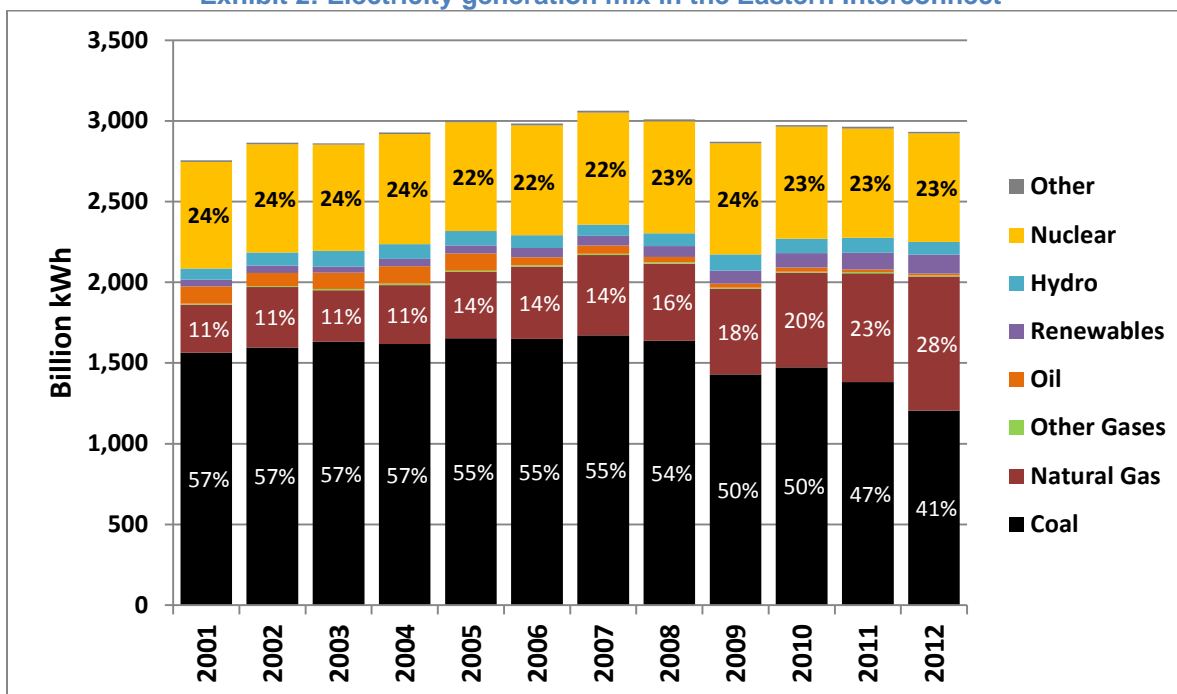
⁶ EIA, Electricity, Form EIA-923 detailed data. <http://www.eia.gov/electricity/data/eia923/>

Exhibit 1: Historical Generation Fuel Mix in the U.S.



Source: EIA, Annual Energy Review; EIA, Electric Power Monthly

Exhibit 2: Electricity generation mix in the Eastern Interconnect

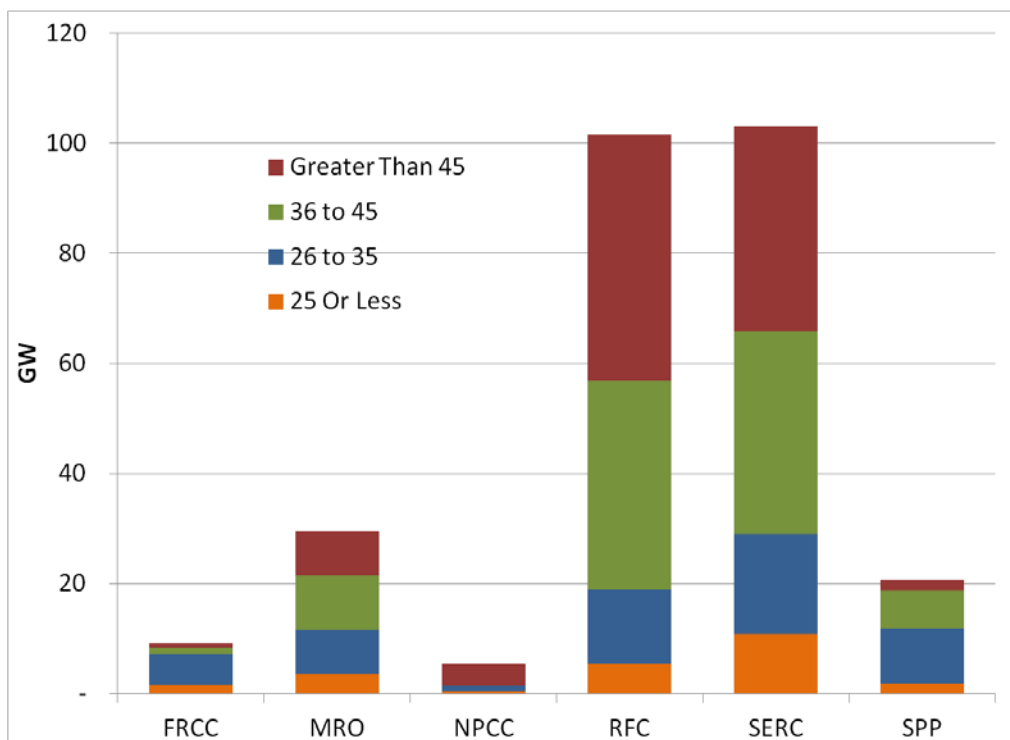


Source: EIA, Electric Power Monthly⁷

⁷ Prior to 2001, EIA monthly electricity generation data (form 906/920/923) by capacity type included utility owned plants only. From 2001 and on, generation data by capacity type includes both utility and non-

The coal plants in the EI are relatively old, with significant amount of coal units in RFC and SERC being older than 50 years, as indicated in Exhibit 3. By 2015, roughly half of the coal-fired units in the Eastern Interconnection will be 50 years of age or older, and on a state level, the average age of all coal units in the five states of Illinois, Indiana, Ohio, Pennsylvania, and West Virginia will be nearly 50 years by 2015. Hence, it is likely that these regions have the greatest potential for retirements and subsequent transmission related changes.⁸

Exhibit 3: Coal-fired Capacity by Age and NERC Region



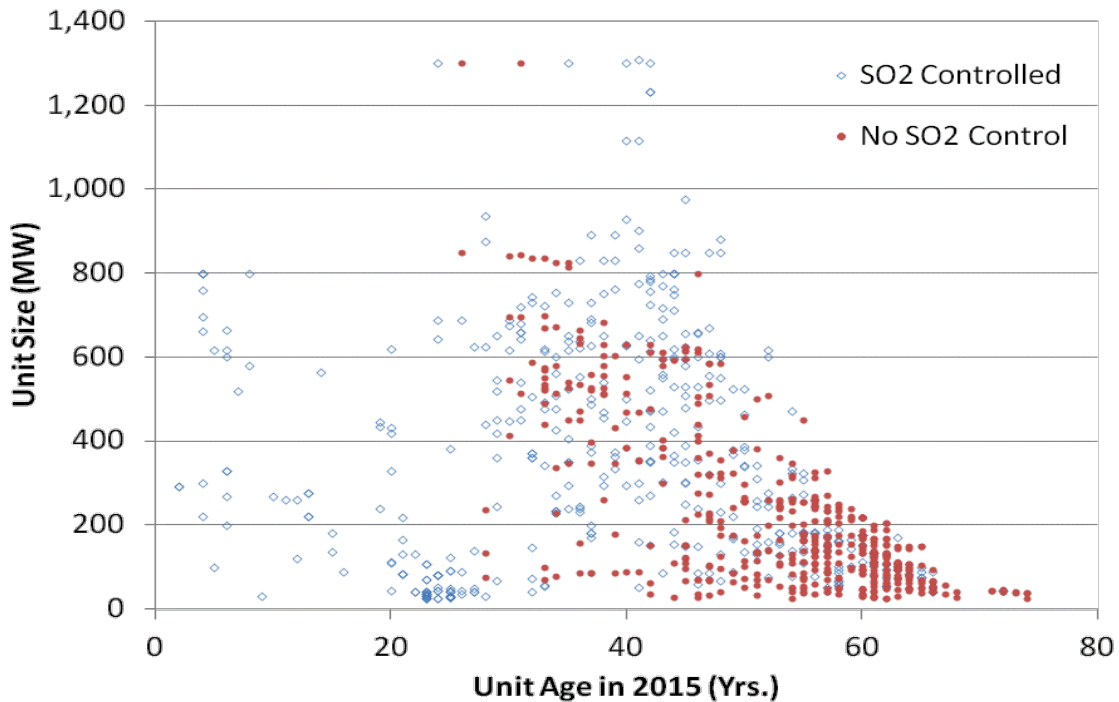
Source: EPA, National Electric Energy Data System (NEEDS) v.4.10

