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America's
Natural Gas
Alliance

December 1, 2014

Docket ID No. EPA-HQ-OAR-2013-0602
Air and Radiation Docket and Information Center, Mailcode: 28221T
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue NW, Washington, DC 20460
(Submitted via regulations.gov)

Re: Comments of America's Natural Gas Alliance – Proposed Rule – Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (Docket ID No. EPA-HQ-OAR-2013-0602)

Dear Docket Clerk:

America's Natural Gas Alliance ("ANGA") appreciates the opportunity to submit these comments on the U.S. Environmental Protection Agency's ("EPA" or "the Agency") Proposed Rule – *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* ("Proposed Rule" or "section 111(d) rule for EGUs"), published at 79 Fed. Reg. 34830-958 (June 18, 2014).

Representing North America's leading independent natural gas exploration and production companies, America's Natural Gas Alliance works with industry, government and customer stakeholders to promote increased demand for and continued availability of our nation's abundant natural gas resource for a cleaner and more secure energy future. The combined natural gas production of the ANGA member companies is approximately eight trillion cubic feet per year, an amount that represents about one third of the total annual U.S. natural gas supply.

Natural gas is a clean-burning, efficient and cost-effective fuel. The safe and environmentally responsible development of our domestic stores of natural gas has been, and increasingly will be, an important component of America's energy supply and economic vitality. In the electricity sector, natural gas-fired generation is used for both baseload and peaking power, offering electric utilities the ability to significantly reduce air pollution while maintaining reliable power supplies. Natural gas-fired combustion turbines are uniquely capable of rapid starts and ramping to respond promptly to unplanned outages and rapidly changing power demands during the day. As a result, natural gas generation plays a key role in providing baseload power and supporting intermittent power sources, including renewable energy.

As a matter of policy, ANGA supports environmental regulation based on sound science and best available data. The comments offered below should not be interpreted as support for EPA's authority to regulate greenhouse gases under the Clean Air Act ("CAA") or for the regulatory structures proposed by EPA. Rather, these comments are offered in the context of EPA's proposal given EPA's interpretation of its authority and regulatory structures proposed. EPA must assure that this rule is sufficiently supported by technical information in the docket and fully considers how CAA section 111 addresses requirements for existing units. The comments offered herein are therefore centered on five primary areas:

(1) Natural gas generation is a critical part of addressing the environmental goals of this rulemaking, as well as meeting the nation's need for reliable and affordable energy. Natural gas generation is capable of supplying an increasing amount of overall baseload electric demand, and is uniquely able to support the use of intermittent power sources, including renewable energy.

(2) Section 111(d) does not permit EPA to consider potential construction of or emissions from new natural gas combined cycle ("NGCC") facilities or other new fossil fuel-fired units in determining the best system of emission reduction ("BSER") for existing sources.

(3) ANGA supports EPA's adoption of rate-based standards in the proposed rule, which is consistent with its section 111 authority. The proposed rate-based emission standards provide regulatory flexibility, allowing states and sources to respond to growing economies and changing market demands. As

discussed later in the comments, because the U.S. manufacturing sector is relatively more efficient and the U.S. power sector is relatively less carbon intensive, a rate-based standard that enables the continued onshoring of manufacturing will actually lead to net global reductions in CO_2 and other emissions.

(4) ANGA does not support EPA's inclusion of non-fossil fuel-fired generation within its determination of BSER or its reliance on non-emitting activities in establishing BSER. EPA has exceeded its statutory authority in attempting to include sources outside of the regulated source categories and in attempting to include non-emitting sources and activities in setting "guidelines" for state plans to be submitted under CAA section 111(d).

(5) To the extent that energy efficiency measures are relied upon in state compliance plans, EPA should provide clear guidance to ensure that such state plans include stringent evaluation, measurement, and verification ("EM&V") programs to ensure that claimed emissions reductions are proven. Approvable EM&V measures should be comparable between states.

I. Benefits of Natural Gas to Environment and Grid Reliability

A. Natural Gas-Fired Generation Is Critical to Meeting Environmental Goals and Energy Demands.

As EPA recognizes through this proposed rulemaking, using natural gas for electric generation provides a range of benefits. Natural gas is a low-cost technology that can, and does, provide reliable baseload, peaking or intermediate power. Given its ability to ramp up quickly, natural gas-fired power plants play an important role in maintaining electric system reliability and accommodating intermittent electricity sources, such as wind and solar generation. Natural gas also assists in reducing air pollution emissions associated with electricity generation. Current U.S. Energy Information Administration ("EIA") data indicate that annual carbon dioxide ("CO_2") emissions from the electric power sector in 2013 were 364 million metric tons less than annual emissions in 2005.[1] Altogether, the EIA estimates that "over a billion metric

[1] U.S. Energy Information Administration, *Monthly Energy Review September 2014*, Table 12.6, *available at* http://www.eia.gov/totalenergy/data/monthly/pdf/sec12_9.pdf.

tons of CO_2 emission have been averted . . . since 2005" and attributes much of these savings to increased natural gas use.[2]

Natural gas power plants are highly efficient and emit no mercury air pollution, virtually no sulfur dioxide or particulate matter, and significantly lower nitrogen oxides and greenhouse gases when compared to other types of fossil fuel power plants.[3] In addition, natural gas power plants have a small physical footprint when compared to other similarly sized power plants, including renewables, making natural gas a clear choice for urban, suburban, and other space-constrained areas. Because of the low emissions and small footprint of natural gas power plants, they can also be sited closer to urban areas and other demand centers for power, relieving electric grid transmission constraints and the need for long distance high-voltage power lines.

The capacity of natural gas to meet growing energy demands is particularly significant in light of the resurgence in U.S. manufacturing. As discussed in the EIA's Annual Energy Outlook ("AEO") 2014, industrial energy use is expected to grow through 2040, with total delivered energy consumption to the industrial sector increasing by 28 percent from 2012 to 2040.[4] Natural gas supplies and systems are expected to play an important role in satisfying the high power demand of the burgeoning manufacturing sector, and can do so at significantly reduced emission rates.[5] Further, natural gas facilities are scalable and require only minimal lead time as compared with other traditional power sources – a key advantage in serving a variety of growing industries. Moreover, in light of the continued positive outlook for natural gas supply and availability, the electricity sector's use of natural gas as fuel will not hinder manufacturing and commercial growth and, more specifically, will not impede the availability of natural gas as a feedstock for other industrial uses.[6]

In addition, natural gas has helped to balance the fuel and energy sources used to generate electricity. As depicted in Figure 1, the grid has diversified and is projected to continue to

