



Economic Impact Analysis for the Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units

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Economic Impact Analysis for the Review of Standards of Performance for Greenhouse Gas
Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility
Generating Units

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EXECUTIVE SUMMARY

ES.1 Introduction

EPA is revisiting several portions of the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units (EGUs), which was promulgated on October 23, 2015 (80 FR 64510). First, for newly constructed fossil fuel-fired electric utility steam generating units (both utility boilers and integrated gasification combined cycle (IGCC) units), EPA proposes to revise the best system of emissions reduction (BSER) to be the most efficient demonstrated steam cycle (i.e., supercritical steam conditions for large units and best available subcritical steam conditions for small units)¹ in combination with the best operating practices, in lieu of partial CCS, in light of the high costs and limited geographic availability of CCS. Based on the proposed revisions to the BSER, EPA is proposing to establish revised (i.e., higher) emission rates as the standards of performance for large and small units. Further, for fossil fuel-fired electric utility steam generating units that undertake reconstruction, because the standards for reconstructed sources are also based on best available efficiency technology, EPA is proposing to revise those standards to consist of higher emission rates for large and small units to be consistent with the standards for newly constructed EGUs. In addition, while EPA is not proposing to revise the BSER identified in the 2015 Rule for fossil fuel-fired electric utility steam generating units that undertake large modifications (i.e., modifications² that result in an increase in hourly emissions of more than 10 percent), EPA proposes to revise the maximally stringent standards³ to be consistent with the proposed revised standards for new and reconstructed EGUs.

Additionally, EPA proposes minor amendments to the applicability criteria for combined heat and power (CHP) and non-fossil EGUs to reflect the coverage intended in the 2015 final

¹ A subcritical EGU operates at pressures where water first boils and is then converted to superheated steam. A supercritical steam generator operates at pressures in excess of the critical pressure of water and heats water to produce superheated steam without boiling. Note: the term “EGU” is intended to refer to the affected facility (also referred to as the affected “source” or “unit”).

² Under 40 CFR 60.14(h), a modification of an existing electric utility steam generating unit is defined as a physical change or change in the method of operation of the unit that increases the maximum hourly emissions of any regulated pollutant above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

³ The maximally stringent standard for modified EGUs is the numeric standard for reconstructed EGUs, even if the emission rate based on best annual performance is lower than that numeric standard.

rule. EPA is not proposing to amend and is not reopening the standards of performance for newly constructed or reconstructed stationary combustion turbines.

A summary of the 2015 rule standards and the proposed standards are included in Table ES-1 below. Table ES-1 only includes the MWh-gross numeric standards; corresponding standards based on MWh-net output basis appears in the preamble accompanying this analysis.

This proposed rule is not anticipated to have an annual effect on the economy of \$100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local or tribal governments or communities and is therefore not an “economically significant rule” as defined by Executive Order (EO) 12866. However, EPA has prepared an Economic Impact Analysis to provide an analysis of the potential impacts of this action.

ES.2 Key Findings of the Economic Analysis

Clean Air Act (CAA) Section 111(b) requires that the new source performance standards (NSPS) be reviewed every eight years. As a result, this rulemaking’s analysis is primarily focused on projected impacts within the current eight-year NSPS timeframe. As explained in detail in this document, energy market data and projections support the conclusion that even in the absence of this proposal, expected economic conditions will lead electricity generators to choose new generation technologies that meet the 2015 standards and the proposed standards without the need for additional post-combustion controls.

The modeling of the electricity sector EPA performed for this rule using the Integrated Planning Model (IPM) projects that, even under the emissions limits included in this proposal, new fossil fuel-fired capacity constructed through 2026 and the years following is expected to be natural gas capacity. Applicable standards for this new capacity are not subject to the changes proposed in this action. Therefore, a baseline, which would include the current and numerically more stringent 2015 standards being amended by this proposal, would yield the same modeling result as the policy case. Additional analysis of data from the Annual Energy Outlook (AEO) issued by the U.S. Energy Information Administration (EIA) also shows that the technology of

choice for new generation is not expected to be coal-fired units⁴ due to current and projected market conditions. Accordingly, this analysis does not anticipate that any costs or benefits will result from the proposed amended standards provided utilities and project directors make choices related to new generation that are consistent with the choices forecasted by EPA and EIA modeling. Because we expect that few new EGU units will choose coal-fired generation due to expected economic conditions this proposed change in the standard will not affect the emissions profile of these units, resulting in negligible changes in GHG emissions over the analysis period. Additionally, based on historical precedent, EPA anticipates few covered units will trigger the NSPS reconstruction or modification provisions in the period of analysis. This analysis reflects the best data available to EPA at the time the modeling was conducted. As with any modeling of future projections, many of the inputs are uncertain. In this context, notable uncertainties, in the future, include the cost of fuels, the cost to operate existing power plants, the cost to construct and operate new power plants, infrastructure, demand, and policies affecting the electric power sector. The modeling conducted for this economic impact analysis is based on estimates of these variables, which were derived from the data currently available to EPA. However, future realizations could deviate from these expectations as a result of changes in wholesale electricity markets, federal policy intervention, including mechanisms to incorporate value for onsite fuel storage, or substantial shifts in energy prices. The results presented in this economic impact analysis are not a prediction of what will happen, but rather a projection describing how this proposed regulatory action may affect electricity sector outcomes in the absence of unexpected shocks. The results of this economic impact analysis should be viewed in that context.

⁴ The applicability of these standards includes all fossil fuel-fired steam generating units. This includes natural gas and oil-fired steam generating units as well as coal-based integrated gasification combined cycle units. However, EGUs burning either natural gas or oil would likely use combustion turbines due to lower capital and operating costs. This action does not propose changes to the standards for combustion turbines.

Table ES-1. Summary of 2015 Final Standards and Proposed Standards for Affected EGUs

Affected EGU	2015 Final Standard	Proposed Standard
Newly Constructed Fossil Fuel-Fired Steam Generating Units	1,400 lb CO ₂ /MWh-gross	1. 1,900 lb CO ₂ /MWh-gross for sources with heat input > 2,000 MMBtu/h. OR 2. 2,000 lb CO ₂ /MWh-gross for sources with heat input ≤ 2,000 MMBtu/h. OR 3. 2,200 lb CO ₂ /MWh-gross for coal refuse-fired sources
Modified Fossil Fuel-Fired Steam Generating Units	Sources making modifications resulting in an increase in CO ₂ hourly emissions of more than 10 percent are required to meet a unit-specific emission limit determined by the unit's best historical annual CO ₂ emission rate (from 2002 to the date of the modification); the emission limit will be no more stringent than: 1. 1,800 lb CO ₂ /MWh-gross for sources with heat input > 2,000 MMBtu/h. OR 2. 2,000 lb CO ₂ /MWh-gross for sources with heat input ≤ 2,000 MMBtu/h.	Sources making modifications resulting in an increase in CO ₂ hourly emissions of more than 10 percent are required to meet a unit-specific emission limit determined by the unit's best historical annual CO ₂ emission rate (from 2002 to the date of the modification); the emission limit will be no more stringent than: 1. 1,900 lb CO ₂ /MWh-gross (for sources with heat input > 2,000 MMBtu/h). OR 2. <i>No proposed change for sources with heat input ≤ 2,000 MMBtu/h</i> OR 3. 2,200 lb CO ₂ /MWh-gross for coal refuse-fired sources
Reconstructed Fossil Fuel-Fired Steam Generating Units	1. 1,800 lb CO ₂ /MWh-gross for sources with heat input > 2,000 MMBtu/h. OR 2. 2,000 lb CO ₂ /MWh-gross for sources with heat input ≤ 2,000 MMBtu/h.	1. 1,900 lb CO ₂ /MWh-gross for sources with heat input > 2,000 MMBtu/h. OR 2. <i>No proposed change for sources with heat input ≤ 2,000 MMBtu/h</i> OR 3. 2,200 lb CO ₂ /MWh-gross for coal refuse-fired sources
Newly Constructed and Reconstructed Natural Gas-Fired Stationary Combustion Turbines	1. 1,000 lb CO ₂ /MWh-gross or 1,030 lb CO ₂ /MWh-net for base load natural gas-fired units. 2. 120 lb CO ₂ /MMBtu for non-base load natural gas-fired units. 3. 120 to 160 lb CO ₂ /MMBtu for multi-fuel-fired units.	<i>No proposed change.</i>

CHAPTER 1: INTRODUCTION AND BACKGROUND

1.1 Introduction

In this action, the U.S. Environmental Protection Agency (EPA) is proposing to amend emission limits for greenhouse gases (GHGs), specifically carbon dioxide (CO₂), emitted from fossil fuel-fired Electricity Generating Units (EGUs). This action proposes to amend the Final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units finalized October 23, 2015 (80 FR 64510). This document presents the expected economic impacts of this revision. This chapter contains background information on this proposed rule and an outline of the chapters in this report.

1.2 Legal, Scientific, and Economic Basis for this Rulemaking

1.2.1 *Statutory Requirement*

Clean Air Act (CAA) section 111, which Congress enacted as part of the 1970 Clean Air Act Amendments, establishes mechanisms for controlling emissions of air pollutants from stationary sources. This provision requires EPA to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds “causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.”¹ EPA has listed more than 60 stationary source categories under this provision.² Once EPA lists a source category, EPA must, under CAA section 111(b)(1)(B), establish “standards of performance” for emissions of air pollutants from new sources in the source categories.³ A “new source” is “any stationary source, the construction or modification of which is commenced after,” in general, final standards applicable to that source are promulgated or, if earlier, proposed.⁴ These standards are known as new source performance standards (NSPS), and they are national requirements that apply directly to the sources subject to them.

“Standards of performance” are defined under CAA section 111(a)(1) as standards for emissions that reflect the emission limitation achievable from the “best system of emission

¹ CAA §111(b)(1)(A).

² See 40 CFR 60 subparts Cb – OOOO.

³ CAA §111(b)(1)(B), 111(a)(1).

⁴ CAA section 111(a)(2).

reduction,” considering costs and other factors, that “the Administrator determines has been adequately demonstrated.”

1.2.2 Market Failure

Many regulations are promulgated to correct market failures, which otherwise lead to a suboptimal allocation of resources within the free market. Air quality and pollution control regulations address “negative externalities” whereby the market does not internalize the full opportunity cost of production borne by society as public goods such as air quality are unpriced.

While recognizing that optimal social level of pollution may not be zero, GHG emissions impose costs on society, such as negative health and welfare impacts, that are not reflected in the market price of the goods produced through the polluting process. For this regulatory action the good produced is electricity. If a fossil fuel-fired electricity producer pollutes the atmosphere when it generates electricity, this cost will be borne not by the polluting firm but by society as a whole, thus the producer is imposing a negative externality, or a social cost of emissions. The equilibrium market price of electricity may fail to incorporate the full opportunity cost to society of generating electricity. Consequently, absent a regulation on emissions, the EGUs will not internalize the social cost of emissions and social costs will be higher as a result. This regulation will work towards addressing this market failure by causing affected EGUs to begin to internalize the negative externality associated with CO₂ emissions.

1.2.3 Regulatory Analysis

This proposed rule is not anticipated to have an annual effect on the economy of \$100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local or tribal governments or communities and is therefore not an “economically significant rule” as defined by Executive Order (EO) 12866. However, EPA has prepared an Economic Impact Analysis. The economic impact analysis provides an analysis of the potential impacts of this action.

This economic impact analysis addresses the potential costs and benefits of the new, modified, and reconstructed source emission limits that are amended by this proposed action. As described in Chapter 3, EPA does not anticipate that any costs or quantified benefits will result from the proposed amended standards for new sources provided utilities and project directors

make choices related to new generation that are consistent with the choices projected by EPA and EIA modeling. However, if future economic conditions (e.g., natural gas prices) differ from these projections and utilities construct new coal-fired units, there could be some compliance cost savings and increased emissions as discussed in Chapter 2. Chapter 4 describes EPA’s conclusions for the proposed changes for reconstruction and modification provisions. EPA has historically been notified of few modifications or reconstructions under the NSPS provisions and, as such, anticipates few covered units will trigger the NSPS reconstruction or modification provisions in the period of analysis. As a result, we do not anticipate significant costs or benefits as a result of this proposal.

1.3 Background for the Analysis

1.3.1 Summary of the Proposed Amendments

EPA is revisiting several portions of the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units (EGUs), which was promulgated on October 23, 2015 (80 FR 64510). First, for newly constructed fossil fuel-fired electric utility steam generating units (both utility boilers and integrated gasification combined cycle (IGCC) units), EPA proposes to revise the BSER to be the most efficient demonstrated steam cycle (i.e., supercritical steam conditions for large units and best available subcritical steam conditions for small units)⁵ in combination with the best operating practices, instead of partial CCS, in light of the high costs and limited geographic availability of CCS. Based on the proposed revisions to the BSER, EPA is proposing to establish revised (i.e., higher) emission rates as the standards of performance for large and small units. Further, for fossil fuel-fired electric utility steam generating units that undertake reconstruction, because the standards for reconstructed sources are also based on best available efficiency technology, EPA is proposing to revise those standards to consist of higher emission rates for large and small units to be consistent with the standards for newly constructed EGUs. In addition, while EPA is not proposing to revise the BSER identified in the 2015 Rule (which is

⁵ A subcritical EGU operates at pressures where water first boils and is then converted to superheated steam. A supercritical steam generator operates at pressures in excess of the critical pressure of water and heats water to produce superheated steam without boiling. Note: the term “EGU” is intended to refer to the affected facility (also referred to as the affected “source” or “unit”).

based on the individual units best demonstrated performance) for fossil fuel-fired electric utility steam generating units that undertake large modifications (i.e., modifications⁶ that result in an increase in hourly emissions of more than 10 percent) EPA proposes to revise the maximally stringent standards⁷ to be consistent with the proposed revised standards for new and reconstructed EGUs.