Furthermore, as shown in Exhibit 4, the older units tend to be smaller in terms of capacity (although, they altogether still represent 25% of total capacity), and these older units also tend to be the ones without emission controls. These units that have been operating for 50 years and longer – and uncontrolled for SO₂ – represent the subset of units with the highest risk of retirement.

utility generating facilities. In 2000, approximately 688,180 billion kWh of electricity was generated from non-utility sources, which explains the gap between 2000 and 2001 generation data.

⁸ The average full load heat rates in the EI range from over 12,000 Btu/kWh to 9,600 Btu/kWh. Heat rates are affected by a host of factors including the age, size, fuel, technical configuration, and the environmental controls of a plant.

Exhibit 4: Status of SO2 Controls of Coal Units Greater than 25 MW in the EI



Source: EPA, National Electric Energy Data System (NEEDS) v.4.10

3 Challenges for Coal-fired Capacity in the Eastern Interconnection

Coal-fired generation – both existing and new – face a variety of challenges at present and in the short-to-medium term future: more stringent environmental regulations, low natural gas prices, higher capital costs (especially for new technologies), and changing electricity market dynamics. This section discusses each of these major drivers, with the analysis focused on both existing and new coal-fired power plants.

3.1 Environmental Regulations

Existing and proposed environmental regulations play a key role in shaping the future of new and existing coal-fired power plants. As illustrated in Exhibit 4, there are five major categories of environmental regulations (in final and draft forms) that affect the power sector, with some mainly impacting existing plants and others impacting both new and existing plants. These regulations also face numerous legal challenges, creating an uncertain planning environment for plant owners, operators, and regulators. Each of these regulations is described briefly below, along with their implications for both existing and new coal-fired power plants.

Exhibit 5: Five 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								

Note that President Obama’s Climate Action Plan released on June 25th, directed EPA to regulate GHGs through NSPS

3.1.1 Clean Air Interstate Rule (CAIR) and the Cross State Air Pollution Rule (CSAPR)⁹

The Clean Air Interstate Rule (CAIR) was originally finalized by the U.S. Environmental Protection Agency (EPA) in March of 2005 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)¹⁰. The purpose of CAIR was to address the interstate transport of these pollutants to facilitate counties that were in “downwind” non-attainment status to reach attainment status. SO₂ and NO_x emissions (NO_x from transportation and power plants and SO₂ almost exclusively from power plants) are precursors to PM_{2.5} formation. Therefore, the SO₂ 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 attain the current 8-hour ozone standard. The rule covered 27 states and the District of Columbia.

In 2008, the U.S. Court of Appeals for the D.C. Circuit issued a ruling vacating CAIR in its entirety. 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 on industry feedback. EPA intended for CSAPR to replace CAIR beginning on January 1, 2012. CSAPR consisted of annual requirements for SO₂ and NO_x emissions and ozone-season requirements for NO_x emissions (although for different groupings of states). Under CSAPR, all of the covered states¹¹ are in the EI, and they were given budgets under each program. Affected entities within CSAPR covered states were then provided with allowances based on extensive modeling concerning their contributions to their state’s 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, entities would have been charged with penalty allowances should their

⁹ Please refer to *the Final Study Report, Task 2: Environmental Policy Concerns, 2.1 Clean Air Interstate Rule (CAIR) and the Cross State Air Pollution Rule (CSAPR)* for more details.

¹⁰ NAAQS sets standards for six pollutants: carbon monoxide (last updated in August 2011); lead (last updated in November 2008; nitrogen dioxide (last updated in February 2010); ozone (last updated in March 2008); PM_{2.5} and PM₁₀ (last updated in December 2012); sulfur dioxide (last updated in June 2010).

¹¹ States are included in the CSAPR are as follows: Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

emissions cause their state to exceed its annual allowance budget plus an assurance level of 18%, which limited interstate trading—an aspect that the Courts ruled against in CAIR.

CSAPR impacted about 1,000 coal-, gas-, and oil-fired facilities. Coal-fired plants would need to achieve emission reductions by the following: effective and frequent operation of retrofit equipment; usage of low sulfur coal; more generation from cleaner units; and installation of additional retrofit controls.¹² The cost of investing in scrubbers and SCR units could be as high as 120 billion by 2015.¹³

On August 21, 2012, however, the court vacated the CSAPR rule in its entirety due to two primary reasons: a) EPA exceeded its authority under the Clean Air Act by mandating that a state reduce its emissions beyond its level of significant contribution; and b) EPA overstepped its authority because under CSAPR, EPA executed a federal implementation plan (FIP) before giving the state the opportunity to initiate and execute a state implementation (SIP).. As part of the ruling, the Court required EPA to continue to enforce CAIR, even though the court had previously ruled against CAIR as well. 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 SO₂ and NO_x (summer and annual) emissions each year. CAIR allowance prices remain low due to a very large bank of existing Title IV SO₂ allowances and modest requirements for emissions reductions. The costs are likely to remain low until more stringent regulations are promulgated in order to achieve the more stringent NAAQS standards – most likely through the implementation of a new program. On the other hand, given the legal problems EPA has faced in getting market-based mechanisms for controlling these criteria pollutants, EPA may consider command and control-type approaches¹⁴.

3.1.2 Mercury and Air Toxics Standards (MATS)¹⁵

EPA finalized the Mercury and Air Toxics Standard (MATS) rule on December 21, 2011, specifying requirements to control emissions of particulate matter (PM), acid gases (HCl as a proxy), and toxic metals (mercury is used as a proxy) 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 maximum emission rates 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 existing units are ranked and emissions rate from the top 12 percent of the best performing existing units are used to set the limits.

MATS sets compliance requirements for three pollutants as surrogates for larger classes of pollutants: mercury (proxy for toxic heavy metals), 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).

¹² EPA, Fact Sheet The Cross-State Air Pollution Rule: Reducing the Interstate Transport of Fine Particulate Matter and Ozone. <http://www.epa.gov/crossstaterule/pdfs/CSAPRFactsheet.pdf>

¹³ American Legislative Exchange Council, Cross State Air Pollution Rule. <http://www.alec.org/wp-content/uploads/CSAPR-design-FINAL.pdf>

¹⁴ The Supreme Court, on June 24, 2013 decided that it would review the Appeals Court rejection of CSAPR, potentially leading the way to its reinstatement. A decision is not expected until Spring 2014.

¹⁵ Please refer to *the Final Study Report, Task 2: Environmental Policy Concerns, 2.2 Mercury and Air Toxics Standards (MATS)* for more details.

The EPA claims that the final MATS rule will eliminate 90% of mercury emissions from power plants, 88% of acid gas emissions, and reduce SO₂ emissions 41% more than what they expected to achieve through CSAPR.¹⁶ The EPA projects the cost of MATS to be an annualized \$9.6 billion.¹⁷ Under MATS, many coal- and oil-fired power plants will incur capital and increased variable operating and maintenance (VOM) 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 great portion of this cost.