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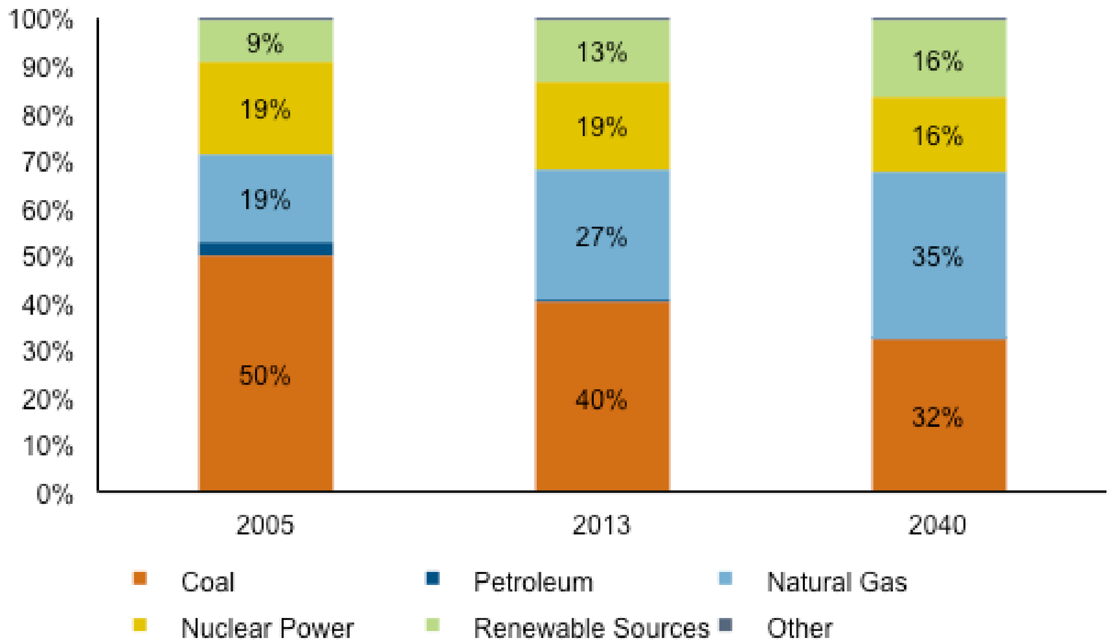
[2] U.S. Energy Information Administration, *U.S. Energy-Related Carbon Dioxide Emissions, 2013*, at 9 (October 2014), *available at* http://www.eia.gov/environment/emissions/carbon/pdf/2013_co2analysis.pdf.
[3] National Energy Technology Laboratory, Life Cycle Analysis: Power Studies Compilation Report, January 2011; Prudent Development, National Petroleum Council, Chapter 4, 2011.
[4] U.S. Energy Information Administration, *Annual Energy Outlook 2014*, at MT-11, *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf.
[5] *See id*.
[6] *See infra*, Section II.

become more diverse both through public policy programs supporting growth of renewable generation and through expanded natural gas generation resulting from stable, affordable natural gas prices in the wake of the shale gas revolution. According to EPA, the share of total domestic electricity generation attributable to natural gas grew by 40 percent between 2005 and 2013 (from 19 percent to 27 percent), and that share is expected to further grow by 80 percent relative to 2005 by 2040, when EIA projects 35 percent of the country's electric power fleet to be fueled by natural gas. The flexibility that natural gas generation provides makes natural gas the fuel of choice under all energy and environmental policies that aim to ensure emission reductions while minimizing adverse economic effects.

Figure 1: Electricity Generation by Fuel: 2005, 2013, 2040 (EIA AEO 2008 and 2014)



As reflected in the EIA data shown in Figure 1, since 2005, natural gas-fired power plants have provided an increasing percentage of delivered electricity. This trend is expected to continue in the coming decades. A key advantage of natural gas-fired power plants, whether in simple cycle or combined cycle configurations, is the flexibility to operate around the clock or to ramp generation quickly and efficiently.

As EPA has acknowledged in this proposal and in the CAA section 111(b) proposal for new sources, NGCCs can effectively and efficiently supply baseload power to the electric power system. In 2013, natural gas-fired power plants accounted for over 50 percent of new utility-scale generating capacity.[7] About half of that capacity came in the form of NGCC power plants that provide intermediate and baseload power. Over the first six months of 2014, natural gas-fired power plants again made up more than half of the utility-scale capacity additions in the United States.[8] Almost all of these plants were NGCC. The majority of these new combined cycle power plants are designed to serve baseload power in the regions in which they operate. In addition to recognizing the role of new NGCCs as a baseload resource, there is a recognition in the industry that current price and regulatory dynamics have created an opportunity for existing NGCCs to increase utilization and act as a baseload resource. Existing NGCC resources also have the ability to operate at high utilization levels, at or above 70 percent, without sacrificing the ability to fill other needs. Specifically, NGCC units running at high capacity factors may still operate as load following units and retain the ability to quickly ramp up or down in response to fluctuations in renewable energy supply and electricity demand throughout the day. From 2008 to 2012, as average capacity factors for the domestic coal fleet dropped from 73 to 57 percent, average NGCC capacity factors increased from 40 to 51 percent.[9]

Additionally, the operating characteristics of natural gas-fired power plants enable the expansion of intermittent resources, like solar and wind, allowing grid operators to keep supply and demand of electricity in balance. According to EIA, 37 states have renewable portfolio standards ("RPS") or renewable targets.[10] These requirements and goals can present many challenges. Whereas conventional thermal resources such as coal-fired power plants and natural gas turbines turn output up and down by increasing or decreasing fuel consumption in response to electricity demands, variable renewable energy sources such as wind and solar increase and decrease output based on wind and daylight conditions. These factors may or may not be correlated with demand and are outside the control of system operators. In order to keep supply and demand of electricity evenly balanced, grid operators must address the variability of output

[7] Energy Information Agency. *Half of power plant capacity additions in 2013 came from natural gas*. (April 2014), available at http://www.eia.gov/todayinenergy/detail.cfm?id=15751.
[8] Energy Information Agency. *Natural gas, solar, and wind lead power plant capacity additions in first-half 2014*. (September 2014), available at http://www.eia.gov/todayinenergy/detail.cfm?id=17891.
[9] Energy Information Agency. *Table 6.7.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels, January 2008-August 2014.* (October 2014), Available at: http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_a.
[10] Energy Information Agency. *Most states have Renewable Portfolio Standards*. (February 2012), available at http://www.eia.gov/todayinenergy/detail.cfm?id=4850.

from these energy sources, and the uncertainty associated with the timing and magnitude of that variability.

The most direct form of support for renewable power is flexible generation that plant operators can quickly turn on at the request of grid operators. In this regard, natural gas combustion turbines have the ability to ramp up and provide power very quickly while other sources may take hours to reach full capacity. The presence of natural gas generation therefore provides grid operators the freedom to accept capacity from renewable energy sources without putting electric system reliability at risk.