Additionally, EPA proposes minor amendments to the applicability criteria for combined heat and power (CHP) and non-fossil EGUs to reflect the original intended coverage. EPA is not proposing to amend the standards of performance for newly constructed or reconstructed stationary combustion turbines.

A summary of the 2015 final standards and proposed standards for each affected EGU are shown in Table 1-1. The standards in Table 1-1 are shown on a MWh-gross basis; these standards on a MWh-net basis are available in the preamble accompanying this action.

⁶ Under 40 CFR 60.14(h), a modification of an existing electric utility steam generating unit is defined as a physical change or change in the method of operation of the unit that increases the maximum hourly emissions of any regulated pollutant above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

⁷ The maximally stringent standard for modified EGUs is the numeric standard for reconstructed EGUs, even if the emission rate based on best annual performance is lower than that numeric standard.

Table 1-1. Summary of 2015 Final Standards and Proposed Standards for Affected EGUs

Affected EGU	2015 Final Standard	Proposed Standard
Newly Constructed Fossil Fuel-Fired Steam Generating Units	1,400 lb CO ₂ /MWh-gross	1. 1,900 lb CO ₂ /MWh-gross for sources with heat input > 2,000 MMBtu/h. OR 2. 2,000 lb CO ₂ /MWh-gross for sources with heat input ≤ 2,000 MMBtu/h. OR 3. 2,200 lb CO ₂ /MWh-gross for coal refuse-fired sources
Modified Fossil Fuel-Fired Steam Generating Units	Sources making modifications resulting in an increase in CO ₂ hourly emissions of more than 10 percent are required to meet a unit-specific emission limit determined by the unit's best historical annual CO ₂ emission rate (from 2002 to the date of the modification); the emission limit will be no more stringent than: 1. 1,800 lb CO ₂ /MWh-gross for sources with heat input > 2,000 MMBtu/h. OR 2. 2,000 lb CO ₂ /MWh-gross for sources with heat input ≤ 2,000 MMBtu/h.	Sources making modifications resulting in an increase in CO ₂ hourly emissions of more than 10 percent are required to meet a unit-specific emission limit determined by the unit's best historical annual CO ₂ emission rate (from 2002 to the date of the modification); the emission limit will be no more stringent than: 1. 1,900 lb CO ₂ /MWh-gross (for sources with heat input > 2,000 MMBtu/h. OR 2. <i>No proposed change for sources with heat input ≤ 2,000 MMBtu/h</i> OR 3. 2,200 lb CO ₂ /MWh-gross) for coal refuse-fired sources
Reconstructed Fossil Fuel-Fired Steam Generating Units	1. 1,800 lb CO ₂ /MWh-gross for sources with heat input > 2,000 MMBtu/h. OR 2. 2,000 lb CO ₂ /MWh-gross for sources with heat input ≤ 2,000 MMBtu/h.	1. 1,900 lb CO ₂ /MWh-gross for sources with heat input > 2,000 MMBtu/h. OR 2. <i>No proposed change for sources with heat input ≤ 2,000 MMBtu/h</i> OR 3. 2,200 lb CO ₂ /MWh-gross for coal refuse-fired sources
Newly Constructed and Reconstructed Natural Gas-Fired Stationary Combustion Turbines	1. 1,000 lb CO ₂ /MWh-gross or 1,030 lb CO ₂ /MWh-net for base load natural gas-fired units. 2. 120 lb CO ₂ /MMBtu for non-base load natural gas-fired units. 3. 120 to 160 lb CO ₂ /MMBtu for multi-fuel-fired units.	<i>No proposed change.</i>

1.3.2 Regulated Pollutant

The purpose of this CAA section 111(b) rule is to address CO₂ emissions from fossil fuel-fired power plants in the U.S. because they are the largest domestic stationary source of emissions of carbon dioxide (CO₂). CO₂ is the most prevalent of the greenhouse gases (GHG), which are air pollutants that EPA previously determined endangers public health and welfare through their contribution to climate change.

1.3.3 Definition of Affected Sources

EPA identified the applicability requirements for the 40 CFR part 60, subpart TTTT standards in the 2015 rulemaking, and the Agency is not proposing to revise or reopen those requirements, except as noted below. For convenience, the applicability requirements are as follows: In general, EPA refers to fossil fuel-fired electric generating units that would be subject to a CAA section 111 emission standard as “affected” or “covered” sources, units, facilities, or simply as EGUs. An EGU is any fossil fuel-fired electric utility steam generating unit (i.e., a utility boiler or IGCC unit) or combustion turbine (in either simple cycle or combined cycle configuration) that meets the applicability criteria. To be considered an affected EGU under 40 CFR part 60, subpart TTTT, the unit must both: (1) be capable of combusting more than 250 million British thermal units per hour (MMBtu/h) (260 gigajoules per hour (GJ/h)) of heat input of fossil fuel (either alone or in combination with any other fuel);⁸ and (2) serve a generator capable of supplying more than 25 megawatts (MW) net to a utility distribution system (i.e., for sale to the grid).⁹ However, 40 CFR part 60, subpart TTTT includes applicability exemptions for certain EGUs. For information on these exemptions, please see the preamble accompanying this proposal.

The CAA defines a new or modified source for purposes of a given regulation as any stationary source that commences construction or modification after the publication of the proposed regulation. A modification is any physical change in, or change in the method of operation of an existing source that increases the amount of any air pollutant emitted to which a

⁸ We refer to the capability to combust 250 MMBtu/h of fossil fuel as the "base load rating criterion." Note that 250 MMBtu/h is equivalent to 73 MW or 260 GJ/h heat input.

⁹ We refer to the capability to supply 25 MW net to the grid as the "total electric sales criterion."

standard applies.¹⁰ provided that an existing source is considered a new source if it undertakes a reconstruction.

EPA is proposing several changes to the applicability requirements. First, EPA is proposing to change the non-fossil EGU exemption capable of “combusting 50 percent or more non-fossil fuel” to capable of “*deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating*” (emphasis added). This amendment is consistent with the original intent of the 2015 NSPS to cover only fossil fuel EGUs and would assure that solar thermal EGUs with natural gas backup burners, which are similar to other types of non-fossil fuel units in that most of their energy is derived from non-fossil fuel sources, are not subject to the requirements of 40 CFR part 60, subpart TTTT. The definition of base load rating would also be amended to include the heat input from non-combustion sources (e.g., solar thermal). Next, the design efficiency of an EGU is used to determine the electric sales applicability threshold. 40 CFR part 60, subpart TTTT currently allows the use of three methods for determining the design efficiency. To reduce compliance burden, EPA is proposing to allow alternative methods as approved by the Administrator on a case-by-case basis. Finally, to avoid potential double counting of electric sales, EPA is proposing that for CHP units determining net electric sales, purchased power of the host facility would be determined based on the percentage of thermal power provided to the host facility by the specific CHP facility.

These proposed changes are primarily intended to clarify the applicability of the NSPS. For clarity in this analysis, we note that the applicability requirements include all fossil fuel-fired steam generating units. This includes natural gas and oil-fired steam generating units as well as coal-based integrated gasification combined cycle units. However, new EGUs burning either natural gas or oil would likely use combustion turbines due to lower capital and operating costs. Therefore, the proposed standards will primarily apply to coal-fired EGUs.

1.3.4 Baseline and Years of Analysis

The baseline for this analysis is a business-as-usual scenario that would be expected under current market and regulatory conditions in the absence of these proposed amendments. The existing Final Standards of Performance for Greenhouse Gas Emissions from New,

¹⁰ 40 CFR 60.2.

Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units went into effect October 23, 2015, and currently any new, modified, or reconstructed sources would be expected to comply with these standards. New source standards under section 111(b) must be established prior to any existing source standards under section 111(d), consistent with CAA section 111(b)(A). Accordingly, the baseline for this analysis does not include 111(d) standards for Electric Generating Units; specifically, the baseline for this analysis does not include the 2015 111(d) rulemaking known as the Clean Power Plan or any proposed 111(d) standards. State rules that have been finalized and/or approved by a state's legislature or environmental agency, as well as other final federal rules are incorporated in the baseline.

The impacts of the proposed standards are evaluated relative to this baseline. From a potential impacts perspective, the most important proposed change is to the standard for newly constructed fossil fuel-fired steam generating units. Because the proposed standard is less stringent than the current standard for newly constructed fossil fuel-fired units, this analysis evaluates whether units unable to meet the current final standard, but able to meet the proposed standard, would be projected for construction under the proposed standard. That is, the analysis evaluates a scenario assuming the proposed changes are in effect, and observes whether any EGUs affected by the amended standards would be constructed. This analysis is focused on coal-fired units, as they are the generation technology primarily affected by the proposed standards.

To characterize forecasted new electric generating units, EPA conducted analysis and modeling using both EPA's Power Sector Modeling Platform version 6 of the Integrated Planning Model and several editions of the Annual Energy Outlook (AEO). As noted above EPA's modeling does not include the 2015 111(d) standard for EGUs, known as the Clean Power Plan. The base case includes state rules that have been finalized and/or approved by a state's legislature or environmental agency as well as final federal rules, except for the 2015 CAA section 111(d) standard for EGUs. Additional information on IPM and the base case used in this analysis appears in Chapter 3.

CAA section 111(b) requires that the NSPS be reviewed every eight years. Accordingly, this analysis evaluates impacts through the year 2026 and all estimates are presented in 2016 dollars.

1.4 Electric Power Sector Profile

For an overview of the industry affected by this rule, please see the Regulatory Impact Analysis accompanying the Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program and available in docket EPA-HQ-OAR-2017-0355.

1.5 Changes in Emissions

As discussed in more detail in Chapter 3 of this analysis, EPA anticipates that the proposed changes in newly constructed fossil fuel-fired steam generating units will result in negligible changes in GHG emissions over the analysis period. We expect that new EGU units will not likely choose coal-fired generation due to expected economic conditions, and thus this proposed change in the standard will not affect the emissions profile of these units. Additionally, based on historical precedent, EPA anticipates few covered units will trigger the NSPS reconstruction or modification provisions in the period of analysis.

1.6 Organization of the Economic Impact Analysis

This report presents EPA's analysis of the potential benefits, costs, and other economic effects of the proposed standards. This economic impact analysis includes the following chapters:

- Chapter 2, Analysis of Illustrative Scenarios for New Sources, includes additional analyses examining the potential cost-savings for new sources.
- Chapter 3, Costs, Economic, and Energy Impacts of the New Source Standards, describes impacts of the rule for new sources.
- Chapter 4, Modified and Reconstructed Sources, describes the potential impacts of the standards for modified and reconstructed sources.

CHAPTER 2: ANALYSIS OF ILLUSTRATIVE SCENARIOS FOR NEW SOURCES

2.1 Synopsis

The next chapter of this analysis presents EPA's analysis and projections from EIA's AEO that support the conclusion that the proposed EGU New Source Standards will result in negligible costs and benefits in the period of analysis.¹ EPA recognizes that this conclusion is based on underlying expected economic conditions (e.g., fuel prices) and assumptions about considerations investors would weigh in deciding whether to build new coal-fired power plants. This chapter presents illustrative analyses that consider the changes in costs and emissions that would result if an operator were to choose to build a new coal-fired unit that is compliant with the proposed standard relative to a new coal-fired unit that is compliant with the current standard.

While the analysis in Chapter 3 focuses on national-level conditions, the analysis in this chapter explores the potential impacts to individual investments. The analysis in this chapter finds that under the conditions in which the future economic competitiveness of new coal-fired units relative to other new generation technologies no longer apply, or in specific situations where an operator chooses to build a coal-fired unit, the proposed standards will result in a cost savings for operators as well as forgone benefits. The assumptions regarding the future economic competitiveness of new coal-fired units relative to other new generation technologies could change as a result of changes in wholesale electricity markets, federal policy intervention including mechanisms to incorporate value for onsite fuel storage, or substantial shifts in energy prices.

2.2 Option Value and the Proposed New Source Standards

Firms operating in the power sector have a set of options available to address increases in electricity demand, such as increasing the utilization of existing generating capacity, implementing energy efficiency programs to mitigate demand growth, or investing in new generating capacity. Within the category of investing in new generating capacity firms are able to select amongst a set of generating technologies and energy sources. Uncertainty about future conditions that could impact the profitability of these different investment options means that

¹ The standards for modified and reconstructed sources are addressed in Chapter 4.

retaining flexibility to react to future conditions and choose the most profitable investments has value to firms. The value associated with retaining flexibility and being able to select the most profitable investments in the future is referred to as “option value.”² This proposal does not impose a direct cost on firms by requiring them to take a specific action, but rather, the proposed standards restore option value to firms by allowing the construction of new fossil steam EGUs with an emissions rate above the 2015 final standard. For example, the emission rate of 1,400 lb CO₂/MWh-gross was based on a BSER of SCPC with partial CCS. Thus, in order to comply with the 2015 standard currently in effect an operator would likely need to have CCS on a new coal-fired facility. The proposed emission rate is based on a BSER of a SCPC or subcritical unit with optimal operation and as a result the selection of a new generation technology is less restricted than under the 2015 final standard. While the discussion in Chapter 3 shows that it is highly unlikely that over the analysis period there will be a sufficient increase in relative fuel prices (e.g., natural gas prices relative to coal) to make a typical new coal-fired EGU cost-competitive with available substitutes such as NGCC, to the extent that new coal-fired EGUs are constructed, the proposed rule allows for a wider variety of generation technologies that meet the applicable standard than the 2015 final standard.