The Exhibit below shows various types of environmental retrofit controls for each type of pollutant. Retrofit options to control mercury emissions include standard activated carbon injection (SPAC-ACI) system, modified activated carbon injection (MPAC-ACI) system, and SO₂ and NO_x control technologies that also bring benefits to mercury control. Therefore, MATS effectively rules the need for additional controls for CSAPR/CAIR—although, a new NAAQS for PM2.5 might again require new controls for SO₂ and NO_x.

Exhibit 6: Summary of Emission Control Technology Retrofit Options¹⁸

SO ₂ Control	NO _x Control	Hg Control
Limestone Forced Oxidation (LSFO) Scrubber	Selective Catalytic Reduction (SCR) System	Standard Activated Carbon Injection (SPAC-ACI) System
Lime Spray Dryer (LSD) Scrubber	Selective Non-Catalytic Reduction (SNCR) System	Modified Activated Carbon Injection (MPAC-ACI) System
Dry Sorbent Injection (DSI)	Combustion Controls	SO ₂ and NO _x Control Technology Removal Benefits

3.1.3 Cooling Water Intake¹⁹

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 to reduce both the impingement and entrainment of aquatic life. Compliance requirements will be determined by each state following

¹⁶ 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/20111221MATSimfactsfs.pdf>

¹⁷ EPA, Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, December 2011.

¹⁸ A detailed description of each type of environmental retrofit option can be found in the Final Study Report Task 4, 4.2 Overview of Environmental Retrofits.

¹⁹ Please refer to *the Final Study Report, Task 2: Environmental Policy Concerns, 2.3 Cooling Water Intake Structures* for more details.

site-specific assessments related to the cost and performance of potential entrainment reduction options.

EPA must issue the final standards by late June 2013²⁰, according to a recent court agreement.²¹ Affected sources must achieve compliance with the impingement requirements no later than eight years after the final rule is issued. The rule will phase in compliance with the entrainment standards over time as units renew their National Pollutant Discharge Elimination System (NPDES) permits. 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.²²

3.1.4 Coal Combustion Residuals (Ash) and Effluent Limitations Guidelines (ELG)²³

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 by electric utilities and/or independent power producers.²⁴ EPA has identified a total of 427 coal-fired units nationwide that manage CCRs.²⁵ Based on RCRA, EPA created a framework for the management of hazardous and nonhazardous solid wastes, including ash from coal-fired boilers. Although there are two potential regulatory approaches to reduce wet handling of ash: as hazardous (under RCRA Subtitle C) and non-hazardous (under Subtitle D). Treatment of the CCRs as hazardous waste could potentially add significant costs to the disposal of ash. Potential modifications 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 facilities for units with existing wet scrubbers.

In addition, under the Clean Water Act, effluent limitations are to be revised every five years, however, effluent limitations were last revised in 1982. The D.C. Circuit Court mandated requirement calls for action by May 22, 2014, based on a consent decree between EPA and Defenders of Wildlife, EarthJustice, Environmental Integrity Project, and Sierra Club. On April 19, 2013, EPA issued a notice of proposed rulemaking to revise the technology-based effluent limitations guidelines (ELG) and standards for the coal power industry to strengthen the existing controls on discharges. The proposal sets the first federal limits on the levels of toxic metals in

²⁰ EPA announced on June 26th that the final standards will be delayed until September 2013.

²¹ 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.

²² 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>

²³ Please refer to *the Final Study Report, Task 2: Environmental Policy Concerns, 2.4 Coal Combustion Residuals (Ash) and Effluent Limitations Guidelines (ELG)* for more details.

²⁴ 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.

²⁵ Fact Sheet: EPA Region IX Coal Combustion Residuals (CCR) Surface Impoundments. http://www.epa.gov/region9/waste/enforcement/pdf/2009_R9-CoalAsh-factsheet.pdf

wastewater from power plants.²⁶ The proposed rule is expected to reduce 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.²⁷ The majority of coal-fired power plants are expected to incur no additional cost under any of the proposed standards.²⁸ EPA intends to align ELG with CCR rule proposed in 2010 under RCRA, seeking comments from industry and other stakeholders to ensure both ELG and CCR final rules are aligned, so that pollution is reduced efficiently while minimizing regulatory burdens.²⁹ 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 altered the draft version of the proposed rule.³⁰

3.1.5 Greenhouse Gases (GHG) New Source Performance Standards (NSPS)³¹

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 CO₂/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 and storage (CCS) technologies. 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. For the purpose of this rule, fossil-fuel-fired electric utility generating units include fossil-fuel-fired boilers, integrated gasification combined cycle (IGCC) units, and stationary combined cycle turbine units that generate electricity for sale and are greater than 25 MW.

There are several aspects of the proposed NSPS rule that have caused controversy, specifically among owners and operators of coal-fired plants. First, EPA has proposed a single-standard rule regardless of fuel type (i.e., there is no sub-categorization). 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, the proposed 1,000 lb. CO₂/MWh standard is fairly stringent and challenging for compliance. Such a standard requires a new coal-based unit to use CCS technologies, which is costly and not yet commercially available. And finally, 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 still 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.

²⁶ 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

²⁷ *Ibid.*

²⁸ 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>

²⁹ SNL, EPA poised to propose revised toxic wastewater discharge rules for power plants. <http://www.snl.com/interactivex/article.aspx?id=17505037&KPLT=6>

³⁰ SNL, Earthjustice: Document shows OMB 'significantly weakened' power plant discharge rule. <http://www.snl.com/Interactivex/article.aspx?ID=17930877>

³¹ Please refer to *the Final Study Report, Task 2: Environmental Policy Concerns, 2.5 Greenhouse Gases (GHG) New Source Performance Standards (NSPS)* for more details.

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 2015.³²

3.1.4 Impact on Existing Coal-fired Generating Resources

Older coal units without the required environmental retrofits represent the subset of units facing the highest risks of retirement, as noted in Section 1. To comply with environmental regulations, existing coal-fired units have two options: 1) retire the units from the generating fleet or 2) comply with the command and control based regulations, often through installing pollution control retrofits, and continue to operate. Generator owners have announced 47 GW of coal-fired capacity retirements for 2012 and beyond.³³ Two major factors driving the retirements are: implementation of MATS rule, which requires coal units to install mercury controls and/or SO₂ and NO_x controls, and low natural gas prices. The additional costs caused by environmental retrofit options are deemed too high by operators, who have announced they would opt to retire their units. Moreover, as natural gas prices remain low and power generation from gas-fired units becomes more economical (see discussion below), and operators are choosing to their coal-fired units.

The remaining units that choose to continue to operate after 2016, when MATS becomes effective, will have to meet the MATS requirements through a combination of additional environmental control equipment (see Exhibit 6) and access to the type of coal that allows them to comply with MATS and other environmental rulemakings. This implies that the remaining coal units after 2016 will be larger, cleaner, and have more dispatch than the existing set of coal units.

3.1.5 Impact on New Coal-fired Generating Resources

The future of new coal-fired capacity is also uncertain due to the additional environmental regulations, as cost of new coal power plants increase with the requirement of additional pollution controls. While any new generation facility will have to meet the criteria and toxic air regulations, water regulations, and effluent guidelines and ash handling regulations, it is the NSPS regulations, depending on how they are finalized, that could specifically make the construction of new coal plants without CCS virtually impossible. Yet, at the same time, CCS technologies are not yet fully commercial and are still in the demonstration phase, as discussed below. The drive for CCS technologies has become moribund, as prospects for imposing a price on carbon emissions has reduced significantly in recent years. The combination of these developments has resulted in an effective moratorium on new coal-fired power plants.

3.2 Commercial Availability of Advanced Coal Power Technologies

There are a number of advanced coal power technologies that are in various phases of development, demonstration, and commercialization. The standard coal power technology in the US today is supercritical pulverized coal (SCPC)³⁴, as it is considered a well-developed and

³² Executive Office of the President, The President's Climate Action Plan.

<http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>

³³ Announcements from power generators; EPA, National Electric Energy Data System (NEEDS) v.4.10.