A range of studies have affirmed the important role of natural gas-fired power plants in enabling renewable power:

- A 2010 report completed for the California Independent System Operator ("ISO") by ISO staff and GE Energy Consulting found that "Gas plants are particularly important because they currently provide most of the ramping and ancillary service capability for the ISO."[11]
- A 2011 report completed for the Interstate Natural Gas Association of America ("INGAA") by ICF International estimated that for firming of intermittent resources, a reserve capacity of 259 MW is required for every gigawatt of wind or solar integrated into the grid.[12]
- A 2011 report by researchers at the Massachusetts Institute of Technology ("MIT"), *The Future of Natural Gas*, found that "[n]atural gas-fired power generation provides the major source of backup to intermittent renewable supplies in most U.S. markets" and that such capacity will be needed to provide system reliability in the future.[13]
- A 2012 report by researchers at the National Renewable Energy Laboratory in collaboration with the Joint Institute for Strategic Energy Analysis reviewed the

[11] California ISO. *Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS* (August 31, 2010), available at: https://www.caiso.com/Documents/Integration-RenewableResources-OperationalRequirementsandGenerationFleetCapabilityAt20PercRPS.pdf
[12] ICF International. *Firming Renewable Electric Power Generators: Opportunities and Challenges for Natural Gas Pipelines* (March, 2011), available at http://www.ingaa.org/File.aspx?id=12761.
[13] MIT . *The Future of Natural Gas* (2011), available at https://mitei.mit.edu/system/files/NaturalGas_Report.pdf.

opportunities for synergy between natural gas and renewable energy and found that "[i]n this critical period of industry adaptation to new energy paradigms, active engagement and partnership between the natural gas and renewable energy sectors can lead to efficient well-designed electricity markets better situated to achieving the long-term energy goals of energy security and climate change mitigation."[14]

- A 2013 Brattle Group report for the Texas Clean Energy Coalition found that "gas-fired generation also matches much better with intermittent renewable generation from solar and wind projects than do coal-fired power plants. The path to low-carbon generation in Texas will therefore likely require the co-development and integration of both gas and renewable resources."[15]

In 2013, North American Electric Reliability Corporation ("NERC") and California Independent System Operator ("CAISO"), operator of the grid in California, which has the nation's most aggressive RPS, sought to determine what changes to electricity system planning and operations would be necessary to ensure continued reliability of the grid while integrating large quantities of renewables (primarily wind and photovoltaic solar) into the North American bulk power system. NERC and CAISO found that the "increased supply variability associated with a significant penetration of variable resources will cause more frequent dispatches and the starting and stopping of flexible, gas-fired generators."[16] They concluded that natural gas-fired "plants provide California's electric system with needed ancillary services, including the ability for generators to ramp in response to significant changes in load, as well as voltage support and inertia necessary for import transfer capability and grid reliability."[17]

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[14] April Lee, Owen Zinaman, and Jeffrey Logan (National Renewable Energy Laboratory). *Opportunities for Synergy Between Natural Gas and Renewable Energy in the Electric Power and Transportation Sectors* (December 2012), available at http://www.nrel.gov/docs/fy13osti/56324.pdf.

[15] Dr. Jurgen Weiss, Heidi Bishop, Dr. Peter Fox-Penner, and Dr. Ira Shavel (The Brattle Group). *Partnering Natural Gas and Renewables in ERCOT* (June 11, 2013), available at http://www.texascleanenergy.org/Brattle%20report%20on%20renewable-gas%20FINAL%2011%20June%202013.pdf.

[16] North American Electric Reliability Corporation and the California Independent System Operator. *2013 Special Reliability Assessment: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach* (November 2013), available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf.

[17] *Ibid.*

The advantages of clean-burning natural gas-fired generation consistently outweigh other alternatives, even during extreme weather events. In particular, the "Polar Vortex" that occurred during the winter of 2013/2014 created multiple challenges for grid operators. For example, the "forced outage rate" in the PJM market during this time was two to three times higher than PJM's typical winter forced outage rate, resulting in tight system conditions (although power supplies were never interrupted).[18] The majority of problems encountered during these extreme conditions, however, were not an issue of natural gas availability. PJM, in a letter in response to questions about the polar vortex from members of the U.S. House Committee on Energy and Commerce, wrote:

- Although there has been much focus on gas issues associated with interruptible transportation, overall the gas interruptions were not the major driver of the high forced outage rates experienced in the PJM region. Natural gas interruptions, although significant, removed less than five percent of the total capacity required to meet demand on January 7, while equipment issues associated with both coal and natural gas units made up the far greater proportion of forced outages.[19]
- More than three quarters, or 30,900 MW, of the forced outages were associated with equipment breakdowns, startup failures, and other problems related to operating generating facilities in extremely cold temperatures. These problems impacted all generation types, including 14,000 MW of coal capacity, 9,700 MW of natural gas capacity, 1,400 MW of nuclear capacity, and 6,100 MW of other capacity (including hydropower and oil). An increased focus on cold weather preparedness should help to mitigate these problems in the future.

Importantly, these "interruptions" were a function of the gas delivery contracts generators had with the pipelines. In times of high demand, generators holding a lower-cost, interruptible contract will see that service interrupted – that is wholly consistent with the contractual agreement and not a function of natural gas availability. This aspect is acknowledged in a separate communication where PJM noted that, "the gas supply problems experienced last winter

[18] On January 7, 2014 at 7 p.m., an unprecedented 22 percent of power plants (40,200 MW) in PJM were forced out of service by problems such as equipment breakdowns, prolonged operations in extremely cold temperatures, and fuel supply limitations. Glazer, Craig A. (PJM). PJM Response to Committee Questions re: Polar Vortex Impact on PJM. (April 18, 2014), available at: http://www.pjm.com/sitecore%20modules/web/~/media/documents/other-fed-state/20140418-pjm-response-to-committee-questions-polar-vortex-impact-on-pjm.ashx.
[19] *Ibid*. at p. 7.

were primarily contractual and economic, not physical constraints, meaning that for many gas-fired generators, fuel firmness can be achieved through new arrangements with marketers even without expansion of the gas pipeline system" which further demonstrates that natural gas availability was not the source of problems encountered during the polar vortex.[20]

B. NGCC Units Have the Technical Ability To Run At Or Above EPA's Proposed 70 Percent Natural Gas Utilization Goal.

In the proposed rule, EPA constructs its BSER analysis on the basis of the assumption that NGCC could achieve an average 70 percent target utilization rate. Yet EPA already recognizes that at least 10 percent of existing NGCC facilities perform at rates of at least 70 percent, and that the average annual availability for NGCC generally exceeds 85 percent.[21] It is clear that a target utilization rate at or above 70 percent is adequately supported by available data.

While recognizing expanded resource availability as a general matter, EPA's proposed rule underestimates expanding unit-level utilization capabilities throughout the NGCC fleet.[22] [23] High utilization (greater than 70 percent) of NGCC power plants is technically feasible and has been demonstrated in operation. The basic components of a combined cycle power plant are a gas turbine ("GTG"), a heat recovery steam generator ("HRSG"), and a steam turbine generator ("STG"). Gas turbine manufacturers can supply gas turbines with a mechanical availability of greater than 90 percent.[24] The gas turbine's performance establishes a baseline for the overall reliability and availability of the NGCC suite of equipment, as the HRSG and STG components have greater reliability than the gas turbine, and planned maintenance is simultaneous for the GTG. The HRSG is a piece of fixed equipment that requires inspections every 5 to 10 years and the steam turbine generator's availability is greater than 99 percent.[25]

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[20] Letter from consumer representatives to PJM Board of Managers. http://www.pjm.com/~/media/committees-groups/committees/elc/coalition-briefing-papers/ex-parte-joint-consumer-advocates.ashx

[21] 79 Fed. Reg. at 34857, 34863.