2.3 Comparison of Cost and Emissions from Generation Technologies

As discussed in Chapter 3, NGCC units are on average expected to be more economical to build and operate than new coal units. Even so, an operator may find it desirable to construct a new coal-fired EGU for the purpose of diversifying its generation fleet across fuels to hedge against uncertainty in fuel markets, or other scenario-specific considerations as discussed above. To the extent that new coal-fired EGUs are constructed, there are differences in costs and emissions associated with building units compliant with the 2015 final standard of 1,400 lb CO₂/MWh-gross and the proposed standards. This section examines the estimated change in emissions as well as potential cost-savings and forgone benefits based on an analysis of illustrative facilities of each heat input category identified in the proposed standards.

Under the proposal, coal refuse-fired facilities would be required to meet a standard of 2,200 lb/MWh-gross. If these facilities are constructed, their CO₂ emissions will be greater than

² We refer the interested reader to Dixit and Pindyck (1994) and Trigeorgis (1996) for more information on the concept of option value in the context of firms’ investment choices.

the emissions estimated here for both heat input categories, assuming a corresponding capacity size. Additionally, it can also be expected that their sulfur dioxide (SO₂) and nitrogen oxide (NO_x) emissions will be greater than those estimated here given the lower efficiency of coal refuse-fired EGUs as well as expected differences in refuse coal as compared to the bituminous coal used for these calculations. To the extent that new coal refuse-fired EGUs are constructed, there will also be environmental benefits of reclaiming coal refuse piles that are not considered here.

Only the direct emissions of CO₂, SO₂, and NO_x are considered in this illustrative exercise. Other air and water pollutants emitted by these technologies and emissions from the extraction and transport of the fuels used by these technologies are not considered. However, while it is assumed that any facilities burning coal are in compliance with current utility regulations, such as the Mercury and Air Toxics Standards (MATS), direct PM and mercury emissions could be slightly lower under the proposed standard as a result of the increase in generation when operating a CCS system. Additionally, in some cases, NO_x emissions from fossil-fired sources are subject to mass limits on the total NO_x emissions across EGUs (e.g. in states subject to the Cross-State Air Pollution Rule annual NO_x program), so these emissions may in some cases be offset by NO_x increases from other generating units.

2.3.1 LCOE and Emissions Comparison for Sources with Heat Input > 2,000 MMBtu/h

If coal-fired facilities with a heat input greater than 2,000 MMBtu/h are constructed, assuming a facility of 600MW_{net} capacity operating at an 85 percent capacity factor, this action will result in a cost savings of approximately \$17 per MWh as compared to a SCPC facility with partial CCS, as would be required under the 2015 standard.³

With the removal of partial CCS given the higher CO₂ standard under this proposal, there would be an increase in emissions of CO₂ as well as SO₂. There is an estimated annual increase in CO₂ emissions of 1.1 million short tons per year, and an increase of 500 short tons of SO₂ per year. In this illustrative example, SO₂ emissions are primarily controlled by a traditional SO₂ scrubber. In the partial CCS case, a secondary SO₂ scrubber is necessary to remove the remaining SO₂ in the slip stream prior to the carbon capture technology. For generation without

³ Note that this calculation does not exactly match the numbers presented in Table 2-1 due to rounding.

CCS there is no secondary SO₂ scrubber and net SO₂ emissions are therefore higher. NO_x emissions are slightly lower, but remain relatively constant. The difference in NO_x emissions can be attributed to the change in generation when operating a CCS system. NO_x emissions do not need to be removed prior to the carbon capture technology and can pass through the equipment prior to being released to the atmosphere. The criteria pollutant NO_x NSPS is the controlling standard and is on a lb/MWh-gross basis. The addition of partial CCS adds both additional steam and electrical auxiliary load and the net efficiency is reduced at approximately twice the rate as the gross efficiency. The change in the relative net to gross efficiency results in a relatively small net increase in NO_x emissions. Due to rounding, these changes are not always shown numerically.

Table 2-1. Illustrative LCOE and Emissions Profiles for New Coal-Fired Generating Units of 600 MW_{net} Capacity

	SCPC+Partial CCS (1,400 lb/MWh-gross)		SCPC (1,900 lb/MWh-gross)	
LCOE (2016\$/MWh)	\$99		\$82	
	Emissions (short tons/year)	Emissions Rate (lb/MWh-net)	Emissions (short tons/year)	Emissions Rate (lb/MWh-net)
SO₂	1,200	0.61	1,700	0.83
NO_x	1,500	0.75	1,500	0.74
CO₂	3.0 million	1,500	4.1 million	2,000

Note: Units assumed to be of 600 MW_{net} capacity. Emissions from NETL 2015. To estimate an emissions rate of 1,900 lb CO₂/MWh-gross the efficiency was adjusted while holding all other values constant. Values rounded to two significant digits. Emissions characteristics are based on, and thus consistent with the cost and performance assumptions of the illustrative units described in the LCOE analysis in Section 2.7 (i.e. these are base load units run at 85 percent capacity factor, all coal units are assumed to be using bituminous coal with a sulfur content of 2.8 percent dry, etc.). The tons of emissions are estimated for a coal-fired facility with partial CCS that achieves the gross-output standard of 1,400 lb/MWh and presented in this table on a net output basis. For the post-combustion CCS system assumed in the SCPC case, acidic gases (e.g., SO₂, HCl) need to be scrubbed to very low levels prior to going into the CCS system to avoid degradation of the solvent. Therefore, SO₂ emissions are lower in the case of the SCPC unit with partial CCS. Under the proposal, coal refuse-fired facilities would be required to meet a standard of 2,200 lb/MWh-gross. If these facilities are constructed, their CO₂ emissions will be greater than the emissions estimated here. Additionally, it can also be expected that their SO₂ and NO_x emissions will be greater than those estimated here given the lower efficiency of coal refuse-fired EGUs as well as expected differences in refuse coal as compared to the bituminous coal used for these calculations.

2.3.2 LCOE and Emissions Comparison for Sources with Heat Inputs $\leq 2,000$ MMBtu/h

The results are similar for facilities with a heat input less than 2,000 MMBtu/h. To the extent these smaller facilities are constructed, this action will result in a cost savings of approximately \$19/MWh.

With the removal of partial CCS given the higher CO₂ standard under this proposal, there is an increase in emissions of CO₂ as well as SO₂. NO_x emissions decrease. Annually there is an estimated increase in CO₂ emissions of 240,000 short tons per year, and an increase of 110 short tons of SO₂ per year. NO_x emissions decrease by 10 short tons per year. The dynamics driving these changes in emissions are the same as those described in Section 2.3.1.

Table 2-2. Illustrative LCOE and Emissions Profiles for New Coal-Fired Generating Units of 150 MWnet Capacity.

	Subcritical PC+Partial CCS (1,400 lb/MWh-gross)		Subcritical PC (2,000 lb/MWh-gross)	
LCOE (2016\$/MWh)	\$100		\$81	
	Emissions (short tons/year)	Emissions Rate (lb/MWh-net)	Emissions (short tons/year)	Emissions Rate (lb/MWh-net)
SO ₂	310	0.61	420	0.88
NO _x	380	0.75	370	0.74
CO ₂	0.76 million	1,500	1.0 million	2,100

Note: Units assumed to be of 150 MWnet capacity. Emissions from NETL 2015. To estimate an emissions rate of 2,000 lb CO₂/MWh-gross the efficiency was adjusted while holding all other values constant. Values rounded to two significant digits. Emissions characteristics are based on, and thus consistent with the cost and performance assumptions of the illustrative units described in the LCOE analysis in Section 2.7 (i.e. these are base load units run at 85 percent capacity factor, all coal units are assumed to be using bituminous coal with a sulfur content of 2.8 percent dry, etc.). The tons of emissions are estimated for a coal-fired facility with partial CCS that achieves the gross-output standard of 1,400 lb/MWh and presented in this table on a net output basis. For the post-combustion CCS system assumed in the SCPC case, acidic gases (e.g., SO₂, HCl) need to be scrubbed to very low levels prior to going into the CCS system to avoid degradation of the solvent. Therefore, SO₂ emissions are lower in the case of the SCPC unit with partial CCS. Under the proposal, coal refuse-fired facilities would be required to meet a standard of 2,200 lb/MWh-gross. If these facilities are constructed, their CO₂ emissions will be greater than the emissions estimated here. Additionally, it can also be expected that their SO₂ and NO_x emissions will be greater than those estimated here given the lower efficiency of coal refuse-fired EGUs as well as expected differences in refuse coal as compared to the bituminous coal used for these calculations.

2.4 Discussion of Health and Climate Impacts from Generation Technologies

This rule is designed to set emission limits for carbon dioxide (CO₂), thereby limiting potential increases in future emissions and atmospheric CO₂ concentrations. As discussed in

Chapter 3, the U.S. Environmental Protection Agency (EPA) projects this proposed rule will not result in any significant CO₂ emission increases relative to baseline conditions, due to baseline market conditions. However, to the extent that new coal-fired facilities are constructed, a BSER coal facility under the proposed standard would have higher CO₂ and SO₂ emissions, but slightly lower NO_x emissions, than a BSER facility under the 2015 final standards. Table 2-1 and Table 2-2 above show the estimated change in emissions for coal-fired generation under the proposed standard rather than the 2015 standard. Only the direct emissions of CO₂, SO₂, and NO_x are considered in this illustrative exercise.

2.4.1 Climate Change Impacts

In 2009, the EPA Administrator found that elevated concentrations of greenhouse gases in the atmosphere may reasonably be anticipated both to endanger public health and to endanger public welfare.⁴ It is these adverse impacts that necessitate EPA regulation of GHGs from EGU sources. To the extent that new coal-fired facilities are constructed, a BSER coal facility under the proposed standard would have higher CO₂ emissions than a BSER facility under the 2015 final standards. We do not attempt to quantify the impacts of these increased emissions or economic value of these impacts. Since 2009, other science assessments suggest accelerating trends.⁵

2.4.2 Ancillary Health Impacts of SO₂ and NO_x Emissions

As noted above, this proposed rule is designed to affect emissions of CO₂ from the electricity sector and is anticipated to result in negligible emissions changes over the baseline, thereby negligible health effects. However, to the extent that new coal-fired power plants are constructed this action will also influence the level of emissions of certain pollutants in the atmosphere that adversely affect human health; these include directly emitted PM_{2.5} as well as SO₂ and NO_x, which are both precursors to ambient PM_{2.5}. NO_x emissions are also a precursor

⁴ “Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,” 74 Fed. Reg. 66,496 (Dec. 15, 2009) (“Endangerment Finding”).

⁵ Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: Climate Change Impacts in the United States: The Third National Climate Assessment. U.S. Global Change Research Program, 841 pp. doi:10.7930/J0Z31WJ2; and USGCRP, 2017: Climate Science Special Report: Fourth National Climate Assessment, Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 470 pp., doi: 10.7930/J0J964J6.

in the formation of ambient ground-level ozone. We do not attempt to quantify the number or economic value of these air pollution-related effects and instead characterize the adverse effects of these two pollutants in qualitative terms.

Exposure to PM_{2.5} and ozone is associated with adverse human health impacts including premature death and chronic and acute illnesses. A large and growing body of evidence, including toxicological, controlled human exposure and epidemiological studies have associated both chronic (i.e., years-long) and acute (day-to-day) exposure with a host of adverse effects (U.S. EPA 2009, U.S. EPA 2013). Health effects associated with exposure to PM_{2.5} include premature mortality for adults and infants, cardiovascular morbidity such as heart attacks and hospital admissions, and respiratory morbidity such as asthma attacks, bronchitis, hospital and emergency room visits, work loss days, restricted activity days, and respiratory symptoms. Health effects associated with exposure to ozone include premature mortality and respiratory morbidity such as hospital admissions, emergency room visits, and school loss days.

Both SO₂ and NO_x can also directly affect human health. For example, ambient concentrations of SO₂ are associated with respiratory symptoms in children, emergency department visits, and hospitalizations for respiratory conditions. Finally, SO₂ and NO_x emissions would also result in other human welfare (non-health) improvements including improvements in ecosystem services. SO₂ and NO_x emissions can adversely impact vegetation and ecosystems through acidic deposition and nutrient enrichment, and can affect certain manmade materials, visibility, and climate (U.S. EPA 2009, U.S. EPA 2016, U.S. EPA 2017). The number of cases of air pollution-related health and welfare effects that result from changes in SO₂ and NO_x emissions will ultimately depend on the location of those changes. For a full discussion of the human health, ecosystem and other benefits of reducing SO₂ and NO_x emissions from power sector sources, please refer to the Regulatory Impact Analysis accompanying the Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program and available in docket EPA-HQ-OAR-2017-0355.

2.6 References

- 40 CFR Chapter I [EPA–HQ–OAR–2009–0171; FRL–9091–8] RIN 2060–ZA14, “Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act,” Federal Register / Vol. 74, No. 239 / Tuesday, December 15, 2009 / Rules and Regulations.
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CHAPTER 3: COSTS, ECONOMIC, AND ENERGY IMPACTS OF THE PROPOSED NEW SOURCE STANDARDS

3.1 Synopsis

This chapter reports the compliance cost, economic, and energy impact analyses performed for the proposed EGU New Source GHG standards. To determine the potential impacts from this action EPA analyzed and assessed potential scenarios and outcomes using a detailed power sector model, supplemented by other government projections for the power sector.

The primary finding of this assessment is that this proposed amendment to the 2015 111(b) standards for EGUs is anticipated to result in the construction of, at most, few new, unplanned coal-fired units. The analysis period is defined as through 2026 to reflect that CAA section 111(b) requires that the NSPS be reviewed every eight years. This conclusion is based on EPA power sector modeling projections and an analysis of EIA power sector modeling projections discussed in this chapter. This analysis reflects the best data available to EPA at the time the modeling was conducted. As with any modeling of future projections, many of the inputs are uncertain. In this context, notable uncertainties, in the future, include the cost of fuels, the cost to operate existing power plants, the cost to construct and operate new power plants, infrastructure, demand, and policies affecting the electric power sector. The modeling conducted for this economic impact analysis is based on estimates of these variables, which were derived from the data currently available to EPA. However, future realizations could deviate from these expectations as a result of changes in wholesale electricity markets, federal policy intervention, including mechanisms to incorporate value for onsite fuel storage, or substantial shifts in energy prices. The results presented in this economic impact analysis are not a prediction of what will happen, but rather a projection describing how this proposed regulatory action may affect electricity sector outcomes in the absence of unexpected shocks. The results of this economic impact analysis should be viewed in that context.