<http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html>

³⁴ Globally, however, subcritical pulverized coal is considered as the base technology for coal fired power plants.

mature commercial technology. Advanced technologies include ultra-supercritical pulverized coal (USCPC), advanced circulating fluidized bed combustion (CFB), biomass cofiring with pulverized coal, chemical looping combustion (CLC), and integrated gasification combined cycle (IGCC) considered as new coal power technologies. While USCPC technologies have been commercialized in Europe and Japan, its availability and maturity remains a concern in the US. CFB based on subcritical steam cycle is a mature technology; however, CFB plants with supercritical steam cycle are not yet commercially proven in the US. Co-firing with a small percentage of biomass has been demonstrated, although co-firing with higher biomass injection remains a challenge. CLC is an immature technology for now, and there are only pilot projects testing the technology. All elements of IGCC plants are commercial by themselves, although full integration of gasification and combined cycle operation has not yet been fully commercialized. Duke Energy's Edwardsport IGCC plant (618 MW) is the largest IGCC in the US, and it has recently begun to operate commercially. According to estimates by the Indiana Utility Regulatory Commission, the capital cost of Edwardsport is approximately \$3.15 billion, or about \$5,100/kW,³⁵ which is much higher than estimates typically assumed for evaluating power plant costs—see Exhibit 7.

The capital cost estimates³⁶ of advanced coal power technologies are shown in Exhibit 7, based on information from the National Energy Technology Laboratory (NETL), which relies on an internal a cost model using specific assumptions about plant characteristics and performance, financing, and commodity prices. All of the technologies are assumed to use the Illinois No. 6 coal, except for SCPC (row 3), Ultra-Supercritical (row 4), and CFB (row 5) using PRB coal. Exhibit 7 shows that the capital costs for SCPC power plants are about 2.8 times more than natural gas combined cycle plants, with IGCC plants being even more (3.3 times) more expensive.

Exhibit 7: NETL's Estimates of Capital Costs for Coal Power Technologies (2011\$/kW)

Generating Technology	Without CCS Capital Cost (2011\$/kW)	With CCS Capital Cost (2011\$/kW)
PC – Subcritical	2,583	4,736
PC – Supercritical	2,617	4,686
PC – Supercritical (PRB)	2,967	5,231
Ultra Supercritical (PRB)	3,112	5,312
CFB (PRB)	3,050	5,271
Biomass Cofiring (15%)	2,672	4,901
Biomass Co-firing (60%)	2,843	5,004
IGCC	3,168	4,306

³⁵ SNL, Duke Energy's 618-MW Edwardsport IGCC enters commercial operation. <http://www.snl.com/interactivex/article.aspx?ID=17962018&KPLT=2>

³⁶ The costs shown are Total Overnight Costs, which includes equipment, labor, EPC contractor services, contingencies, financing costs, and other owners' costs. See: NETL, Cost and Performance Baseline for Fossil Energy Plants.

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

In addition to the above coal power technologies, a few years ago when gas prices were higher, coal gasification to make synthetic natural gas was considered a viable technology. This technology is no longer under serious consideration due to low gas prices and regulatory uncertainty. For instance, the developer of the Rockport project, which is a \$2.8 billion coal gasification facility in Southwestern Indiana, announced recently that it is halting the gasification project after state lawmakers passed a bill calling for a new round of regulatory review to consider additional ratepayer protection.³⁷ As a consequence, the development of a CO₂ pipeline, which would have transported captured CO₂ from the Midwest to enhanced oil recovery operations in the Gulf Coast, is stalled.³⁸

3.2.1 Carbon Capture and Storage Technologies

In order to meet any stringent NSPS requirements, carbon capture and storage (CCS) technologies will likely be required. Many view CCS as being the key to the long-term viability of coal-fired generating resources, especially as the world starts to focus on deep GHG reductions from power plants and other industrial facilities.

EPA's currently proposed draft NSPS for GHGs requires all new fossil fuel-fired power plants to meet an emissions rate standard of 1,000 lb CO₂/MWh, which is similar to the emission rate of natural gas combined cycle technologies. To comply with this proposed rule, plants need to either switch fuels or incorporate carbon capture and storage (CCS) technologies. Therefore, the commercial availability of CCS technology is a vital factor in determining the future of coal-fired plants in the United States, particularly within the EI where coal-fired capacity is concentrated.

The CCS process consists of three phases: a) capture and compression of CO₂; b) transporting the captured CO₂ to a storage site; and c) injecting and safely storing the CO₂ in underground geological reservoirs. Exhibit 8 illustrates these components of CCS.

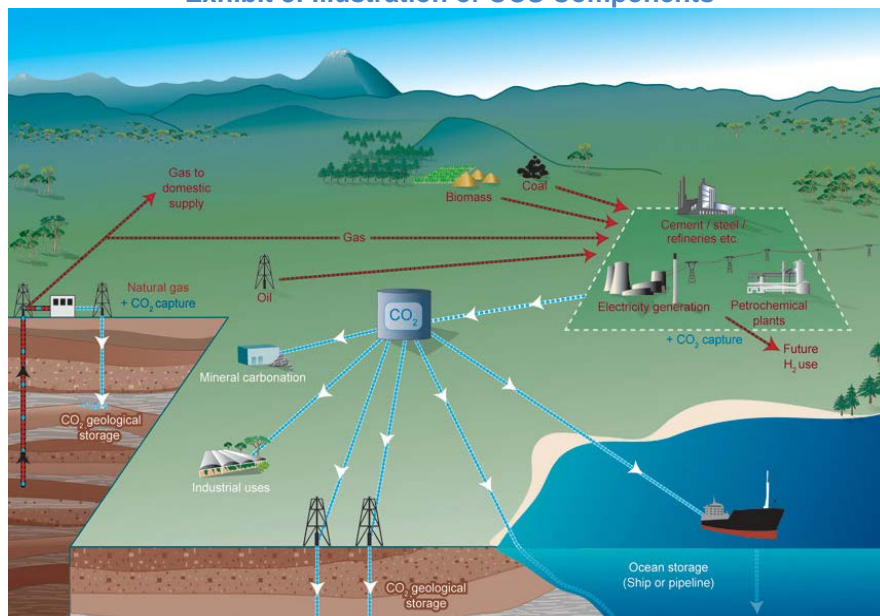
Widespread cost-effective deployment of CCS in the EI and elsewhere will occur only if the technology is commercially available and economically viable, and if there are supportive national policy and regulatory frameworks. Additional costs associated with CCS are a major barrier, as shown in Exhibit 7. For a new SCPC unit, the addition of CCS increases the capital cost by a factor of 1.8, and for a new IGCC, the costs goes up by a factor of 1.4. Hence, IGCCs are often touted as an important technology given the smaller percentage of increase in capital costs, although the technology is not as well tested as SCPC units. Without CCS, a new SCPC unit has a much lower LCOE compared to an IGCC unit. But when CCS is incorporated, the LCOE of an IGCC unit is lower than that of new SCPC unit with CCS. However, in terms of absolute costs, the capital costs for a NGCC plant with CCS³⁹ is still lower than coal power plants without CCS.

³⁷ GHG Reduction Technologies Monitor, Developer Suspends after Legislature Passes Bill Requiring Another Review. <http://ghgnews.com/index.cfm/developer-suspends-most-work-on-indiana-gasification-project/>

³⁸ Midwestern coal gasification plant and proposed CO₂ pipeline appear near termination, May 2, 2013. <http://www.eenews.net/public/climatewire/2013/05/02/1>

³⁹ By adding CCS to a NGCC plant, the capital costs go up by a factor of 2.1 (see Exhibit 7).

Exhibit 8: Illustration of CCS Components



Source: IPCC, 2005.⁴⁰

The development of fully integrated CCS projects is challenged by a variety of factors, including uncertainty in climate policy, commercial availability of the technology, and high costs. The first fully integrated CCS projects are facing economic challenges related to climate policy uncertainty, first-of-a-kind technology risks, and the current high cost of CCS relative to other technologies.⁴¹ Commercial deployment requires a significant price on carbon emissions (which currently does not exist) and/or high natural gas prices, and additional financial incentives are also likely required. In addition, CCS projects will need to meet regulatory requirements that are still mostly under development. Absent a specific legislation on CCS, existing regulatory programs are being adapted to allow for demonstration projects on CCS.