[22] *See, e.g.*, *id*. at 34864 (discussing the potential for substantial pipeline expansion and significant increases in natural gas supply resources).

[23] *See infra*, Section II.

[24] Siemens reliability data.

[25] STG availability data.

As EPA notes, many facilities using this technology already perform at or above a 70 percent capacity factor. Based on our review of EPA's Continuous Emissions Monitoring (CEMS) hourly operating data, 40 percent of currently operating NGCCs in the U.S. (211 units) have achieved at least one year since 2000 where their annual capacity factor was greater than 70 percent. Additionally, we found that 83 percent (444 units) of currently operating NGCCs in the U.S. have achieved at least one month since 2000 where their monthly capacity factor was greater than 70 percent. This data supports EPA's conclusion that NGCC units are able to achieve or exceed a 70 percent capacity factor.

To demonstrate the technical ability of NGCC units to operate above 70 percent utilization levels, we would encourage EPA to review the experience of cogeneration units. Cogeneration units are similar to NGCC units and likewise include a GTG and HRSG. However, cogeneration units differ in that they do not include an STG for additional power generation. Instead, steam produced is routed to an industrial process. Because of the steam linkage between the power generation and the steam generation for the industrial process, cogeneration units typically run as baseload generators to support the steam needs of the facility, often at a utilization rate of above 85 percent, as demonstrated by EPA CEMS hourly operating data. Because cogeneration units have the same technical abilities as NGCC power plants from a capacity factor standpoint, high utilization of cogeneration units demonstrates that NGCC units can also run at high utilizations.

Currently, many combined cycle units may not run at a high capacity factor because of factors related to economic dispatch, not technical ability. The utilization of all types of power plants is an economic decision based on the market demand, fuel cost, power price, and available generation supply. The demand profile throughout the day, as well as operating response characteristics, have typically favored coal plants running as base load generators with NGCCs running as mid-merit generators. Coal plants have historically had cheaper fuel costs than gas plants and are not quick responders to operational changes, so they often run as baseload power generators. However, since 2009 the U.S. coal fleet has had an average capacity factor less than

70 percent.[26] Given their technical reliability, with the right economic conditions, NGCC plants can compete for base load operations with coal plants, as already demonstrated in 2012.

Some public commentary, particularly in the Northeast, misconstrues EPA's 70 percent target utilization as an assumption that every plant is capable of running at 70 percent every day of the year, concluding that limits on natural gas supply for power generation during peak demand makes it impossible to meet the standard. This conclusion is inappropriate and inconsistent with EPA's analysis. In evaluating feasibility on a unit by unit capacity utilization, EPA should continue to use an average annual approach, consistent with the rule's compliance requirements. Such an approach allows for varying levels of capacity utilization as market conditions dictate – as we mention above, the utilization of all types of power plants is an economic decision based on market demand, fuel cost, power price and available generation supply. In other words, to meet an average 70 percent utilization, a given unit could run at a higher capacity utilization rate over some period of time and at a lower rate or not at all on other days.

In sum, running NGCCs at high utilization rates (>70 percent) is technically feasible and will be done in practice when power generation economics support it.

C. Upstream Methane Emissions Are Not Applicable To BSER for EGUs, And In Any Event Are Projected To Decrease Under the Proposed Rule.

As part of the Regulatory Impact Analysis ("RIA") for the proposed rule, EPA analyzed potential upstream net methane emissions impacts associated with increased use of natural gas in the power sector. EPA's consideration of these impacts was appropriately limited to an appendix to the chapter of the RIA considering economic and energy impacts. CAA section 111(d) provides for state plans to regulate "*any existing source*";[27] EPA cannot include "upstream" emissions in its determination of guidelines for state determination of BSER. The affected sources in this proposed rule are fossil fuel-fired boilers, IGCC units, and stationary gas-fired combustion turbines. Upstream emissions or impacts are not part of the source category sought to be regulated, and EPA has appropriately not considered those impacts in this proposal.

[26] Ventyx Energy Velocity database.

[27] 42 U.S.C. § 7411(d)(1) (Emphasis added).

On the specific analysis EPA performed in this area, ANGA does not agree with EPA's use of the 2013 Greenhouse Gas ("GHG") Emissions Inventory for underlying data in the analysis as opposed to the more recent 2014 GHG Emissions Inventory. While we recognize that EPA addresses a major concern we had with the 2013 Inventory by assuming widespread use of reduced emission completion technology in response to the 2012 Oil and Gas New Source Performance Standards ("NSPS"), we encourage EPA to rely on the most recent inventory given the significant changes to the inventory over the past five years. As we stated in our comments related to the 2014 GHG Emissions Inventory, ANGA does not support the use of the inventory for regulatory purposes and we look forward to continuing to work with EPA to update the inventory to more accurately reflect emissions.

II. Recognition of the Domestic Supply and Availability of Natural Gas

A. EPA Has Appropriately Recognized the Abundant Supply of Domestic Natural Gas.

ANGA has long advocated for EPA to update its assumptions regarding the supply and availability of natural gas. In our comments on the proposed Mercury and Air Toxics Standards, we disagreed with EPA's assertions that "[n]atural gas pipelines are not available in all regions of the U.S. and natural gas may not be available as a fuel for many EGUs" and "[e]ven where pipelines provide access to natural gas, supplies of natural gas may not be adequate, especially during peak demand periods (e.g., the winter heating season)."[28] [29] In those comments, we asked that EPA review recent assessments of historic pipeline development by EIA and projected future pipeline development by the Interstate Natural Gas Association of America ("INGAA") Foundation; as well as assessments of natural gas supply and availability by EIA, the MIT Energy Initiative, and the Potential Gas Committee.[30] [31] [32] [33] [34] However, we noted in our

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[28] Comment submitted by Regina Hopper, President and Chief Executive Officer (CEO), America's Natural Gas Alliance (ANGA) on *Proposed Rule: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*. EPA-HQ-OAR-2009-0234-17810 (August 4, 2011).
[29] 75 *Fed.Reg.* 25046.
[30] Energy Information Agency. *Expansion of the U.S. Natural Gas Pipeline Network: Additions in 2008 and Projects through 2011*. (September 2009), available at ftp://ftp.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2009/pipelinenetwork/pipelinenetwork.pdf
[31] The INGAA Foundation. *North American Natural Gas Midstream Infrastructure Through 2035: A Secure Energy Future: Executive Summary*. (June 28, 2011), available at: http://www.ingaa.org/File.aspx?id=14911

comments on the 2012 GHG power plant NSPS proposal that EPA appropriately updated its approach to recognize the abundance of this valuable domestic resource.[35] Specifically, in the Regulatory Impact Analysis ("RIA") for the 2012 proposed NSPS rule, EPA noted that the current economic advantage of natural gas is "largely due to advances in hydraulic fracturing and horizontal drilling techniques that have opened up new shale gas resources and substantially increased the supply of economically recoverable gas."[36] In the RIA for the NSPS re-proposal, EPA reasserted EIA's projections for natural gas availability and updated its assumptions to reflect EIA's Annual Energy Outlook ("AEO") 2013.[37] Finally, in the RIA for the current section 111(d) proposal, EPA recounts the projections from the 2012 AEO and adds that "EIA's projections of natural gas conditions did not change substantially in AEO 2014 from the AEO 2013, and EIA is still forecasting abundant reserves consistent with the findings from earlier AEOs.[38] EPA further notes that "[r]ecent historical data reported to EIA is also consistent with these trends, with 2013 being the highest year on record for domestic natural gas production."[39]

ANGA asks that EPA continue to use up-to-date assessments of natural gas supply and availability in this and future regulatory actions. We encourage the Agency to further review EIA's AEO 2014.[40] The final release of that assessment projects increased production of natural gas and increased natural gas-fired generation relative to EIA's AEO 2013 used by EPA to calibrate the IPM modeling platform used to evaluate the potential impact of the proposed rule.