EPA's conclusion remains robust beyond the analysis period (including past 2035 in EPA baseline modeling projections) and across a range of alternative potential market and technical scenarios that influence power sector investment decisions. As a result, the proposed amended

EGU New Source GHG Standards are not expected to change GHG emissions for newly constructed EGUs, and are anticipated to yield no costs, benefits, economic impacts, or energy impacts on the electricity sector or society. While EPA projects, at most, few new conventional coal-fired EGUs to be built under the proposed policy, this chapter presents an analysis of the project-level costs of building new coal-fired capacity with and without CCS and compares those costs to an alternative generation technology, Natural Gas Combined Cycle (NGCC). This analysis of project-level costs shows that building a coal facility compliant with a standard of 1,400 lbs CO₂/MWh, as finalized in 2015, is more costly than a supercritical or subcritical facility that meets the emission standards proposed in this action. Comparing the costs of supercritical and subcritical coal facilities with an NGCC facility demonstrates that under standard assumptions coal is not the most cost-effective generation technology, supporting the finding that few new coal-fired EGUs would be built in the analysis period.

3.2 Requirements of the Proposed GHG EGU NSPS

In this action, EPA is proposing amendments to the 2015 rule's provisions for newly constructed fossil fuel-fired electric utility steam generating units (both utility boilers and IGCC units). EPA proposes to amend its previous determination that the BSER for such newly constructed fossil steam units is partial CCS. Instead, EPA proposes to find that the BSER is the most efficient demonstrated steam cycle, i.e., supercritical steam conditions for large units and best available subcritical steam conditions for small units, in combination with the best operating practices. Unless stated otherwise, EPA's use of supercritical steam conditions encompasses both ultra-supercritical and advanced ultra-supercritical steam conditions. There is a thermodynamic definition of ultra-supercritical or advanced ultra-supercritical steam conditions and they are terms used to define a subset of supercritical steam conditions with higher temperatures and pressures.¹

A separate standard is established for coal refuse-fired generation due to the inherently higher emission rates of EGUs burning coal refuse and the environmental benefits of remediating coal refuse piles. The discussion that follows refers to conventional coal and coal with CCS. For

¹ Supercritical, ultra-supercritical, and advanced ultra-supercritical steam generators use the same general steam generating unit design. The primary difference is that different materials are required to withstand the higher temperatures of ultra-supercritical and advanced ultra-supercritical steam conditions.

the purposes of this analysis, conventional coal refers to coal-fired EGUs not equipped with CCS technology. As discussed later in this chapter, we believe the construction and operation of coal-fired facilities is similar regardless of the fuel source, and thus the conclusions drawn from the power sector modeling and an analysis of levelized cost of electricity generation can apply broadly to all forms of coal-fired generation. EPA is not revising its view in the 2015 rule that natural gas co-firing and IGCC are alternate control technologies, but not the BSER.

3.3 Power Sector Modeling Framework Overview

3.3.1 Integrated Planning Model

IPM is a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior and examine prospective air pollution control policies throughout the contiguous United States for the entire electric power system.² It provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. EPA has used IPM for over two decades to better understand power sector behavior into the future and to evaluate the economic and emission impacts of prospective environmental policies. EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions summarized here as well as all other model assumptions and inputs.³ The model also incorporates a detailed representation of the fossil fuel supply system that is used to forecast equilibrium fuel prices for natural gas and coal.

EPA has used IPM extensively over the past two decades to analyze options for reducing power sector emissions. Previously, the model has been used to forecast the costs, emission changes, and power sector impacts for the Clean Air Interstate Rule (CAIR), Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standards (MATS), and the Clean Power Plan (CPP). IPM has also been used to estimate the air pollution reductions and power sector

² For more detail on past peer reviews, updates, and improvements to IPM, see model documentation available at <https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling>

impacts of water and waste regulations affecting EGUs, including Cooling Water Intakes (316(b)) Rule, Disposal of Coal Combustion Residuals from Electric Utilities (CCR) and Steam Electric Effluent Limitation Guidelines (ELG).

The model and EPA's input assumptions undergo periodic formal peer review. The rulemaking process also provides opportunity for expert review and comment by a variety of stakeholders, including owners and operators of capacity in the electricity sector that is represented by the model, public interest groups, and other developers of U.S. electricity sector models. The feedback that the Agency receives provides a highly-detailed review of key input assumptions, model representation, and modeling results.

In June 2018 EPA updated its application of IPM to version 6. This update incorporates important structural improvements, as well as routine data updates, and reflects a robust representation of electricity generation and related fuel markets. More information on these updates is available in the comprehensive model documentation, which is available on EPA's website.⁴ (U.S. EPA 2018)

3.3.2 Energy Information Administration Annual Energy Outlook

In addition to using IPM, EPA has examined modeling results from several editions of the Annual Energy Outlook (AEO) from the U.S. Energy Information Administration (EIA). AEO provides long-term modeling projections of the domestic energy market. To produce the AEO, EIA employs the National Energy Modeling System (NEMS), an energy-economy modeling system of the United States. According to EIA, "NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics." (EIA 2009)

The Electricity Market Module of NEMS produces projections of power sector behavior that minimize the cost of meeting electricity demand subject to the sector's inherent constraints,

⁴ See Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, available at: <https://www.epa.gov/airmarkets/epas-power-sector-modeling-platform-v6-using-ipm>

including the availability of existing generation capacity, transmission capacity and cost, cost of utility and nonutility technologies, expected load shapes, fuel markets, regulations, and other factors. (EIA 2018b)

3.4 Analysis of Future Generating Capacity

3.4.1 EPA Power Sector Modeling Projections

To evaluate the potential impacts of this proposal, EPA conducted modeling using EPA's Power Sector Modeling Platform version 6 of the Integrated Planning Model. This modeling demonstrates that all new sources covered by this proposal that are currently planned or projected to be constructed are capable of meeting the proposed standard without taking any additional action. Therefore, it was not necessary to evaluate additional IPM scenarios.⁵ This modeling scenario does not apply any standards of performance under section 111(b) or 111(d) of the CAA for CO₂ emissions from new or existing sources, including the 2015 Clean Power Plan 111(d) standards of performance.⁶ Furthermore, this scenario does not include any Federally-enforceable regulations related to CO₂ emissions that would inhibit construction of new coal-fired steam generators. This allows for an assessment of the relative economics of new power plants, absent any 111 requirements.⁷ This analysis reflects the best data available to EPA at the time the modeling was conducted. As with any modeling of future projections, many of the inputs are uncertain. In this context, notable uncertainties include the cost of fuels, the cost to operate existing power plants, the cost to construct and operate new power plants, infrastructure, demand, and policies affecting the electric power sector. The modeling conducted for this economic impact analysis is based on estimates of these variables, which were derived from the data currently available to EPA. However, future realizations of these characteristics may deviate from expectations. The results presented in this economic impact analysis are not a prediction of

⁵ Note for completeness, in the following section, we also examine several scenarios across a range of economic conditions using AEO results.

⁶ This scenario is equivalent to the "illustrative CPP repeal" scenario modeled as part of the Regulatory Impact Analysis accompanying the Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program and available in docket EPA-HQ-OAR-2017-0355.

⁷ Note that new, non-peaking fossil fuel-fired plants face additional risks associated with a potential cost on future CO₂ emissions, which EIA addresses by increasing the cost of debt and equity for new coal plants. EPA extends this treatment of risk to new combined cycle plants in the modeling.

what will happen, but rather a projection describing how this proposed regulatory action may affect electricity sector outcomes in the absence of unexpected shocks. The results of this economic impact analysis should be viewed in that context.

Table 3-1 reports the projected unplanned capacity additions under this scenario.⁸ These projected additions are based on prevailing economics and are not constrained by federally-enforceable CO₂ requirements. The modeling demonstrates that coal-fired steam generation capacity is not projected to be built in the absence of any CO₂ emissions standards. Prevailing economics favor the construction of other types of capacity that are able to meet future demand at a lower overall cost.⁹ This finding is supported both by recent activity in the power sector as well as the analysis of AEO projections presented in the following section. A further discussion of the costs of coal-fired generation relative to NGCC appears in Section 3.7.

Table 3-1. IPM Unplanned Cumulative Capacity Additions (GW)

Capacity Type	2025	2030	2035
Conventional Coal	0.0	0.0	0.0
Coal w/ CCS	0.0	0.0	0.0
Natural Gas Combined Cycle (NGCC)	1.4	9.2	34.5
Natural Gas Combustion Turbine (Natural Gas CT)	7.3	11.5	26.3
Non-Hydro Renewables	81.6	133.5	136.0
Hydro	8.0	8.7	9.3
Nuclear	0.0	0.0	0.0
Total	98.3	163.0	206.2

Additional model projections, including the detailed modeling output files for the scenario described in this chapter are available in the docket for this action and on EPA’s website. Projections are also extensively discussed in the Regulatory Impact Analysis accompanying the Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program and available in docket EPA-HQ-OAR-2017-0355 (see “CPP Repeal” scenario in Chapter 3).

⁸ The detailed modeling output files for the scenario described in this chapter are available in the docket and on EPA’s website, which include additional data and information, including results from additional model run years.

⁹ The GHG emission rate for new natural gas combined cycle units in the modeling is below the 2015 111(b) standard.

3.4.2 Analysis of AEO Projections

Several years of AEO projection data were examined for this analysis. AEO projections are released annually and, in general, the AEO reference case represents existing policies and regulations influencing the power sector and “assumes trend improvement in known technologies along with a view of economic and demographic trends reflecting the current views of leading economic forecasters and demographers” (EIA 2018a). The 2015 111(b) standards for new, modified, and reconstructed power plants are explicitly included in the AEO 2018 reference case and all side cases. AEO 2018 requires that “new coal technologies must have at least 30% carbon capture to ensure the ability to meet the standard of 1,400 lb CO₂/MWh. New coal plants without CCS technology cannot be built.” (EIA 2018b) Consistent with the IPM modeling described above, the AEO 2018 reference case does not include the 2015 111(d) standard for existing power plants, known as the Clean Power Plan.

Because AEO 2018 requires compliance with the existing 2015 111(b) standards, information from both AEO 2018 and AEO 2015 was examined. AEO 2015 is the most recent edition of the AEO where compliance with the 2015 new source standards was not required, making this the most recent analysis where new coal facilities without CCS could be projected in the AEO for construction. Additionally, as discussed below, market conditions for coal-fired capacity are expected to be more favorable to new coal units in AEO 2015 than in AEO 2018 as natural gas was more expensive relative to the price of coal.

3.4.2.1 AEO Reference Case

Table 3-2 reports the cumulative unplanned capacity additions projected in the AEO 2018 and AEO 2015 reference cases. Unplanned capacity additions are those that the model projects to be built in response to forecast economic conditions, such as fuel prices and demand growth. AEO 2018 cannot construct conventional coal-fired capacity, reflecting the current regulatory standard from the 2015 111(b) rule. AEO 2018 also does not project the construction of any coal-fired capacity with CCS, which would be compliant with the 2015 111(b) rule. AEO 2015 explicitly projects CCS-equipped coal capacity, which in AEO 2015 was assumed to result from existing federal, state, and local incentives for the technology and has been removed from later editions of the AEO as it was later determined unlikely to occur.

AEO 2015 allows for the construction of conventional coal, which would be able to meet the emission standards in this proposal. However, AEO 2015 does not project the construction of new conventional coal facilities. This suggests that the revised new source standards included in this proposal would not result in conventional coal-fired steam generating units being projected for construction that would not be constructed under the existing standards, consistent with the findings of the IPM analysis. These general findings are also consistent with trends in the power sector, discussed in Section 3.6.