Currently, six large scale coal-fired power plants with CCS are in the planning stage or under construction in the U.S.: Trailblazer (Texas), Kemper County IGCC (Mississippi), TCEP (Texas), WA Parish (Texas), HECA (California), and FutureGen 2.0 (Illinois).⁴² There are multiple uncertainties around many of these projects. As of April 2013, the Southern Co. has withdrawn plans to seek a federal loan guarantee for the Kemper County IGCC plant.⁴³ Southern Company has claimed that Mississippi power can seek financing at a lower rate than available under the loan from the Department of Energy, but the source of funding is uncertain at present. FutureGen 2.0 – the only other plant within the EI – is expected to start construction in 2013,

⁴⁰ 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.

⁴¹ Report of the Interagency Task Force on Carbon Capture and Storage, August 2010.

⁴² MIT, Carbon Capture & Sequestration Technologies.

http://sequestration.mit.edu/tools/projects/index_capture.html

⁴³ Mississippi Business Journal, Southern decides against federal loan for Kemper coal plant.

<http://msbusiness.com/blog/2013/04/03/southern-decides-against-federal-loan-for-kemper-coal-plant/>

and a projected completion year of 2017. The nearly \$1 billion in federal stimulus funding has to be spent by end of September 2015. Therefore, delays in FutureGen's development can scuttle this flagship full-scale CCS demonstration project.⁴⁴ Uncertainties of financing and timeline for power plant CCS projects indicate that the future of coal-fired generating resources is unclear.

The uncertain future of regulatory and legislative carbon policy casts further doubts on the future development of CCS, especially with limited funding available for technology development. Furthermore, even if a carbon policy comes to fruition, CCS may be deployed on natural gas plants before coal-fired plants,⁴⁵ if natural gas prices remain low (as discussed below).

In the meantime, some have called for "CCS Ready" policies which can pave the way for new (and existing) power plants to be retrofitted with CCS technologies as and when they are commercial available and required by regulations and/or economic drivers.⁴⁶ The aim of building such CCS Ready facilities is to reduce the risk of carbon emission lock-in or the facilities being stranded assets in the future.⁴⁷

3.3 Development of Natural Gas from Shale Resources

3.3.1 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.⁴⁸ 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 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%.⁴⁹ Production and consumption of natural gas grew at approximately 3.7% and 1.4%

⁴⁴ Congressional Research Services, FutureGen: A Brief History and Issues for Congress.

<http://www.fas.org/sqp/crs/misc/R43028.pdf>

⁴⁵ Eide, Jan. Rethinking CCS – Strategies for Technology Development in Times of Uncertainty.

http://sequestration.mit.edu/pdf/2013_JanEide_Thesis.pdf

⁴⁶ <http://www.globalccsinstitute.com/institute/media-centre/media-releases/ccs-ready-paves-way-carbon-capture-storage-deployment>

⁴⁷ <http://www.globalccsinstitute.com/publications/defining-ccs-ready-approach-international-definition>

⁴⁸ IEA, Are We Entering a Golden Age of Gas?

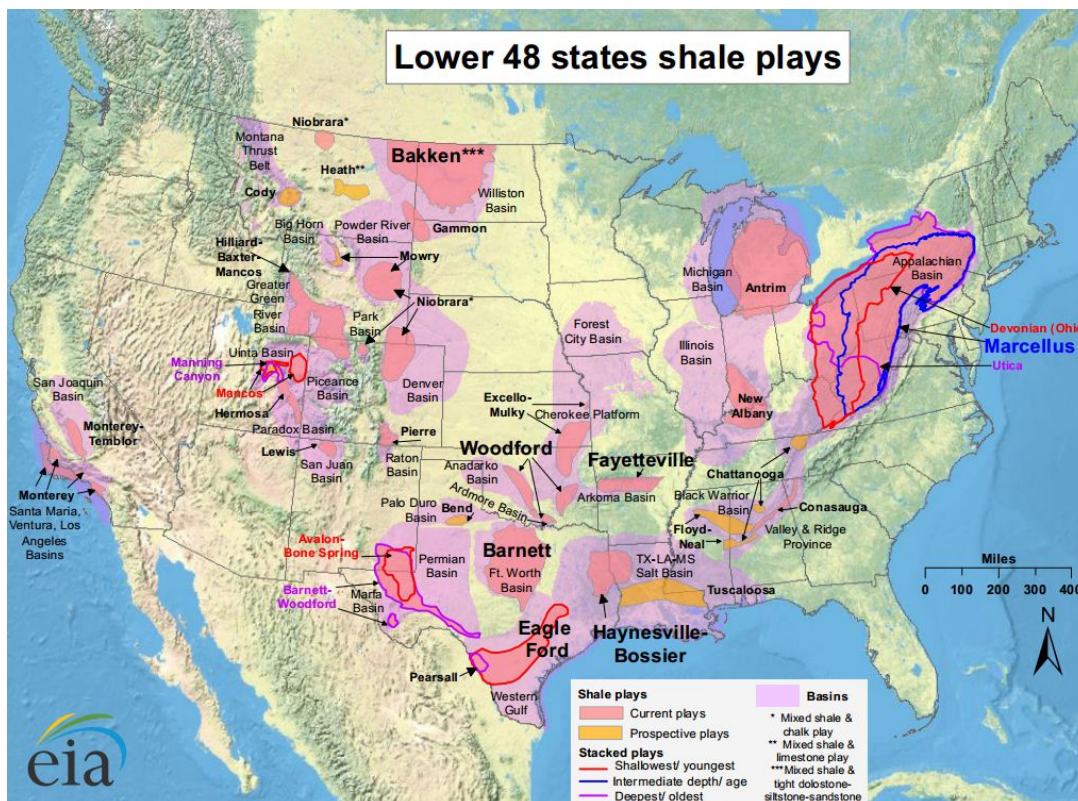
http://www.worldenergyoutlook.org/media/weowebiste/2011/WEO2011_GoldenAgeofGasReport.pdf

⁴⁹ U.S. Crude Oil, Natural Gas, and NG Liquids Proved Reserves.

<http://www.eia.gov/naturalgas/crudeoilreserves/>

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 2007.⁵⁰

Exhibit 9: Lower 48 States' Shale Plays



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

As indicated in Exhibit 9, the regions with the majority of technically recoverable shale gas resources are the Northeast, Gulf Coast, and Southwest. Within these three regions, the largest shale play is the Marcellus basin in the Northeast, which has contributed to 55% of total recoverable reserves in the United States; the Northeast as a whole has contributed to 63% of the total recoverable reserves.⁵¹

The abundance in recoverable reserves is also reflected by a sharp increase in shale gas production within the last few years illustrated in Exhibit 10. The shale gas production increase has accelerated since 2008 at the national level, 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 particularly witnessed a spike in shale gas production. Since 2008, shale gas production within the EI has nearly tripled annually,