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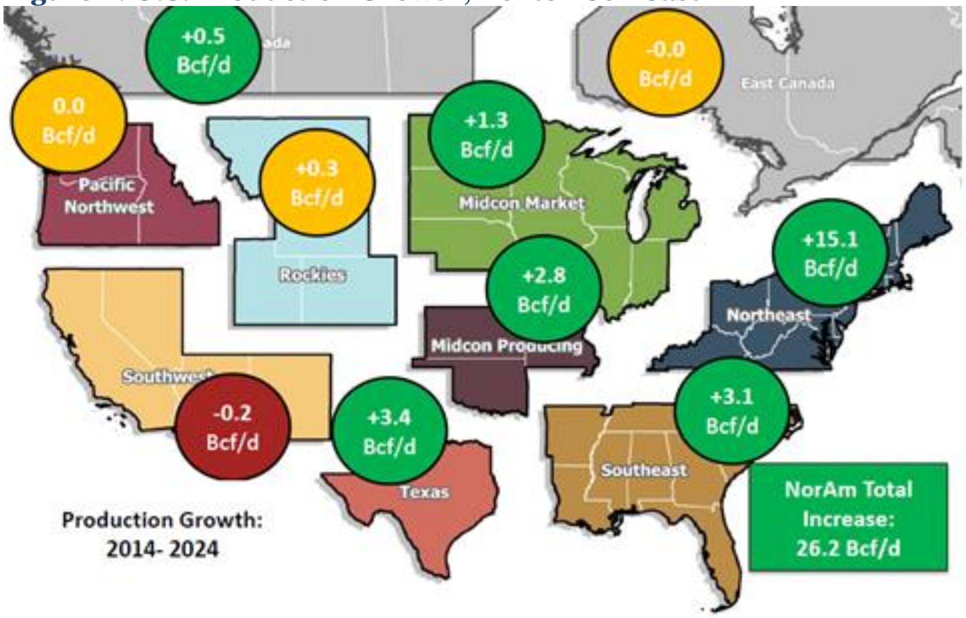
[32] U.S. Energy Information Administration. *Annual Energy Outlook 2011 With Projections to 2035* (April 2011). See also EIA. *Annual Energy Outlook 2012 (Early Release) With Projections to 2035* (January 2012).
[33] MIT Energy Initiative. Final Report, *The Future of Natural Gas – An Interdisciplinary MIT Study,* (June 2011).
[34] Potential Gas Committee, *Potential Supply of Natural Gas in the United States (December 31, 2010)* (April 27, 2011).
[35] Comment submitted by Regina Hopper, President and Chief Executive Officer (CEO), America's Natural Gas Alliance (ANGA) on *Proposed Rule: Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*. EPA-HQ-OAR-2011-0660-9771 (June 22, 2012).
[36] U.S. Environmental Protection Agency. *Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units* EPA-452/R-12-001 (March 2012). At p. 5-2.
[37] U.S. Environmental Protection Agency. *Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units* EPA-452/R-13-003 (September 2013). At p. 64.
[38] U.S. Environmental Protection Agency. *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* EPA-542/R-14-002 (June 2014). At p. 2-24.
[39] *Id*.
[40] Energy Information Agency. *AEO2014* available at http://www.eia.gov/forecasts/aeo.

Figure 2: U.S. Production Growth, Bentek Cell Cast



A recent analysis by Bentek supports the conclusion that natural gas production is expected to grow significantly across the country, as summarized in Figure 2.[41] Such production growth has driven, and is driving, large investments in infrastructure to move gas from supply basins to demand markets. Because much of this increased production will originate from the Northeast producing region, many infrastructure projects are adding bi-directional capability to existing pipelines to increase their operational capacity, as highlighted by the red arrows in Figure 3. This bidirectional feed relieves pipeline capacity constraints and hence creates new pipeline flexibility.[42]

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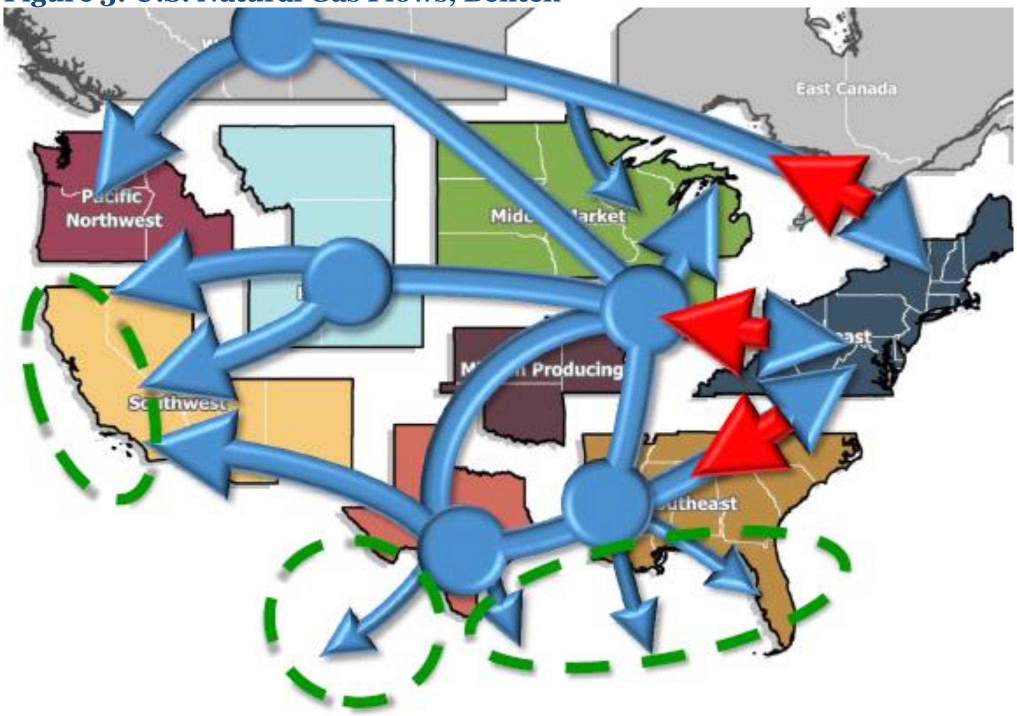
[41] Bentek. *Southeast Market Study (November, 2014).*

[42] This benefit was recognized when the Midcontinent Independent System Operator completed the third and last phase of its evaluation of the ability of Midwestern pipeline infrastructure to support significant replacement of retiring coal capacity. Please refer to the following for additional detail:
Gregory L. Peters, EnVision Energy Solutions, *Phase III: Natural Gas-Fired Electric Power Generation Infrastructure Analysis An Analysis of Pipeline Capacity Availability* (December, 2013).