Table 3-2. Cumulative Unplanned Capacity Additions (GW) from AEO 2018 and AEO 2015 Reference Cases

Capacity Type	AEO 2018 Reference Case			AEO 2015 Reference Case		
	2025	2030	2035	2025	2030	2035
Conventional Coal	<i>Not available in model</i>			0.0	0.0	0.0
Coal with CCS	0.0	0.0	0.0	0.3	0.3	0.3
Natural Gas CC	12.9	28.5	40.8	17.3	39.0	60.5
Natural Gas CT	13.0	19.9	26.5	8.5	16.8	26.1
Nuclear	0.0	0.0	0.0	0.0	0.1	0.6
Renewables	49.0	62.2	106.1	7.1	13.4	26.6
Distributed Generation	0.9	1.5	2.3	1.1	1.7	2.4
Total	75.7	112.1	175.8	34.3	71.4	116.5

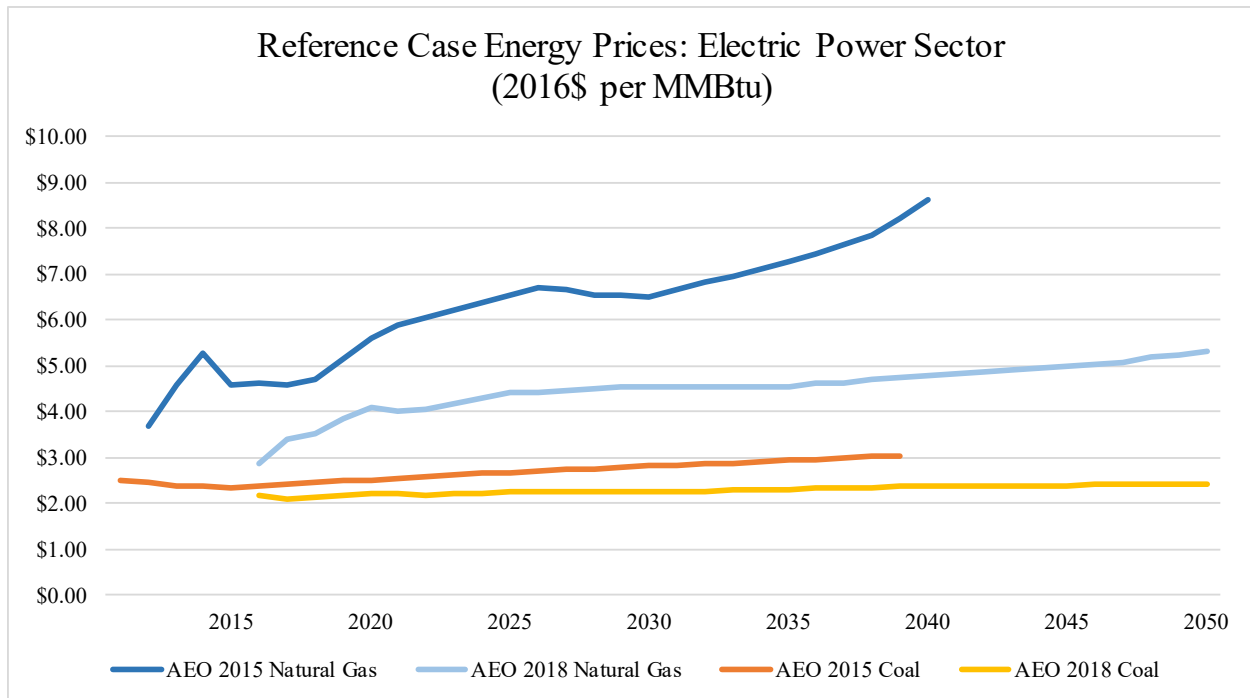
Note: The sum of the table values in each column may not match total due to rounding.

Source: EIA Annual Energy Outlook 2018 and 2015. Table A9. AEO 2018 Reference case values exclude battery storage additions, which were not modeled in AEO2015.

Table 3-2 shows significantly more unplanned capacity additions are added in AEO 2018 than in AEO 2015. While overall capacity in the electric sector remains relatively similar between the years of AEO data, there are more retirements and new additions in AEO 2018. This increase in retirements is driven predominately by increased retirements of coal and nuclear generation, driven by low natural gas prices and coal retirements resulting from compliance with the Mercury and Air Toxics Standards (MATS) (EIA 2018a). AEO 2015 also assumed that MATS went into effect in 2016, however with different electricity market conditions and fuel prices, AEO 2015 projected fewer retirements and so less generating capacity was added (EIA 2015a). New capacity is added primarily through renewable energy generation. The cost of solar photovoltaic generation continues to decrease and favorable state and federal policies further encourage the adoption of solar technology, as well as other renewables.

Between AEO 2015 and AEO 2018 there were not significant changes in the capital costs of constructing coal- or natural gas-fired units, therefore changes in the favorability of market conditions for coal between these two AEO editions will be primarily driven by differences in projected future fuel prices. Expected future fuel prices are important in decision-making regarding future capacity additions, which is discussed in further detail in Section 3.5. Figure 3-1 shows the projected price of coal and natural gas in the Reference Case for both AEO 2018 and 2015. While coal prices remain relatively consistent between the two AEO editions, natural gas prices are consistently lower in AEO 2018. This suggests that conditions for the construction of new coal facilities were more favorable in AEO 2015 as natural gas was more expensive relative to the cost of coal. Additionally, AEO 2015 allows for the construction of conventional coal facilities, while AEO 2018 requires coal to have at least partial CCS to be compliant with the 2015 111(b) standards. Even under the more favorable conditions in AEO 2015, new conventional coal is not projected for construction. These projections hold in most reasonably anticipated scenarios, although dramatic shifts in projected prices or significant changes in federal policy could result in different outcomes.

Figure 3-1. AEO 2018 and 2015 Reference Case Projected Coal and Natural Gas Power Sector Delivered Prices (2016\$ per MMBtu).



3.4.2.2 AEO Alternative Scenarios

Table 3-3 below shows the projected unplanned cumulative capacity additions by 2025 across all of the AEO 2015 alternative scenarios, as well as the reference case. As discussed above, market conditions were more favorable for coal in AEO 2015 and AEO 2018 does not allow for projections of conventional coal at all as it is not compliant with the 2015 111(b) standards. The year 2025 was examined given its relationship to the NSPS 8-year review window. Across all of the alternative scenarios presented in AEO 2015, by 2025 there are no unplanned additions of conventional coal.¹⁰ Similarly, none of the AEO 2018 scenarios project additional coal with CCS capacity.

¹⁰ AEO 2015 projects an addition of unplanned coal-fired capacity from 2028 to 2035 in the high oil price scenario, though this addition is for coal-to-liquids (CTL) production. A small cumulative addition of 0.9 GW of unplanned coal capacity, in addition to the 0.3 GW of CCS-equipped coal is also forecast to be added from 2029 to 2035 in the high economic growth scenario. AEO 2018 does not forecast any unplanned capacity additions of coal-fired generation in any of the scenarios.

Table 3-3. AEO 2015 Reference Case and Alternative Scenario Projections of Unplanned Cumulative Capacity Additions by 2025, GW.

Capacity Type	Reference	High Growth	Low Growth	High Oil Price	Low Oil Price	High Oil and Gas Resource
Conventional Coal	0.0	0.0	0.0	0.0	0.0	0.0
Coal with CCS	0.3	0.3	0.3	0.3	0.3	0.3
Natural Gas CC	17.3	35.0	11.4	18.4	17.5	20.0
Natural Gas CT	8.5	17.3	6.0	9.1	10.8	20.3
Nuclear	0.0	0.4	0.0	0.2	0.0	0.0
Renewables	7.1	12.9	5.5	12.7	6.3	4.3
Distributed Generation	1.1	1.6	0.7	0.6	1.4	4.6
Total	34.3	67.5	23.9	41.2	36.3	49.6

Note: The AEO 2015 scenario definitions generally are:

- Reference: Real gross domestic product (GDP) grows at an average annual rate of 2.4% from 2013 to 2040. North Sea Brent crude oil prices rise to \$141/barrel (bbl) (2013 dollars) in 2040.
- High Economic Growth: Real GDP grows at an average annual rate of 2.9% from 2013 to 2040.
- Low Economic Growth: Real GDP grows at an average annual rate of 1.8% from 2013 to 2040.
- High Oil Price: Brent crude oil prices rise to \$252/bbl in 2040.
- Low Oil Price: Light, sweet (Brent) crude prices remain around \$52/bbl through 2017, then rise slowly to \$76/bbl in 2040.
- High Oil and Gas Resource: Estimate ultimate recovery per shale gas, tight gas, and tight oil well is 50% higher and well spacing is 50% closer. The estimate ultimate recovery for tight and shale wells increases by 1%/year more than the annual increase in the reference case. This case also includes 50% higher production from other gas resource.

For more information on the AEO 2015 scenarios, view the AEO 2015 report. Available at [https://www.eia.gov/outlooks/archive/aeo15/pdf/0383\(2015\).pdf](https://www.eia.gov/outlooks/archive/aeo15/pdf/0383(2015).pdf)

3.5 Power Sector Fuel Price Dynamics, Trends, and Projections

The expectations of future fuel prices play a key role in determining the overall cost competitiveness of conventional coal-fired units versus natural gas. While compliance with the proposed standard likely will not require post-combustion controls such as CCS, the overall competitiveness of coal with natural gas will determine if coal-fired capacity will be built.

The AEO alternative scenarios examine the effects of alternative fuel price projections. Table 3-4 compares the 2025 fuel prices in the AEO 2015 and AEO 2018 reference and alternative cases. Across all the scenarios, the relative difference between natural gas and coal prices was greater in AEO 2015 than in AEO 2018. As the price of natural gas falls relative to coal, it can be assumed that demand for natural gas will increase compared to that of coal. Given

that new conventional coal was not projected for construction in AEO 2015, it is reasonable to conclude that even if AEO 2018 allowed for the construction of conventional coal, conventional coal capacity would not be added given the lower natural gas price (relative to the price of coal) compared to that seen in AEO 2015.

Table 3-4. National Power Sector Delivered 2025 Fuel Prices by AEO Scenario (2016\$/MMBtu)

	Natural Gas Price	Steam Coal Price	Relative Difference
AEO 2015			
Reference Case	\$6.54	\$2.65	\$3.89
High Economic Growth	\$6.87	\$2.66	\$4.21
Low Economic Growth	\$6.18	\$2.62	\$3.56
High Oil Price	\$7.82	\$2.88	\$4.94
Low Oil Price	\$6.10	\$2.56	\$3.55
High Oil and Gas Resource	\$4.17	\$2.46	\$1.71
AEO 2018			
Reference Case	\$4.40	\$2.24	\$2.16
High Economic Growth	\$4.37	\$2.25	\$2.12
Low Economic Growth	\$4.25	\$2.22	\$2.03
High Oil Price	\$4.22	\$2.35	\$1.87
Low Oil Price	\$4.11	\$2.10	\$2.01
High Oil and Gas Resource	\$3.36	\$2.11	\$1.25
Low Oil and Gas Resource	\$6.64	\$2.41	\$4.23

Note: The AEO 2015 scenario definitions are summarized in Table 3-3.

For more information on the AEO 2015 scenarios, view the AEO 2015 report. Available at [https://www.eia.gov/outlooks/archive/aeo15/pdf/0383\(2015\).pdf](https://www.eia.gov/outlooks/archive/aeo15/pdf/0383(2015).pdf)

The AEO 2018 scenario definitions generally are:

- Reference: Real gross domestic product (GDP) grows at an average annual rate of 2.0% from 2017 to 2050. North Sea Brent crude oil prices rise to \$112/barrel (bbl) (2016 dollars) in 2050.
- High Economic Growth: Real GDP grows at an average annual rate of 2.6% from 2017 to 2050.
- Low Economic Growth: Real GDP grows at an average annual rate of 1.5% from 2017 to 2050.
- High Oil Price: Brent crude oil prices rise to \$225/bbl (2016 dollars) by 2050.
- Low Oil Price: Light, sweet (Brent) crude prices reach \$51/bbl (2016 dollars) by 2050.
- High Oil and Gas Resource: lower costs and higher resource availability allow for higher production at lower prices.
- Low Oil and Gas Resource: higher costs and lower resource availability result in lower production at higher costs. Note that this scenario was not included in AEO 2015.

For more information on the AEO 2018 scenarios, view the AEO 2018 report. Available at <https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf>

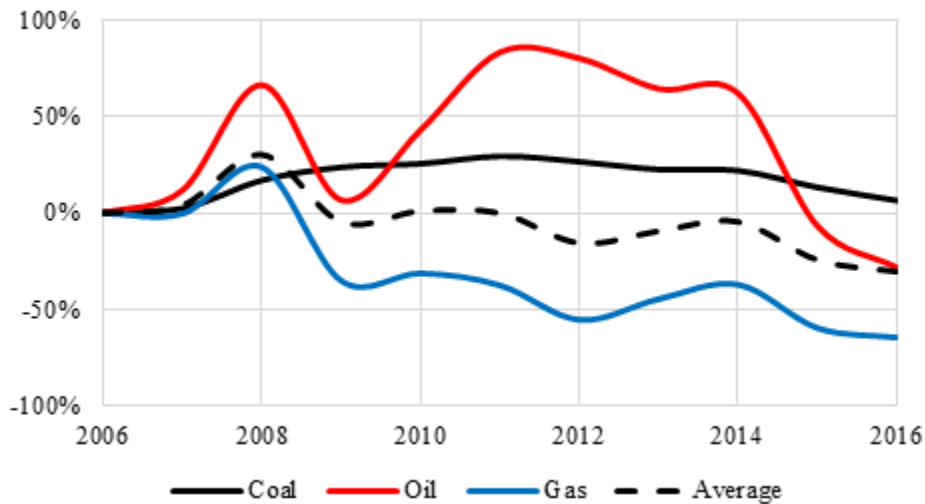
This downward movement in natural gas prices between AEO 2015 and 2018 follows trends in natural gas production. Current and projected natural gas prices are low, as a result of an increased supply. Advances in hydraulic fracturing and horizontal drilling techniques that

have opened new shale gas resources have resulted in a substantially increased supply of economically-recoverable natural gas. According to EIA, as of 2016 the U.S. has an estimated 324.3 trillion cubic feet (Tcf) of proved total natural gas reserves, approximately 200 Tcf of which is proved shale gas resources (EIA 2018d). Additionally, U.S. natural gas production in 2016 was the second-highest level recorded, down slightly from 2015, the highest-recorded production level EIA 2017b).

AEO 2018 projects that domestic natural gas production will continue to grow, increasing by 16.0 trillion cubic feet (Tcf) from 2016 to 2050, a 1.4 percent increase. This is driven by a 2.4 percent increase in shale gas production, representing an 18.5 Tcf increase in shale gas production.

Figure 3-2 shows the change in the price per MMBtu of fossil fuels for electricity generating units from 2006 to 2016. Over this time period the national annual average cost of natural gas per MMBtu decreased by 65 percent, illustrating that the increase in natural gas supply has exerted downward pressure on natural gas prices. Over this same period the cost of coal receipts increased by 6.2 percent.

Figure 3-2. Change in National Annual Average Cost of Real Fossil Fuel Receipts at EGUs per MMBtu.



Source: EIA Monthly Energy Review Dec. 2017, Table 9.9
 Note: Costs include taxes.