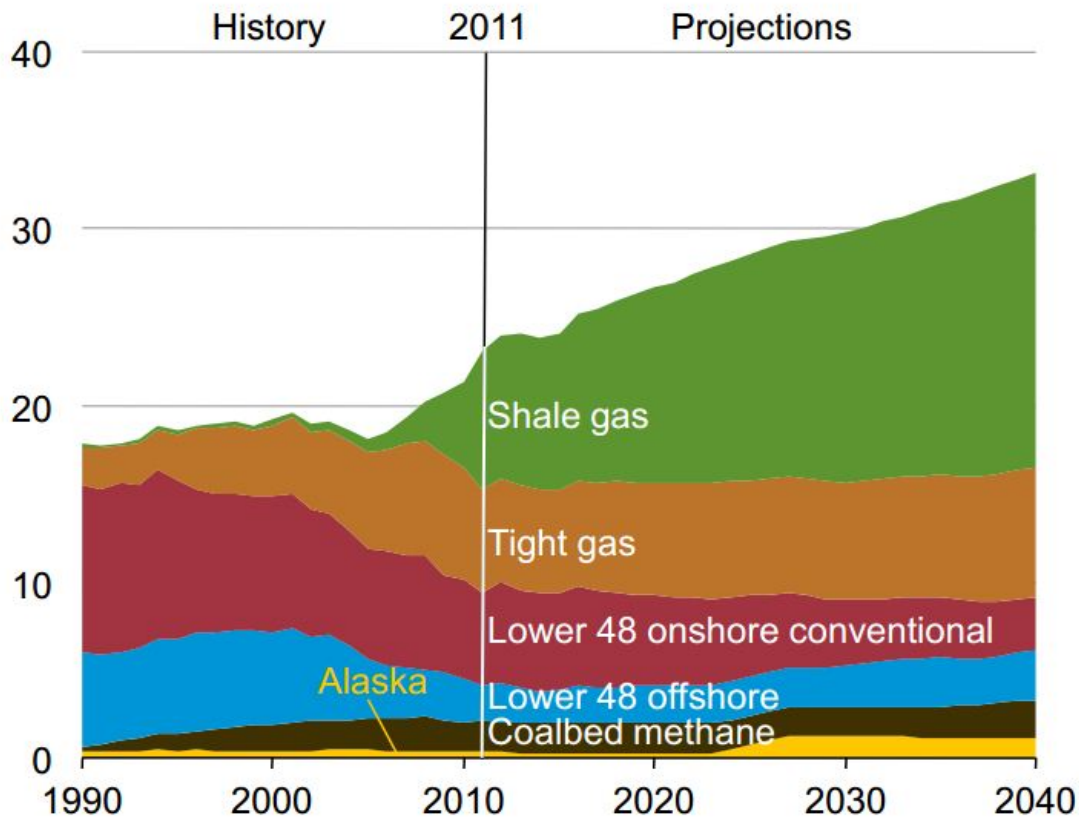
⁵⁰ Data is extracted from EIA's U.S. Crude Oil, Natural Gas, and NG Liquids Proved Reserves report from August 2012, in which the latest data is from 2011.

⁵¹ 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>

and the share of shale gas production in the EI region rose to 80% in 2010, compared to 29% in 2008.⁵²

Exhibit 10: U.S. Dry Natural Gas Production by Source 1990 – 2040 (TCF)



Source: EIA AEO2013

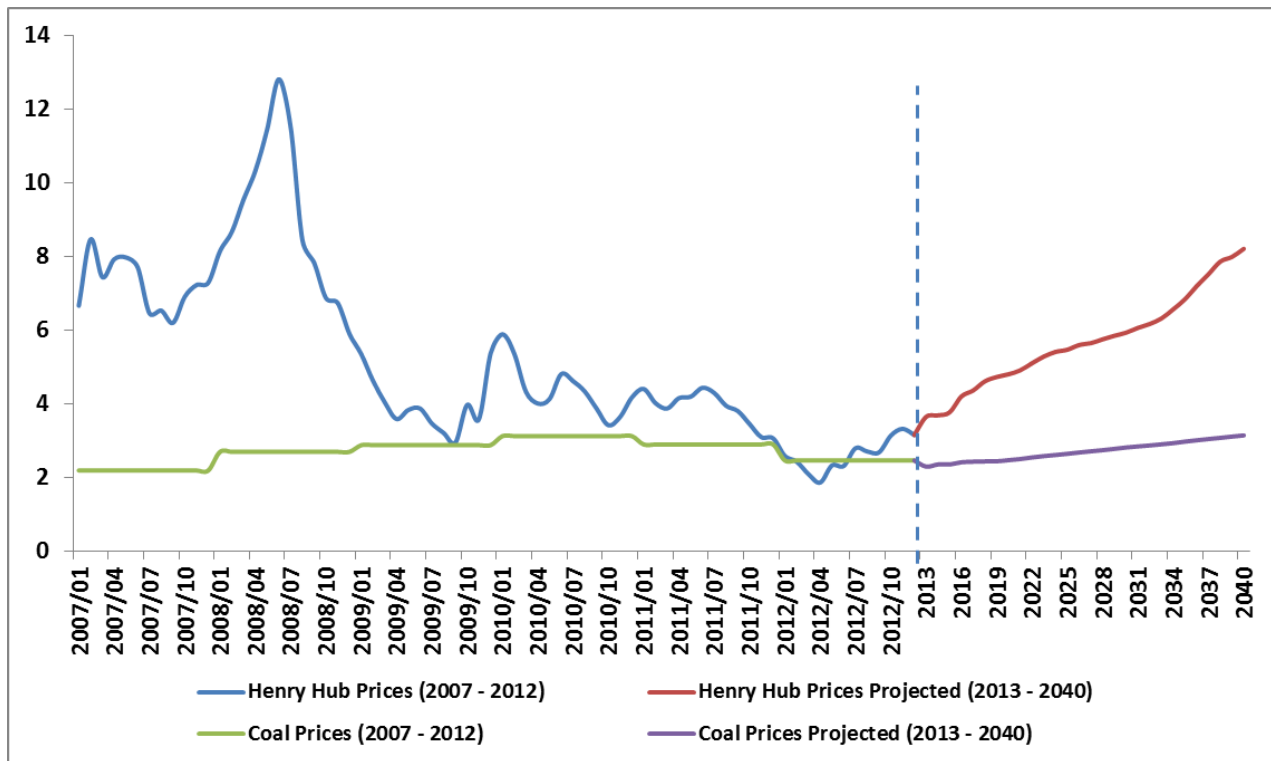
3.3.2 Natural gas prices

The sharp increase in shale gas development within the EI has resulted in both lower wellhead prices and lower basis differentials from the locally sourced gas—both of which are already strongly influencing the landscape of the power generation industry in the EI, and nationally. Natural gas prices have decreased dramatically since the peak of \$12.8/MMBtu in June 2008, with Henry Hub prices dipping below \$2.50/MMBtu from April to June in 2012 before recovering to the \$4/MMBtu range more recently.

Exhibit 11 shows the sharp decrease in monthly natural gas spot prices since 2007, and EIA's forecast of a gradual recovery of annual gas prices in the long term. While natural gas prices have experienced strong volatility, coal prices are projected to remain stable in the future, with much less volatility than gas prices.

⁵² EIA, Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays, July 2011.

Exhibit 11: Historical and Forecasted Gas and Coal Prices (2010\$/MMBtu)



Source: EIA AEO2013; EIA Annual Energy Review

3.3.3 Impact of low gas prices on existing plants

Within the EI, approximately 13% of total generation shifted from coal-fired to gas-fired sources from 2008 to 2012. By 2012, generation from coal-fired sources decreased to 42%, and natural gas generation increased to 29%.⁵³ This increase in production from gas power plants is a direct result of the lower gas prices (due to increased shale gas production), which has resulted in lower dispatch for coal plants.

In addition to the general trend of fuel shifting from coal to gas, multiple plants have announced plans to switch their fuel supply from coal to gas (i.e., repowering). 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 2017.⁵⁴ Georgia power also announced in 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.⁵⁵

⁵³ In 2008, 55% of total power generation was from coal-fired sources and the share of gas-fired generating resources was 16%. EIA, Survey-level Detail Data Files, State-level data, 2006 – 2012.

⁵⁴ 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>

⁵⁵ 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>

Growth in gas-fired generation is limited by three factors. First, the low load growth forecasts imply reduced need for new capacity in the near future. Second, with gas prices are slowly rising to the \$4/MMBtu range in 2013, dispatch from coal power plants has stabilized. Furthermore, Illinois Basin coal is experiencing an increase in popularity, with the widespread installation of pollution control retrofits that are able to reduce sulfur emissions from Illinois Basin coal, which has high sulfur content.⁵⁶ Third, the development of new gas-fired capacity depends on the availability of pipeline infrastructure and capacity. In many regions within the EI, especially in the Northeast and Mid-Atlantic areas, there are infrastructure constraints, and electric-gas integration requires extensive cooperation and coordination between previously separated gas and electric sectors.