Figure 3: U.S. Natural Gas Flows, Bentek

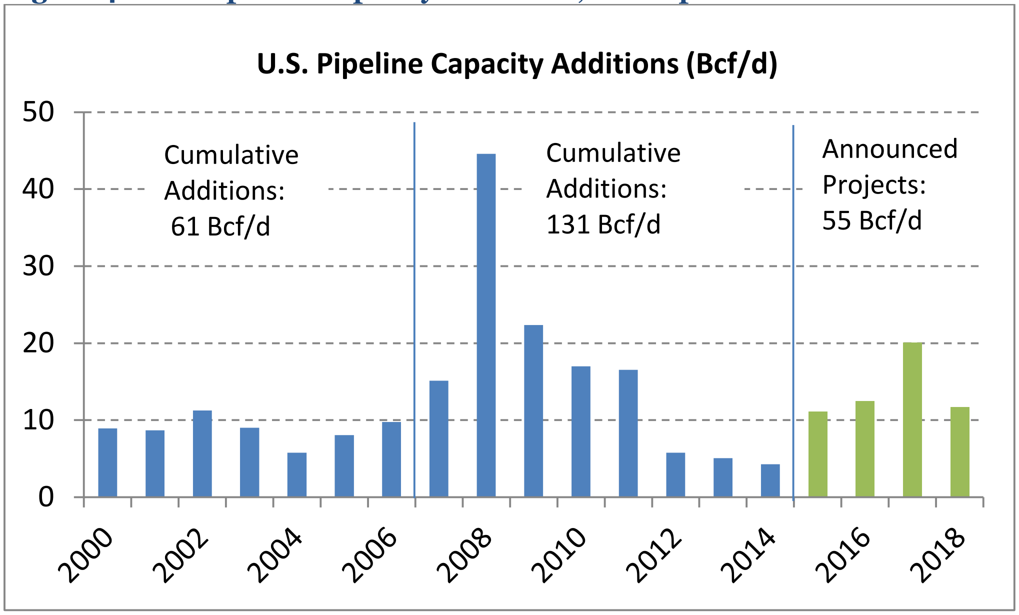


B. Pipeline Capacity Will Continue To Grow.

Natural gas infrastructure additions have been significant since 2007. As depicted in Figure 4 below, cumulative infrastructure additions more than doubled between 2007 and 2013 when compared to the 2000 through 2006 timeframe. Over 55 billion cubic feet per day ("Bcf/d") of additional capacity has been proposed to come online by 2018.[43]

[43] Please see Appendix A for a list of proposed infrastructure projects for 2015-2018.

Figure 4: U.S. Pipeline Capacity Additions, EIA Pipeline Data



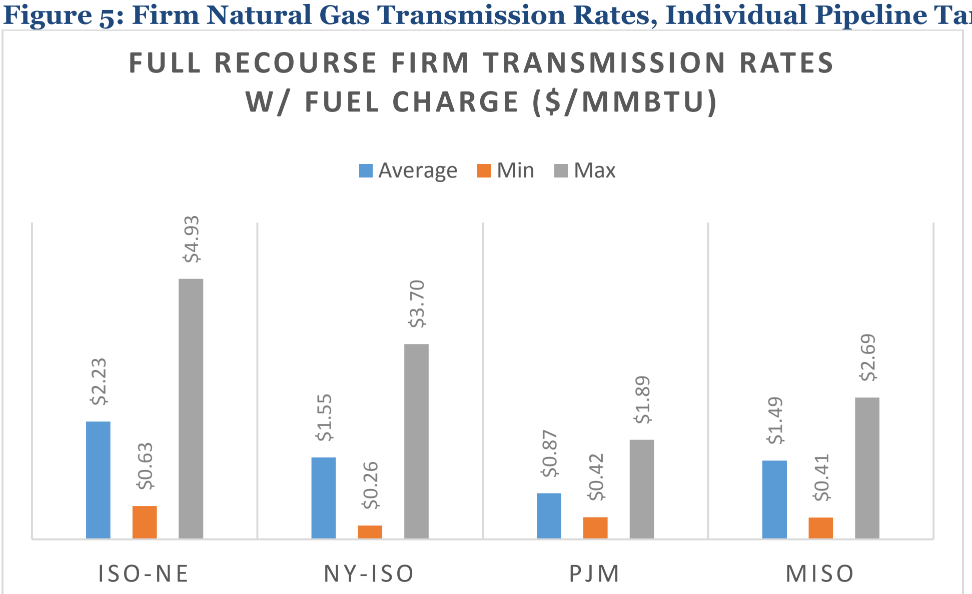
Across the U.S., electric power generators contract differently for delivered natural gas supplies. Depending on the market structure of the region, natural gas-fired generators may rely more heavily on firm contracts or interruptible contracts. In a report to the Eastern Interconnection Planning Collaborative ("EIPC"), Levitan and Associates describe the differences between firm and interruptible gas service and the reason for today's physical gas pipeline system design as follows:

> Interstate pipeline and storage companies offer two basic services: firm transportation and/or storage, and interruptible transportation and/or storage. Pipeline and storage infrastructure capacity is sized strictly to meet the demand of firm customers, that is, those entitlement holders who pay the FERC-authorized cost of service rate to ensure guaranteed deliverability under all circumstances, except force majeure. Historically, force majeure events are rare, and include only the most severe or unusual operating conditions when mainline segments or

compression stations are not available, thereby reducing a pipeline's physical delivery capability.[44]

Electric generation owners who have the ability to recover costs associated with firm contracts often choose to enter into firm contracts. In regions where it is more difficult to recover such costs, interruptible contracts are frequently used. For example, generators who reside in the Northeast or Mid-Atlantic markets will often enter into interruptible contracts. Depending on the region, the utilization of the pipeline capacity, and the specific pipeline tariff, firm pipeline costs vary. Figure 5 shows the average, minimum and maximum costs for firm natural gas fuel delivery in the respective regions based on existing pipeline tariff rates. These rates assume a 100 percent utilization factor of the pipeline. If the utilization factor were lower, then the rates would be higher. Additionally, firm contracts on older pipelines are most often cheaper than contracts with newer pipelines because older pipelines' capital investments are fully depreciated. However, it may be more difficult to contract with older pipelines since they are often fully subscribed.