Current and expected trends in natural gas and coal markets are contributing to decisions in new power plan development. However, the more important decision-making metric for power plants is long-run expected prices. Because new power plants have asset lives measured in decades, new capacity investment decisions are based on long-run expected prices. These long-run fuel trends are discussed in the following section.

3.5.1 Power Sector Fuel Projections

Given that power plants are long-lived assets, capacity planning decisions are necessarily undertaken with a forward view of expected market and regulatory conditions. EIA capacity expansion projects are informed by a lifecycle cost analysis over a 30-year period in which the expectations of future prices are consistent with the projections realized in the model (i.e. the model executes decisions with perfect foresight of future market, technical, and regulatory conditions.) (EIA 2018b) Therefore, the fuel prices that inform capacity expansion decisions in a given year are not only the prices in that year, but the entire future fuel price stream. As shown in Table 3-3 above, AEO 2015 projects no new conventional coal-fired capacity across any of the alternative scenarios; Table 3-4 shows that in 2025 natural gas prices were greater, both on the whole and relative to their respective coal prices, in AEO 2015 than in AEO 2018.

It is useful to consider the price projections from AEO 2015 and AEO 2018 to examine their relationship. As shown in Table 3-5, on average 2025 natural gas prices fell by approximately two dollars per MMBtu across all of the scenarios in AEO 2015 and AEO 2018. Steam coal prices fell by an approximate average of forty cents across the scenarios. The fact that natural gas prices fell by five times the amount that coal prices fell further supports EPA's conclusion that projected market conditions in the AEO 2018 scenarios would be unlikely to project additional conventional coal generation if it was an available option in the model, given that coal is even less competitive as a generation technology than it was in AEO 2015, which did not project any new conventional coal.

Table 3-5. National Power Sector 2025 Delivered Fuel Prices by AEO Edition and Scenario (2016\$/MMBtu)

	AEO 2015	AEO 2018	Relative Difference
Natural Gas			
Reference Case	\$6.54	\$4.40	\$2.14
High Economic Growth	\$6.87	\$4.37	\$2.50
Low Economic Growth	\$6.18	\$4.25	\$1.93
High Oil Price	\$7.82	\$4.22	\$3.60
Low Oil Price	\$6.10	\$4.11	\$1.99
High Oil and Gas Resource	\$4.17	\$3.36	\$0.81
Steam Coal			
Reference Case	\$2.65	\$2.24	\$0.41
High Economic Growth	\$2.66	\$2.25	\$0.41
Low Economic Growth	\$2.62	\$2.22	\$0.40
High Oil Price	\$2.88	\$2.35	\$0.52
Low Oil Price	\$2.56	\$2.10	\$0.45
High Oil and Gas Resource	\$2.46	\$2.11	\$0.35

Note: The AEO 2015 and 2018 scenario definitions are summarized in Table 3-3 and Table 3-4 respectively. The low oil and gas resource scenario from AEO 2018 has been excluded from this table as it is not included in both editions of the AEO.

3.6 Electric Sector Trends

The emphasis on natural gas-fired capacity, as opposed to new coal capacity, is consistent with current trends, where natural gas-fired capacity has been the technology of choice for base load and intermediate load power generation. Table 3-6 illustrates this trend: from 2006 to 2016 net generation from coal decreased by 37.7%, while net generation from natural gas increased by 68.8%. This growth in natural gas-fired capacity has largely been the result of its significant levelized cost of electricity (LCOE)¹¹ advantage over coal-fired generating technologies. A greater discussion of the relative LCOE of different generating technologies is provided in Section 3.7 as well as Chapter 2.

¹¹ The levelized cost of electricity is an economic assessment of the cost of electricity from a new generating unit or plant, including all the costs over its lifetime: initial investment, operations and maintenance, cost of fuel, and cost of capital.

Table 3-6. Net Generation between 2006 and 2016 (Trillion kWh = TWh)

Energy Source	2006		2016		Change Between '06 and '16	
	Net Generation (TWh)	Fuel Source Share	Net Generation (TWh)	Fuel Source Share	Net Generation Change (TWh)	% Change in Net Generation
Coal	1,991	49%	1,239	30%	-751	-38%
Natural Gas	816	20%	1,378	34%	562	69%
Nuclear	787	19%	806	20%	18	2%
Hydro	283	7%	261	6%	-22	-8%
Petroleum	64	2%	24	1%	-40	-62%
Wind	27	1%	227	6%	200	754%
Solar	1	0%	36	1%	36	6997%
Other Renewable	69	2%	79	2%	9	13%
Misc.	27	1%	27	1%	-1	-2%
Total	4,065	100%	4,077	100%	12	0.3%

Source: EIA Electric Power Annual, Tables 3.1.A, 3.1.B

In addition to the fuel price advantages of natural gas discussed above, a number of states and regions have implemented regulations, policies, and programs related to emissions, renewable energy, and energy efficiency that are affecting the mix of fuels used to generate electricity and reducing the demand for electricity. For example, as of 2016, twelve states had passed legislation establishing greenhouse gas (GHG) emission reduction targets. Since January 2009, ten states have implemented emissions budget trading programs to address CO₂ and other GHG emissions, including California's Cap-and-Trade program and the nine northeast and mid-Atlantic states participating in the Regional Greenhouse Gas Initiative.¹² Between 1997 and 2012, four states – California, New York, Oregon, and Washington – enacted mandatory GHG emissions standards that impose enforceable emissions rate limits on new and/or expanded electric generating units.¹³ Between 2006 and 2009, three states—California, Oregon, and

¹² The nine northeast and mid-Atlantic states participating in the Regional Greenhouse Gas Initiative (RGGI), include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

¹³ California Energy Commission, California SB 1368, Chapter 598 available at: http://www.energy.ca.gov/emission_standards/. New York Department of Environmental Conservation, Part 251 CO₂ Performance Standards for Major Electric Generating Facilities. Available at: [https://govt.westlaw.com/nycrr/Browse/Home/NewYork/NewYorkCodesRulesandRegulations?guid=I5d3c9d90eafb11e19f38000845b8d3e&originationContext=documenttoc&transitionType=Default&contextData=\(sc.Default\)](https://govt.westlaw.com/nycrr/Browse/Home/NewYork/NewYorkCodesRulesandRegulations?guid=I5d3c9d90eafb11e19f38000845b8d3e&originationContext=documenttoc&transitionType=Default&contextData=(sc.Default)). Oregon Department of Energy, Oregon's Carbon Dioxide Emission Standards for New Energy Facilities. Available at: <http://www.oregon.gov/energy/Siting/docs/Reports/CO2Standard.pdf>. Washington State Legislature, Chapter 80.70 RCW: Carbon Dioxide Mitigation. Available at: <http://apps.leg.wa.gov/rcw/default.aspx?cite=80.70&full=true>. Illinois General Assembly, Public Act 095-1027,

Washington— enacted mandatory GHG emissions performance standards that set an emissions rate for electricity purchased by electric utilities.¹⁴

Many states have also adopted renewable portfolio standards (RPS), also known as renewable electricity standards (RES), as well as incentives or finance mechanisms for renewables. A RPS is a mandatory requirement for retail electricity suppliers to supply a minimum percentage or amount of their retail electricity load with electricity generated from eligible sources of renewable energy. As of February 2017, 29 states and Washington, D.C., have adopted a mandatory RPS, although designs vary (e.g., applicability, targets and timetables, geographic and resource eligibility, alternative compliance payments). An additional eight states have adopted voluntary renewable goals. (DSIRE 2017) Twenty-three states support the deployment of renewable energy technologies through performance-based incentives, which are paid based on the actual renewable energy production of a system. State and local governments offer more than 200 tax incentives to lower financial barriers to and encourage increases in renewable energy production. (DSIRE 2018)

States have also adopted programs to lower the demand for electricity. They include, but are not limited to, energy efficiency resource standards, building codes, and utility or third-party administrated demand-side energy efficiency programs. As of October 2016, 20 states have mandatory statewide energy efficiency resource standards in place, and eight states have goals, for a total of at least 28 states with some type of energy efficiency requirement or goal. (DSIRE 2016)

These state policies influence the generation profile of the electric sector. In general, these policies shift generation away from coal and towards natural gas and renewables, trends which we see reflected in the changes in net generation as well as projected future trends.

3.7 Levelized Cost of Electricity Analysis

New capacity projections from EIA and EPA’s IPM analysis reviewed in the previous section indicate that the proposed change in the NSPS is not projected to result in changes in the

SB1987, Clean Coal Portfolio Standard Law, January 12, 2009. Available at: <http://ilga.gov/legislation/publicacts/95/PDF/095-1027.pdf>. Montana State Legislature, H.B.0025.05, An Act Generally Revising the Electric Utility Industry and Customer Choice Laws, May 14, 2007. Available at: <http://leg.mt.gov/bills/2007/billpdf/HB0025.pdf>.

¹⁴ Ibid.

construction of new EGUs from what would be expected in the absence of this proposal. As a result, the proposed EGU New Source GHG Standards are projected to result in negligible emission changes, quantified benefits, or costs.

To further examine the conclusion that new coal facilities are unlikely to be constructed EPA conducted additional analysis using the levelized cost of electricity (LCOE) for different types of new generation technologies that would meet the proposed standards. The LCOE is a widely-used metric that represents the cost, in dollars per unit of output, of building and operating a generating facility over the entirety of its economic life. Evaluating competitiveness based on the LCOE is particularly useful in establishing cost comparisons between generation types with similar operating characteristics but with different cost and financial characteristics. (Joskow 2011) The typical cost components associated with the LCOE include capital, fixed operation and maintenance (FOM), variable operation and maintenance (VOM), and fuel.

3.7.1 Components of the Levelized Cost of Electricity

The levelized capital and FOM costs may be calculated by taking the annualized capital and FOM (expressed in \$/kW-yr) costs and spreading the expense over the annual generation of the facility using the expected average annual capacity factor (the percent of full load at which a unit would produce its actual generations if it operated for 8,760 hours). The annualized capital cost (expressed in \$/kW-yr) is the product of the \$/kW capital cost and the capital recovery factor (CRF). A CRF may be calculated using the project's interest rate and book life.¹⁵

The VOM cost, which is already expressed in terms of cost per unit of output, may be presented with or without the fuel expense. The fuel expense is typically the largest component of VOM costs; non-fuel components of VOM include start-up fuel, consumables, inspections, etc. For certain capacity types, such as NGCC, fuel expense may also represent the majority of the LCOE. In this analysis, the fuel cost is reported separately. However, the cost of

¹⁵ The interest rate assumed for NGCC projects is 9.06 percent; the interest rate assumed for coal-fired projects is 9.57 percent. All three types of projects are assumed to have a 30-year book life, resulting in a capital recovery factor of 9.78 percent for NGCC projects and 10.23 for coal-fired projects. Individual utilities may face different interest rates, resulting in different capital recovery factors.

transportation, storage, and monitoring (TS&M)¹⁶ of a CCS system is included in the VOM estimate for model units employing CCS.

Because levelized costs consider the entire lifecycle of the facility, fuel expenses are represented by the levelized fuel price that captures the forecast of annual delivered fuel prices over the economic life of the facility at a given discount rate.¹⁷ Levelizing fuel prices recognizes the need to consider the trajectory of fuel costs over the facility's entire economic life. For this analysis, a 30-year levelized fuel cost was calculated using a 4.5 percent discount rate applied to fuel prices from the AEO 2018 reference case and applying the average annual price increase from 2045 to 2050 in all subsequent years from 2051 through 2055. (EIA 2018c) Based on this approach the annualized steam coal price is \$2.32/MMBtu and the annualized natural gas prices is \$4.73/MMBtu. AEO 2018 reports utility steam coal prices but does not report bituminous coal prices, which are needed for this analysis. To estimate annualized prices by coal rank, EPA used 2017 form EIA-923 data for delivered fuel prices and delivered quantities to determine the annual average prices for each coal rank as well as the average steam coal price. (EIA 2018e) EPA then matched the steam coal price calculated from the form EIA-923 data to the AEO reference case steam coal price and applied the same growth rates as AEO 2018 reports for utility steam coal prices to individual coal ranks. For bituminous coal this results in a levelized bituminous coal price of \$2.61/MMBtu.

It should be noted that there are other important considerations beyond LCOE that impact power plant investment decisions. New power plant developers must consider the specific demand characteristics in any particular region, the existing mix of generators, operational flexibility of different types of generation, prevailing and expected electricity prices, other potential revenue opportunities (e.g., the capacity value of a particular unit, specific power market mechanisms to compensate units for availability to maintain reliability, sale of co-products, etc.), and the varying financial risks associated with different generation technologies.

¹⁶ Transmission and monitoring costs are discussed in section V.A.1.a.(3).(a) of the preamble.

¹⁷ As an illustration of applying a discount rate to a stream of future fuel prices, the levelized fuel price will be less than the mean fuel price if prices are increasing, equal to the mean if fuel prices are constant, and greater than the mean if fuel prices are declining. The weighting of nearer-term prices through the application of a discount rate is consistent with modeling economic behavior of investors. In this analysis, EPA used a 4.5 percent discount rate to calculate levelized fuel prices based on AEO 2018c.

Broader system-wide power sector modeling – such as the analyses done by EPA and EIA – is able to more effectively capture some of these considerations.