3.3.4 Impact of low gas prices on new plants

Installation of new coal-fired capacity is severely limited by low natural gas prices, with new gas plants being cheaper and faster to construct than coal plants. In order to assess the scale of the impact of low natural gas prices on new coal-fired plants, ICF evaluated the levelized costs of electricity based on cost and performance data from a variety of publicly available sources.⁵⁷ ICF calculated the levelized cost of electricity (LCOE) for a variety of generating technologies based on assumptions from publicly available sources: cost and performance data assumptions for capital costs (see Exhibit 7), heat rate, typical capacity, VOM, and FOM are from the National Energy Technology Laboratory (NETL); and financial assumptions⁵⁸ including capital charge rate and fuel costs projections from the EIA. For coal-fired plants without CCS, an additional 3% of capital charge rate has been applied to reflect risks associated with potential price imposed on carbon emissions (consistent with EIA assumptions). For the LCOE calculation with the inclusion of CCS, costs incurred by CO₂ removal system and CO₂ compression and drying system are included; however, costs associated with CO₂ transportation, storage and monitoring costs are not included.

When natural gas prices are low, levelized cost of electricity of a new NGCC plant is significantly lower than that of any type of coal-fired technologies—see Exhibit 12, which shows how the LCOE for gas plants increase with natural gas prices.

Exhibit 12 also depicts the LCOE for various coal power technologies with and without CCS. Coal prices are assumed to stay between \$2 and \$3 per MMBtu, while gas prices in this Exhibit range from \$3.0/MMBtu to over \$15/MMBtu (2011\$/MMBtu). Based on ICF's calculations, only when gas prices are higher than about \$11.5/MMBtu does the LCOE of combined cycle plants exceed the cost of SCPC plants without CCS. With the abundance of natural gas from shale plays, natural gas prices as high as \$10/MMBtu are unlikely; furthermore, according to the latest projections from EIA, natural gas prices are expected to reach the \$8/MMBtu range by 2040. Therefore, it is very unlikely that new standard coal power plants will be built (without CCS) if there are no gas infrastructure issues. As illustrated in the chart below, IGCC plants without CCS are significantly more costly than SCPC plants without CCS. However, when CCS is

⁵⁶ Wall Street Journal, In the Midwest, Coal Stages a Comeback.

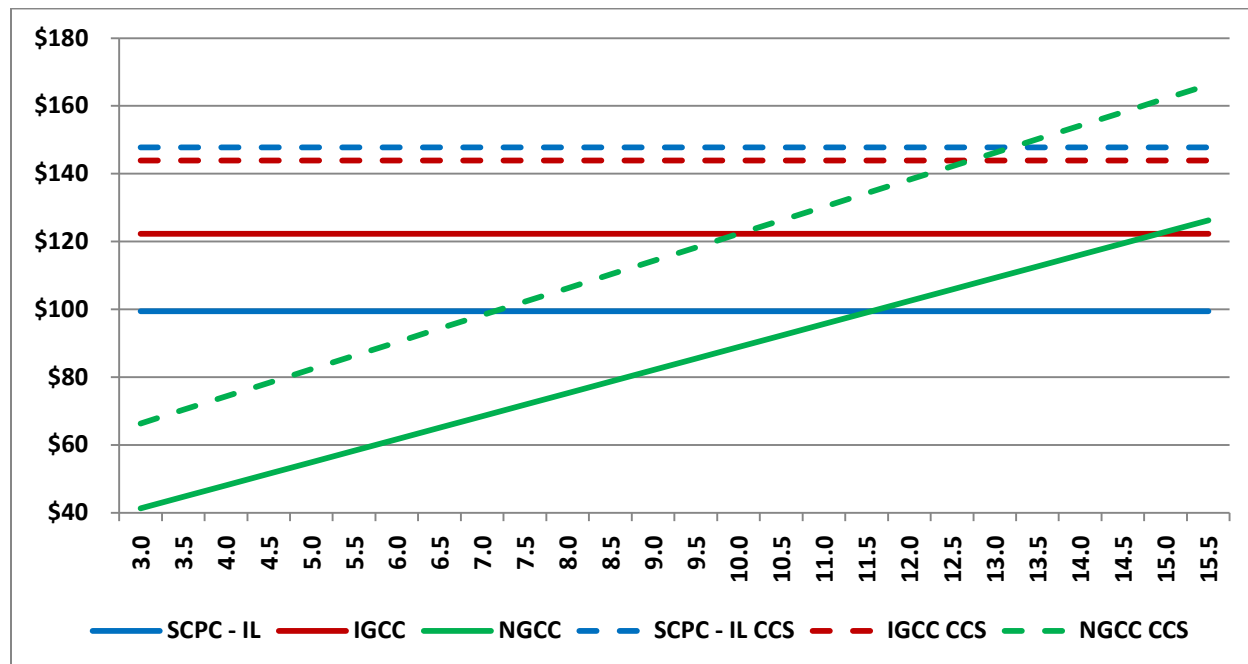
<http://online.wsj.com/article/SB10001424127887324582004578461324162944856.html>

⁵⁷ 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).

⁵⁸ For generating technologies without CCS, the capital charge rate (CCR) for coal-fired plants is 16.6% including an additional 3% accounting for carbon charges, and the CCR for natural gas-fired plants is 11.9%. For generating technologies with CCS, the CCR for coal-fired plants is 13.6%, and the CCR for natural gas-fired plants is still 11.9%.

incorporated, levelized costs of IGCC and SCPC plants are quite similar—although it is much higher than NGCC with CCS at low gas prices (less than about \$13/MMBtu).

Exhibit 12: Levelized Costs of Electricity from Coal and Gas Plants as a Function of Gas Prices (2011\$/MWh)⁵⁹



In summary, low natural gas prices put new coal-fired plants at a significant disadvantage, as it is difficult for new coal-fired plants with high levelized cost of electricity to compete with gas-fired generating technologies.

3.4 Impact of Electricity Markets and Reliability Planning Authorities

In addition to the aforementioned challenges facing the coal fleet, 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, five RTOs/ISOs function in the EI: ISO New England (ISO-NE), New York ISO (NYISO), PJM Interconnection (PJM), Southwest Power Pool (SPP) and Midcontinent ISO (MISO).

Within the EI, there is a mixture of traditionally regulated and competitive markets representing three different types of electricity market structures. Some regions in the EI, e.g., the Southeast, are served by traditionally regulated vertically integrated utilities exclusively, whereas other regions, e.g., MISO, employ market structures with a combination of competitive and partially competitive attributes. Competitive electricity markets were developed during the 1990s in order to reduce the cost of electricity on a large scale. Within the market areas of Midcontinent ISO and PJM Interconnection, individual state policies of implementing competitiveness in electricity

⁵⁹ Details about levelized costs of electricity calculation can be found in *Task 3: Assessing Coal Technologies* in the *Final Study Report*.

markets have resulted in the different mix of market participants including independent IPPs and vertically integrated utilities. The markets in the Northeast, under NYISO and ISO-NE, are competitive, with independent IPPs owning and developing the generation resources.

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 processes.

The following sections describe the structure and characteristics of competitive power markets in the EI, and highlight how current market conditions (low demand growth, excess supply, and low gas prices) are curtailing the development of new coal power plants. .

3.4.1 Competitive Electricity Markets

Competitive electricity markets rely on three classes of market products: energy, capacity, and ancillary services⁶⁰. 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 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.⁶¹

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

⁶⁰ 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.

⁶¹ PJM, PJM Manual 11: Energy & Ancillary Services Market Operations.
<http://www.pjm.com/~media/documents/manuals/m11.ashx>

a more dynamic tool to encourage the financing of the development of new resources when needed.

3.4.2 Varying Characteristics of Capacity Markets in the Eastern Interconnection

Although shared objectives and principles are in place, four of the RTOs/ISOs in the EI – ISO-NE, NYISO, PJM, and MISO – 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 13 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 years⁶², which can be problematic for the development of coal power plants, as they require long term commitments that capacity markets currently do not provide.