Figure 5: Firm Natural Gas Transmission Rates, Individual Pipeline Tariffs

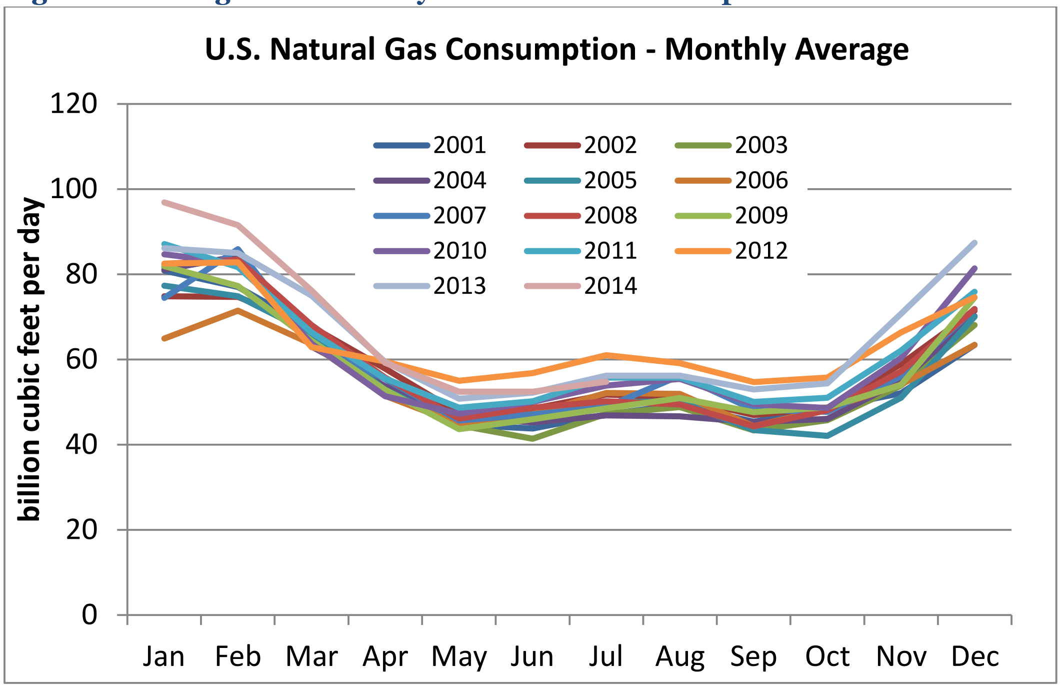


Irrespective of contracts, from a natural gas system perspective the height of natural gas consumption occurs during winter months mainly due to residential and commercial seasonal

[44] Levitan & Associates, Inc. *Gas-Electric Interface Study: Existing Natural Gas-Electric System Interfaces* (February, 2014). At p. 11.

heating needs. As depicted in Figure 6, during non-winter months (defined here as all months excluding January, February and December), natural gas consumption is much lower.[45] Since 2001, U.S. natural gas consumption during non-winter months is 64 percent of the annual maximum consumption, on average.

Figure 6: Average U.S. Monthly Natural Gas Consumption[46]



While New York and New England's pipeline infrastructure is constrained to serve daily peak natural gas demand during winter months, the rest of the U.S. does not suffer such infrastructure constraints. As with all systems delivering energy to consumers during extreme weather events, the system can be stressed; however, these events are infrequent across the years and relatively short in duration. While the 2013-2014 winter severely stressed the electric grid and the natural gas delivery system, no bulk power outages occurred, and natural gas customers utilizing firm contracts did not experience supply curtailments.[47] Given the multiple electric load records set across many regions, and the high generator outages present coupled with record daily gas consumption, the systems in place displayed true resiliency.

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[45] Energy Information Agency. *Natural Gas Consumption by End Use*. (September 2012), available at http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm.
[46] EIA. Natural Gas Consumption by End Use.
[47] Federal Energy Regulatory Commission. *Winter 2013-2014 Operations and Market Performance in RTOs and ISOs* (April, 2014), available at http://www.ferc.gov/CalendarFiles/20140402102127-4-1-14-staff-presentationv2.pdf.

The Federal Energy Regulatory Commission ("FERC") has already stated that the Mid-Atlantic is in a better position to handle a similarly extreme winter season. The Division of Energy Market Oversight at FERC determined that if similar conditions to last winter emerged this winter, Mid-Atlantic demand would be slightly higher; however, natural gas spot prices at certain liquid trading points would likely not be as severe due to new pipeline capacity coming online by the start of winter.[48] This pipeline expansion includes 4.3 Bcf/d of additional capacity targeting both the New York market and relieving producing area constraints in Pennsylvania and Ohio.

When looking across regions more broadly, the following studies support the significant availability of delivered gas supplies for electric power generation:

- The "Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric System Perspective" interim report for the Western Interstate Energy Board found that "existing gas transportation infrastructure will generally be adequate to meet the regional needs of the electric sector except under extreme winter conditions."[49]

- The Electric Reliability Council of Texas ("ERCOT") commissioned a study in 2012 to examine the risk of gas supply curtailment to electric generators within its service. The study found that ERCOTs electric generators' gas supply capacity "is well in excess of their peak natural gas needs."[50]

- The Midcontinent Independent Transmission System Operator ("MISO") commissioned a study to examine the availability of pipeline capacity to serve natural gas-fired generation in its footprint. The study found that, "[o]verall, pipeline capacity in the MISO Midwest is positive and continually improving due to shale gas developments and accommodating pipeline expansions, contract

[48] Federal Energy Regulatory Commission. *Winter 2014-15 Energy Market Assessment* (October, 2014), available at http://www.ferc.gov/market-oversight/reports-analyses/mkt-views/2014/10-16-14-A-3.pdf.
[49] Energy and Environmental Economics, Inc. *Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric System Perspective – Phase I Interim Report* (March, 2014). At p. 174.
[50] Black & Veatch. *Gas Curtailment Risk Study* (March, 2012). At p. 27.

> expirations and the benefits of increased pipeline reticulation underway in the Eastern Interconnect."[51]

Returning to New England's infrastructure issues, several factors make New England unique and an inappropriate example to use for comparison with other regions of the U.S. First, New England does not have the geology to support geologic gas storage like the rest of the U.S. Due to this issue, liquefied natural gas ("LNG") peaking storage facilities are used to manage winter local distribution company loads (mainly residential and commercial customer heating demand).[52] This type of storage is more expensive than geologic storage; hence, if market rules do not allow for cost recovery, it is difficult for customers to afford such services. Second, New England demand is highly seasonal. Because the total gas consumption swings greatly between summer and winter, significant amounts of pipeline capacity are available for electric generators during non-winter months.[53] This seasonal demand profile, coupled with cost recovery challenges in the region's electric market rules reduces the incentive for electric generators to commit to firm pipeline capacity. Third, New England ISO electricity market scheduling differs from that of New York ISO, thus creating a disadvantage for New England because New York is able to procure gas earlier in the day, leaving New England to procure gas in tighter market conditions as the daily gas volumes are sold most heavily in the morning hours.[54] Even with all of these challenges, the incremental pipeline capacity provided by the Algonquin Incremental Market Project ("AIM") is expected to greatly reduce volatility in the region.[55] This project is scheduled to come online in November 2016.