The technology cost and performance assumptions that form the basis for the LCOE analysis in this chapter as well as Chapter 2 are from the DOE’s National Energy Technology Laboratory (NETL). (NETL 2015) The use of the NETL cost and performance characteristics allows for comparisons to be made across generating technologies using a single, internally-consistent framework. For convenience, the technology cost and performance characteristics utilized in developing the LCOE estimates discussed in this chapter as well as Chapter 2 are listed below in Table 3-7.¹⁸

To represent new supercritical pulverized coal (SCPC) and subcritical pulverized coal facilities, NETL assumed a new bituminous coal-fired boiler with a combination of low-NO_x burners with overfire air and a selective catalytic reduction system for NO_x control. The plant is assumed to have a fabric filter and a wet limestone flue gas desulfurization scrubber for particulate matter and SO₂ control respectively. For configurations including CCS, the plant is assumed to have a sodium hydroxide polishing scrubber to ensure that the flue gas entering the CO₂ capture system has a SO₂ concentration of 10 parts per million or less. The PC unit treating a slip stream with partial post-combustion CCS is assumed to be equipped with the CO₂ removal system designed by Shell Cansolv, the system currently in full-scale commercial use at the Boundary Dam facility.¹⁹ Estimated costs for the system reflect the latest vendor quotations.

Specific to the partial capture configurations for SCPC, the NETL study identified two options. The first option identified was to process the entire flue gas stream through the capture system, but at reduced solvent circulation rates. The second option was to maintain the same high solvent circulation rate and stripping steam requirement as would be used for full capture, but only treat a portion of the total flue gas stream. The NETL report determined that this “slip stream” approach was the most economical because a reduction in flue gas flow rate would: (1)

¹⁸ The LCOE calculations used in this analysis all assume an 85 percent capacity factor and do not use the adjusted capacity factor approach discussed in the preamble accompanying this action. Additionally, NETL assumes a 550 MW capacity EGU in developing its cost estimates. To the extent that there are economies of scale, these are not accounted for in downscaling to the 150 MW_{net} capacity and the LCOE for these facilities may be higher than that estimated here.

¹⁹ NETL 2015 at 59, 137.

decrease the quantity of energy consumed by flue gas blowers; (2) reduce the size of the CO₂ absorption columns; and (3) trim the cooling water requirement of the direct contact cooling system.²⁰ The slip stream approach – which leads to lower capital and operating costs – was therefore adopted by EPA for cost and performance estimates under partial capture.

Table 3-7. Technology Cost and Performance Specifications (2016\$)

	Capital Cost (\$/MWh)	Fixed Operations & Maintenance (\$/MWh)	Variable Operations & Maintenance (\$/MWh)	Levelized Fuel Cost (\$/MWh)	Total LCOE (\$/MWh)	Net Plant HHV Efficiency (%)
<i>Assumed Capacity of 600 MW_{net}</i>						
NGCC	12	4	2	31	49	51.5
SCPC	40	10	9	22	82	40.7
SCPC w/ Partial CCS under 2015 final standard of 1,400 lb/MWh gross	50	12	14	23	99	39.2
<i>Assumed Capacity of 150 MW_{net}</i>						
NGCC	12	4	2	31	49	51.5
Subcritical PC	39	10	10	23	81	39.0
Subcritical PC w/ Partial CCS under 2015 final standard of 1,400 lb/MWh gross	50	12	15	24	100	37.4

Notes: HHV efficiency refers to higher heating value efficiency. Cost from NETL 2015. The coal assumed is a bituminous coal with a sulfur content of 2.8 percent (dry) at a real (2016\$) price of \$2.61/MMBtu, consistent with AEO 2018. The analysis uses a real (2016\$) natural gas price of \$4.73/MMBtu. All values are calculated assuming an 85 percent capacity factor. For facilities equipped with partial CCS, variable operations and maintenance costs include the cost to transport and sequester the captured CO₂.

NETL (2015) explains that there are a range of future potential costs that are up to 15 percent below, or 30 percent above their central estimate, consistent with a “feasibility study” level of design engineering applied to the various cases in this study. The value of the studies lies not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.

The illustrative unit cost and performance characteristics used in this section, as well as the LCOE analysis in Chapter 2, assume representative costs associated with spatially-dependent components, such as connecting to existing fuel delivery infrastructure and the transmission grid.

²⁰ NETL based this determination primarily upon a review of the literature. See page 2 of NETL 2013.

Additionally, some facilities may face other location-specific costs, such as the need to purchase water rights. In practice, units may experience higher or lower costs for these components depending on where they are located.

The LCOE comparisons presented in this section only represent the cost to the generator and do not reflect the additional social costs that are associated with emissions of greenhouse gases or other air pollutants. A broader consideration of health and welfare (i.e. non-health) impacts of emissions from these technologies is considered in Chapter 2.

3.7.2 Levelized Cost of Electricity of New Generation Technologies

To support and provide context for the modeling results presented above, this section presents two LCOE comparisons:

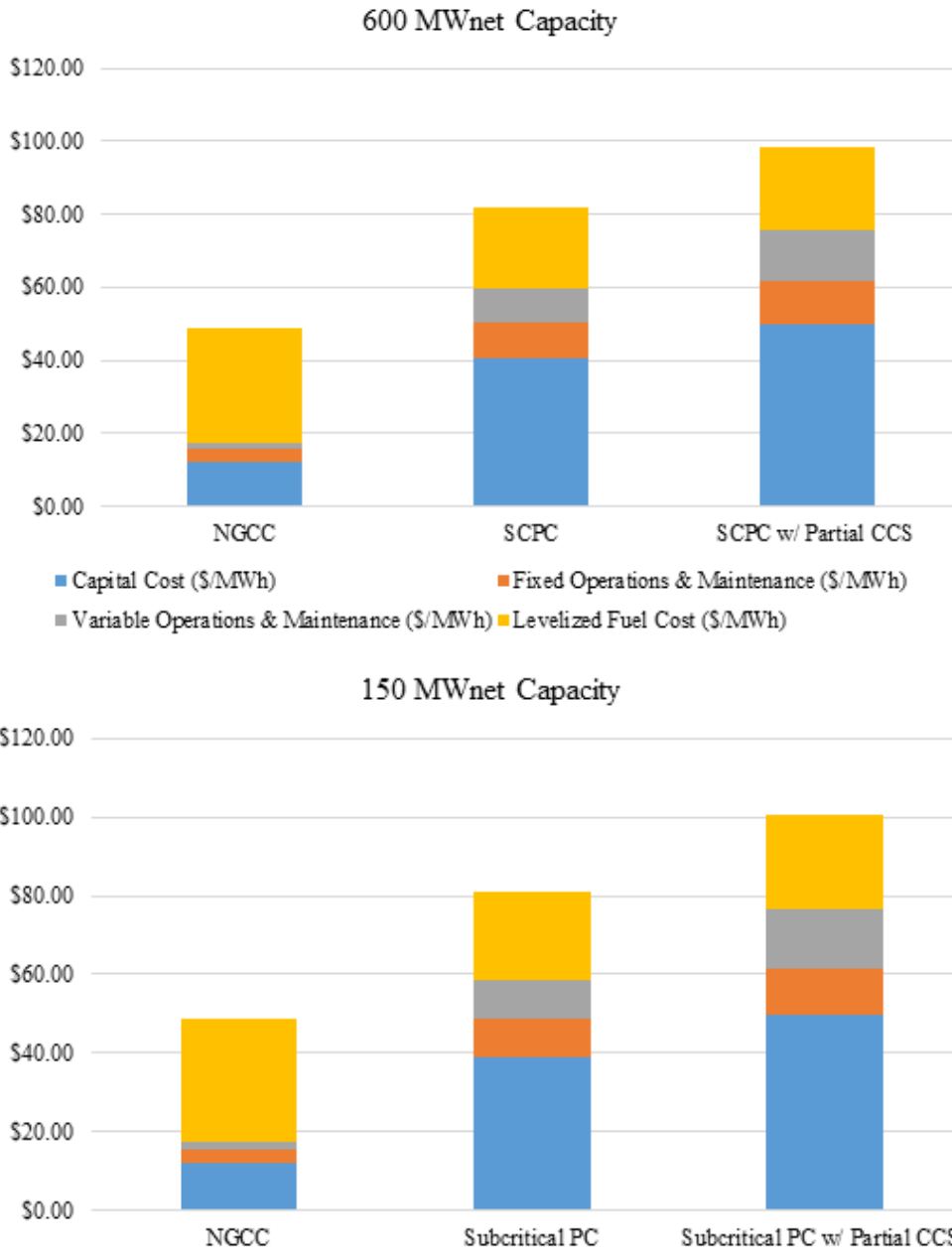
1. NGCC to SCPC for a 600 MW_{net} capacity facility. This capacity is assumed to generally correspond to the proposed standard for sources with a heat input > 2,000 MMBtu/h.
2. NGCC to a subcritical generation for a 150 MW_{net} capacity facility. Even though the NETL costs are for larger facilities, this capacity is assumed to approximately correspond to the proposed standard for sources with a heat input ≤ 2,000 MMBtu/h.

Two different facility capacities are presented as the proposed new source standards now differentiate by heat input. Detailed LCOE cost components for both SCPC and subcritical generation appear in Table 3-7 and appear below graphically in Figure 3-3.

Although EPA believes that this cost data is broadly representative of the economics between new coal and new natural gas facilities, this analysis assumes representative new units and does not reflect the full array of new generating sources that could potentially be built. To the extent that other types of new EGUs that would be affected by this rule are built, they may exhibit different costs than those presented here. For example, some technologies could potentially display a lower LCOE if, all else equal, fuel could be obtained at a lower price than that assumed in this analysis, as may be the case for coal refuse facilities. However, these potential differences do not fundamentally change the results of this analysis. The proposal includes a standard specific to coal refuse facilities and while this technology could exhibit

different local economics, particularly in the delivered price of fuel, from a capital and operating perspective EPA believes the cost and performance of these units are broadly similar to other coal-fired EGUs and therefore are well represented by new, conventional coal-fired generation.

Figure 3-3. Illustrative Wholesale Levelized Cost of Electricity by Cost Component (2016\$/MWh) for both 600 and 150 MW_{net} Capacity



Notes: Cost from NETL 2015. The coal assumed is a bituminous coal with a sulfur content of 2.8 percent (dry) at a real (2016\$) price of \$2.61/MMBtu, consistent with AEO 2018. The analysis uses a real (2016\$) natural gas price of \$4.73/MMBtu. All values are calculated assuming an 85 percent capacity factor. For facilities equipped with partial CCS, variable operations and maintenance costs include the cost to transport and sequester the captured CO₂.

NETL (2015) explains that there are a range of future potential costs that are up to 15 percent below, or 30 percent above their central estimate, consistent with a “feasibility study” level of design engineering applied to the various cases in this study. The value of the studies lies not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.

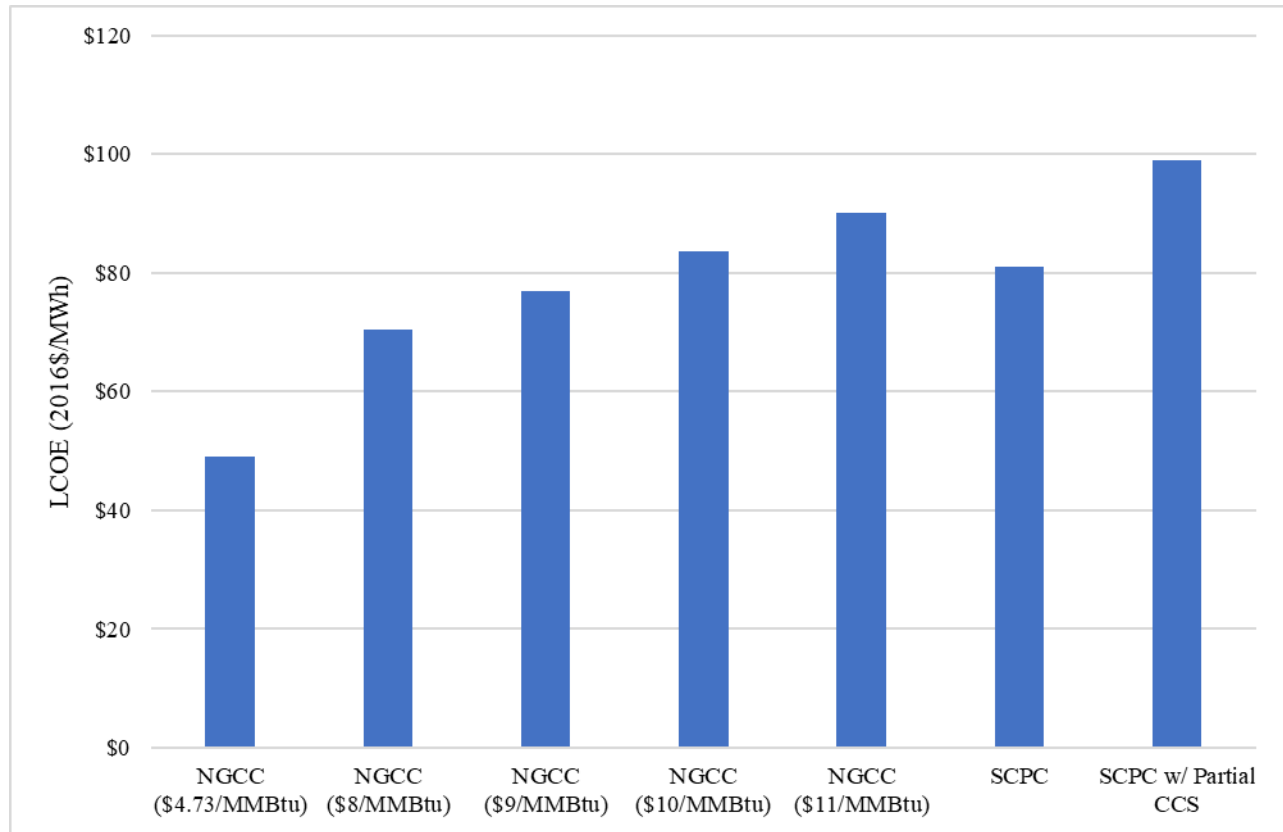
The LCOE of NGCC is significantly lower than all coal-fired options for both subcritical and SCPC generation. For technologies that are included in IPM and the AEO, their LCOE values are comparable to the LCOE values calculated from the NETL study. The difference in the LCOE of NGCC and coal technologies explains the finding in the sectoral modeling described above that natural gas generation is expected to provide new fossil-fired generation rather than coal.