Exhibit 13: 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 Model (RPM)	Pricing Auctions	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 the cost of new entry (CONE) within a market area, as indicated in Exhibit 14. 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-NE, 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.⁶³ In MISO, the most recent estimate of CONE is based on costs associated with gas combined-cycle and gas combustion turbine generation resources.⁶⁴

Exhibit 14: CONE in the Eastern Interconnection

	Recent CONE (\$/kW-Year)
ISO New England	58.80
NYISO	175.80 – 388.32

⁶² 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

⁶³ PJM Manual 18: PJM Capacity Market. <http://www.pjm.com/~media/documents/manuals/m18.ashx>.

⁶⁴ 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>

*CONE will not be applicable in ISO New England from next auction cycle onward.

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 from \$32/kW-year to \$54/kW-year from 2010 to 2013.⁶⁵ 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).⁶⁶

According to projections from the EIA AEO2013⁶⁷, electricity prices from generation for the PJM region in 2018 would be \$54/MWh (2011\$/MWh). Based on ICF’s calculations⁶⁸, 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/MWh⁶⁹. As a result, capacity prices remain significantly below the required capacity revenue for all coal-fired generation options.⁷⁰ Volatility and the short-term nature of the capacity markets further exacerbate the problem.

3.4.3 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

⁶⁵ NYISO, Strip Auction Results. http://icap.nyiso.com/ucap/public/auc_view_strip_detail.do

⁶⁶ PJM, RPM Auction User Information. <http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx>

⁶⁷ EIA AEO2013, Electric Power Projections for EMM Regions, Reliability First Corporation/East, Reference Case.

⁶⁸ Details about levelized costs of electricity calculation can be found in *Task 3: Assessing Coal Technologies* in the *Final Study Report*.

⁶⁹ We did not account for forced outages in this conversion.

⁷⁰ 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.

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.

4 Opportunities for Coal-fired Capacity in the Eastern Interconnection

As described above, the coal-fired generating resources currently face an array of challenges: more stringent environmental regulations, competition from natural gas, and uncertainties surrounding the commercial availability of CCS technologies. However, as the landscape of generation mix is expected to alter in the United States, especially within the Eastern Interconnection, it is still valuable to take fuel diversity and fuel security into consideration. Coal-based power plants will likely have a role to play in such cases.

In addition to annual appropriations for CCS, Congress set aside \$3.4 billion from the American Recovery and Reinvestment Act for CCS research, development, and demonstration at the Department of Energy's Office of Fossil Energy. DOE has shifted the emphasis to the demonstration phase, and an influx of funding might accelerate the RD&D process of CCS technology.⁷¹ State incentives can also play an important role in advancing CCS technologies for power plant projects. Many states in the EI have been trying to encourage the development of new coal power plants in several ways. One of more common type of incentives for supporting new coal technologies is associated with supporting the development and commercial viability of CCS technology. Incentives that encourage and subsidize installation of CCS technologies could assist the development of advanced coal-fired plants (subject to economic limitations related to the price of natural gas).

Some states provide financial incentives (i.e. tax credits, tax abatements, and grants) for CCS projects directly. For instance, Montana provides property tax abatements for new investments in CCS equipment and facilities. Property tax abatements could equal up to 50% of the taxable value for facilities and equipment involved in capturing.⁷² The Illinois Finance Authority made an authorization to provide financial assistance to energy generating facilities, which provides up to \$300 million in bond funds for new gasification facilities with capacity greater than 400 MW that supports coal gasification or IGCC projects.⁷³ Mississippi sets the sales tax associated with the sales of CO₂ for geologic sequestration at 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.⁷⁴ These financial incentives are aimed at encouraging investments in CCS related power projects.

Another typical state-level incentive defines clean power generation technologies to include CCS, e.g. in technology portfolio standards. In states such as Florida, Michigan, and West Virginia, renewable portfolio standards expand the definition of "renewable energy" to include an option for CCS technologies. In this way, incentives designed for renewable energy resources can also support coal-fired plants with CCS technologies. Some states implement other

⁷¹ Congressional Research Service, Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy. <http://www.fas.org/sgp/crs/misc/R42496.pdf>

⁷² Mont. Code Ann. §15-24-31 Property Related Renewable Energy, New Energy Technology, and Clean Coal.

⁷³ 20 Ill. Comp. Stat. §605-332.

⁷⁴ Code Miss. Rules §35.IV.6.01 Sales and Use Tax: Utilities.

regulations for achieving a similar effect. Minnesota passed a regulation that excludes CO₂ that is captured from power plants and geologically sequestered, from the state's greenhouse gas reduction plan.⁷⁵

Some coal-bearing states have also implemented incentives for the coal-mining industry, particularly in states where coal mining still plays an important role in sustaining the economy. Arkansas, Illinois, Kentucky, Maryland, Ohio, Oklahoma, and Virginia provide tax credits of various amounts on each ton of coal mined, produced, or extracted within the state for the purpose of electricity generation.⁷⁶ These incentives issued by individual states aimed at sustaining the coal mining industry, while securing fuel sources for coal-fired power generating resources.

5 Conclusion

Regions in the Eastern U.S. have historically relied on coal-fired capacity to provide well over half of their generation. Although coal-fired units face an array of challenges, the existing base of coal-fired generating resources with pollution control equipment to limit emissions of criteria air pollutants will continue to play a significant role in the fuel mix within the EI for the foreseeable future. Current and future environmental regulations for limiting criteria pollutants, toxics, coal combustion residuals, and effluents will lead to significant deactivations and ultimately produce a future coal fleet consisting of larger, cleaner units.

A major uncertainty for these remaining coal generators will be what GHG performance standards regulations will be applied for existing plants, and whether they will face further constraints on NO_x emissions levels. Most of the retirements under the MATS regulations will be focused on smaller, uncontrolled units that are not economically viable (especially with low gas prices). ICF's internal projections indicate that nearly 85% of the total projected retired coal capacity will be in MISO, PJM, and SERC, which are all in the EI. As the MATS implementation deadline approaches, ICF projects over 50 GW of coal retirements nationally between 2013 and 2016, in addition to the approximately 12 GW retired during 2010 through 2012.

Environmental regulations concerning GHG emissions or climate change regulations that put a price on carbon emissions remains a wildcard for existing plants. President Obama in late June 2013 issued a Presidential Memorandum directing the EPA to reissue GHG performance standards for new sources, and to issue performance standards for existing sources for the first time. Details of the performance standards are being closely watched by both environmentalists and the power industry. Any requirement to add CCS to existing plants can result in significant retirements, especially since the technology remains expensive and is not yet fully commercialized.

Low gas prices over the last few years have reduced coal-based generation in the overall generation fuel mix (which has resulted in lower GHG emissions). However, as natural gas prices gradually climbed back up to the \$4/MMBtu level, existing coal units have regained some of their lost dispatch. While the low-sulfur coal resources in Central Appalachia have been challenged due to higher mining and environmental costs, Illinois basin and Power River Basin

⁷⁵ Minn. Stat. § 216H Greenhouse Gas Emissions.

⁷⁶ Details about statutes and regulations regarding coal-fired capacity and the coal mining industry can be found in *Task 6: Risks and Liabilities*.

coals are slowly staging a comeback. With the widespread installation of scrubbers, a major barrier to using higher sulfur Illinois Basin coal use is removed⁷⁷.

New coal-fired sources are primarily challenged by both environmental regulations (NSPS, in particular) and low natural gas prices. Additionally, low gas prices combined with low load growth, excess capacity, and increase in demand resources are not encouraging for developing new coal-fired capacity. The uncertain status of CCS technologies and the resulting high costs of electricity from new coal plants with CCS paint a challenging future. The DOE flagship CCS project, FutureGen, has experienced multiple delays and changes of scope and design. While the influx of funding might accelerate the CCS demonstration process, its prospects remain uncertain. Any state-level incentives to support coal mining and encourage the use of coal face an uphill battle in contending with these challenges.

⁷⁷ Wall Street Journal, In the Midwest, Coal Stages a Comeback.
<http://online.wsj.com/article/SB10001424127887324582004578461324162944856.html>



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