These calculations do not include any adder to the cost of capital to reflect financial risks associated with power plants with a relatively higher rate of carbon dioxide emissions, which is applied by EIA to reflect the costs used in resource planning exercises commonly conducted by the industry. (EIA 2018b) The inclusion of this adder would not impact the finding in Figure 3-3 that the LCOE of new NGCC is significantly lower than all coal-fired options for both subcritical and SCPC generation, since it would increase the LCOE for coal-fired technologies and make the differences even greater.

In addition to the disparity in total LCOE, there are fundamental differences in the cost composition between natural gas- and coal-fired facilities. NGCC costs are dominated by fuel expense while the levelized cost of coal-fired technologies is driven by capital expense. Consequently, this section will explore the impact of changes in natural gas price and the capital costs of coal-fired facilities to better quantify the magnitude of the relative cost advantage NGCC exhibits over coal-fired alternatives. Given the similarities in cost between subcritical and SCPC generation the discussion that follows focuses on the LCOE of SCPC, but the results are applicable to subcritical generation as well.

Figure 3-4 presents the LCOE of a 600 MW_{net} NGCC facility at five alternative natural gas price levels. For comparison, the LCOE estimate for SCPC is provided as well.

Figure 3-4. Illustrative Wholesale Levelized Cost of Electricity Across Alternative Natural Gas Prices (2016\$/MMBtu)



It is only when natural gas prices reach \$10/MMBtu on a levelized basis (in 2016 dollars) that new coal-fired generation approaches parity with NGCC in terms of the LCOE. None of the AEO 2018 scenarios described in this chapter project natural gas prices near that level.²¹ To achieve a \$10/MMBtu levelized price in 2025 would require a significantly more pessimistic natural gas outlook than what is contained in AEO 2018’s low natural gas resource scenario, which projects the highest prices for natural gas across all of the AEO 2018 scenarios. To illustrate, Table 3-8 reports the levelized natural gas prices from an initial year of 2025 for both a

²¹ As noted earlier in this chapter, investment decisions require consideration of fuel price projections over long periods of time; similarly, the power sector modeling cited here make fuel price projections over long periods of time. Neither these modeling projections nor these LCOE calculations are meant to suggest that the gas price could not reach as high as \$10/MMBtu at any given point in time, but these analyses do not expect such a price level to be sustained over a period of time that would influence an economic assessment of which type of new capacity offers a better investment.

20-year and 30-year period. Calculating the price projections for a 30-year period requires continuing the projected prices to 2054 from 2050, the last year of projected prices in AEO 2018, which is done by applying the average annual price increase from 2045 to 2050 in all subsequent years from 2051 through 2055.

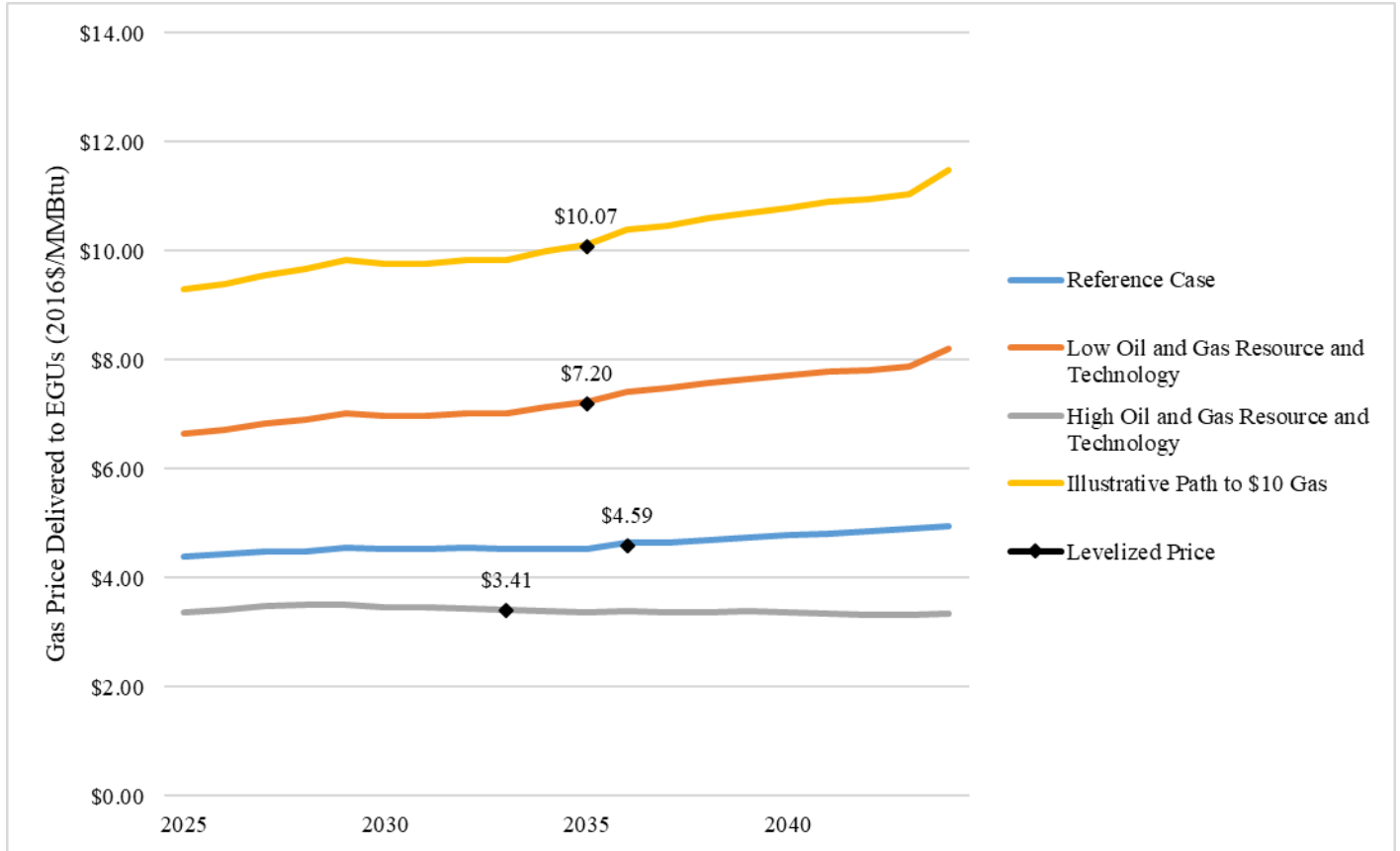
Table 3-8. Levelized Natural Gas Prices by AEO 2018 Scenario (2016\$/MMBtu)

Scenario	20-Year AEO Projection	30-Year AEO- Based Projection
	(2025-2044)	(2025-2054)
Reference	\$4.59	\$4.73
High Growth	\$4.73	\$4.95
Low Growth	\$4.47	\$4.57
High Oil Price	\$4.90	\$5.11
Low Oil Price	\$4.37	\$4.52
High Gas/Oil Resource	\$3.41	\$3.41
Low Gas/Oil Resource	\$7.20	\$7.62

Note: These calculations utilize a discount rate of 4.5 percent (EIA 2018c). The 30-year natural gas price is calculated by applying the average annual price increase from 2045 to 2050 in all subsequent years from 2051 through 2055. The scenarios in AEO 2018 are described in Table 3-4.

To achieve a \$10/MMBtu natural gas price on a 20-year levelized cost basis in 2025 natural gas prices would need to be 40 percent higher than the scenario with the highest natural gas price in AEO 2018, the low oil and gas resource case, and 120 percent higher than AEO 2018’s reference case. As an illustration, Figure 3-5 shows a potential price path that would reach a \$10/MMBtu natural gas price on a 20-year levelized cost basis in 2025 is a natural gas price path where prices are 40 percent higher than AEO 2018’s low resource scenario in all years. This illustrative price path to achieve a \$10/MMBtu levelized price would result in a \$10.12/MMBtu real price in 2035 and a real price of \$11.48 in 2044 (all prices are in 2016 dollars.) This analysis shows that natural gas price projections need to be notably higher than the highest price projection in the AEO 2018 scenarios before market dynamics would be expected to favor new coal generation over natural gas generation.

Figure 3-5. Projected Real National Delivered Natural Gas Price for Select AEO 2018 Scenarios and Illustrative Path for >\$10/MMBtu Levelized Price



It is important to note that LCOE calculations are based on assumptions regarding the representative national cost of generation at new facilities. It is known that there is spatial variation in the costs of new generation due to design differences, labor productivity and wage differences, fuel prices, and other factors. To account for these differences EIA uses capital cost scalars to capture regional differences in labor and construction costs. (EIA 2016) The minimum and maximum capital costs scalars across all regions in AEO 2018 for pulverized coal and NGCC build options are presented in Table 3-9.²²

²² The capital cost scalars exclude New York City and Long Island areas, as NEMS does not generate pulverized coal capital cost scalars for these areas as new coal cannot be constructed due to state and local regulations.

Table 3-9. AEO 2018 Regional Capital Cost Scalars by Capacity Type

Capacity Type	Minimum Capital Cost Scalar	Maximum Capital Cost Scalar
Pulverized Coal	0.89	1.15
NGCC	0.89	1.24

Applying the regional capital cost scalars displayed above to the capital cost component of the base LCOE estimates from NETL developed earlier in this section produces only a small change in the relative competitiveness of the technologies as seen in Table 3-10. The LCOE of SCPC generation in the lowest capital cost region still results in a LCOE that is above NGCC in the most expensive region.

Table 3-10. LCOE Estimates with Minimum and Maximum AEO 2018 Regional Capital Cost Scalars (2016\$/MWh)

Capacity Type	Reference LCOE (\$/MWh)	LCOE Using Minimum Capital Cost Scalar (\$/MWh)	LCOE Using Maximum Capital Cost Scalar (\$/MWh)
SCPC	82	73	95
NGCC	49	48	51

This analysis shows that with current trends in natural gas prices expected to continue, even with regional variability in capital costs new coal-fired generation is not the most cost-effective form of generation. Given the analysis above shows that natural gas prices would need to generally be 40 percent higher than the AEO 2018's highest projected gas prices for NGCC generation to be comparable to coal on a LCOE basis, it is unlikely new coal-fired generation will be constructed within the analysis period.

3.8 References

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CHAPTER 4: MODIFIED AND RECONSTRUCTED SOURCE IMPACTS

4.1 Introduction

In addition to the standard for new sources analyzed in Chapter 2 and Chapter 3, this action also proposes changes to the standards under Clean Air Act Section 111(b) for units that modify or reconstruct. Specifically, for modified and reconstructed fossil fuel-fired generating units this action proposes to:

- Increase the maximum stringency of the standard for modified fossil fuel-fired sources with heat input > 2,000 MMBtu/h from 1,800 lb CO₂/MWh-gross to 1,900 lb CO₂/MWh-gross.
- Introduce a standard specific for coal refuse-fired sources of 2,200 lb CO₂/MWh-gross.

For the reasons discussed in this chapter, EPA believes that the proposed standards for modified and reconstructed fossil fuel-fired EGUs will result in minimal compliance costs, because we expect few 111(b) modified or reconstructed EGUs in the period of analysis (through 2026.)

4.2 Reconstructed Sources

The new source performance standard (NSPS) provisions (40 CFR part 60, subpart A) define a “reconstruction” as the replacement of components of an existing facility to an extent that (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible to meet the applicable standards. Historically, EPA is aware of only one EGU that has notified EPA that it has reconstructed under the reconstruction provision of section 111(b). As a result, we anticipate that very few EGUs may undertake reconstruction in the period of analysis. For this reason, the proposed standards are not anticipated to result in any significant emission reductions, costs, or benefits in the period of analysis.

4.3 Modified Sources

Historically, few EGUs have notified EPA that they have modified under the modification provision of section 111(b). EPA's current regulations define a NSPS "modification" as a physical or operational change that increases the source's maximum achievable hourly rate of emissions, but projects that install pollution control equipment or systems are specifically exempt from that definition.

EPA expects that most of the actions EGUs are likely to take in the foreseeable future that could be classified as NSPS "modifications" would qualify for exemptions as pollution control projects. In some cases, those projects could involve the installation of add-on control equipment to meet Clean Air Act (CAA) requirements for criteria and air toxics air pollutants. In other cases, projects exempted from the definition of modification could involve equipment changes to improve fuel efficiency to meet state requirements for implementation of the CAA section 111(d) standards for existing sources and could have the effect of increasing a source's maximum achievable hourly emission rate (lb CO₂/hr), even while decreasing its actual output-based emission rate (lb CO₂/MWh).

Even if actions taken by EGUs to meet CAA 111(d) requirements were not considered pollution control projects, these actions would be unlikely to increase the maximum achievable hourly emissions by greater than 10 percent and thus the facility would not be subject to the section 111(b) modification provisions. EPA does not have sufficient information at this time to predict the full array of actions that existing steam generating units may undertake, including those in response to applicable requirements under an approved CAA section 111(d) plan; however, we note that the BSER under the proposed 111(d) State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units is composed of heat rate improvements, which generally should lower CO₂ hourly emissions.

Based on this information, we anticipate that few if any EGUs will take actions that would be considered NSPS modifications and subject to the standards of performance proposed in this action during the period of analysis. For this reason, the standards are anticipated to result in minimal emission changes, costs, or benefits in the period of analysis. Similarly, the Agency does not anticipate impacts on the price of electricity or energy supplies. This rule is not expected to raise any resource adequacy concerns, since reserve margins will not be impacted

and the rule does not impose any additional requirements on existing facilities not triggering the NSPS modification provision.

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