The majority of the infrastructure studies referenced in this section target natural gas availability for gas-fired electric generators on natural gas peak demand days. These studies do not directly assess annual natural gas availability for gas-fired electric generators. Given the often significant availability of delivered natural gas for electric power generation on peak gas

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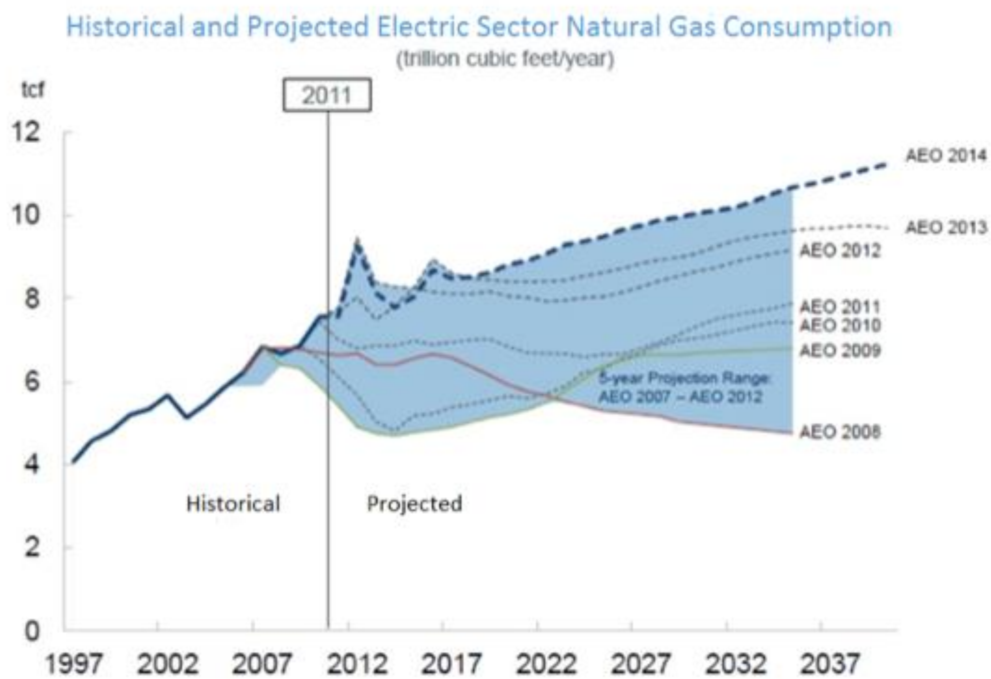
[51] EnVision Energy Solutions. *Phase III: Natural Gas-Fired Electric Power Generation Infrastructure Analysis: An Analysis of Pipeline Capacity Availability: Appendix* (December, 2013). At p. 8.
[52] Northeast Gas Association. *The Role of LNG in the Northeast Natural Gas (and Energy) Market* (August, 2014), available at: http://www.northeastgas.org/about_lng.php.
[53] Energy Information Administration. *Northeast natural gas spot prices particularly sensitive to temperature swings* (August, 2014) available at: http://www.eia.gov/todayinenergy/detail.cfm?id=17491#tabs_SpotPriceSlider-3.
[54] ICF International. *Gas-Fired Power Generation in Eastern New York and its Impact on New England's Gas Supplies* (November, 2013). At p. 4.
[55] Black & Veatch. Natural Gas Infrastructure and Electric Generation: Proposed Solutions for New England (August 2013). At p. 31.

demand days, one can infer an even greater amount of gas available for electric power generation throughout the year.

Figure 7: EIA Projections of Electric Sector Natural Gas Demand



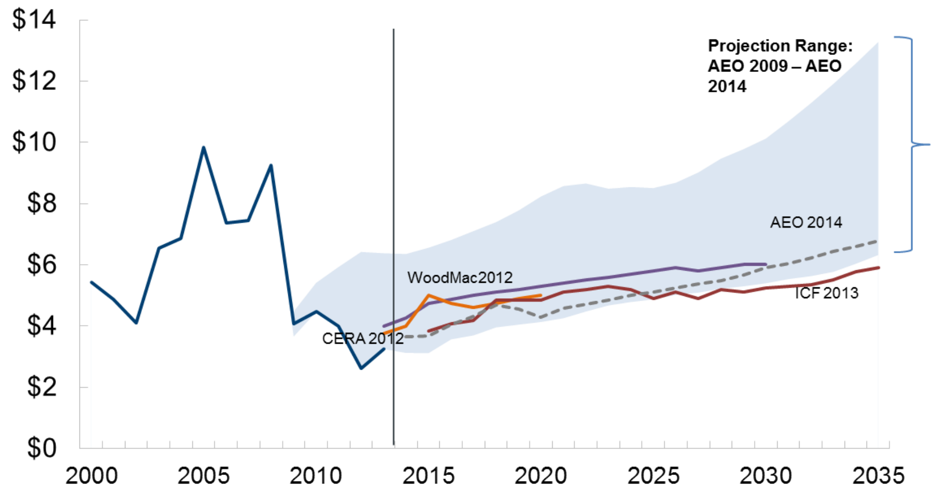
Source: EIA AEO 2007 - 2014

Even absent EPA's proposed section 111(d) rule, analysts predict increased reliance on natural gas within the electric power sector as older, less efficient generating facilities are retired from the system. Figure 7 shows a range of natural gas demand projections for the electric sector developed by the EIA as part of its AEO series. AEO 2008 projected a steady decline in natural gas use by the electric power sector. In contrast, AEO 2014 projected a 48 percent increase in natural gas utilization in the electric sector from 2011 to 2040, up from a projected 25 percent increase in AEO 2013. This shift is due to the expected retirement of coal-fired and oil-fired power plants and to confidence in the long term outlook for natural gas price and supply.

C. Abundant And Stable Gas Supplies Encourage Stable Markets.

Concerns that increased natural gas demand "could add upward pressure on natural gas prices" are unwarranted.[56] Figure 8 shows a range of different price forecasts relative to EIA's outlook since 2009. As EPA notes in the RIA, "current and projected natural gas prices are considerably lower than the prices observed over the past decade."[57] Moreover, as discussed above, recent EIA projections support continued growth in natural gas supply, and natural gas pipelines and infrastructure have the capacity to support this growth and quickly ramp up production as needed. The vast supplies of natural gas as a result of U.S. shale plays mean that there is enough natural gas available to power and heat homes and businesses and run vehicles for generations to come. A stable and abundant supply of natural gas will provide for markets, making natural gas an attractive option for power generation, transportation, industrial and residential uses.

Figure 8: Henry Hub Natural Gas Price (2011$/MMBtu)



ANGA disagrees with assertions that the increased use of natural gas in the power sector will result in increased natural gas price volatility. Natural gas price volatility is defined as "sustained, unpredictable price movements" that cause uncertainty for both users and producers

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[56] *See* U.S. EPA, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Notice of data availability* ("NODA"), 79 Fed. Reg. 64,543, 64,549 (Oct. 30, 2014).

[57] U.S. Environmental Protection Agency. *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* EPA-542/R-14-002 (June 2014). At p. 2.23.

of natural gas.[58] Expected seasonal price fluctuations (e.g., due to greater demand for heating) do not constitute "volatility" in the proper use of the term.

Apart from localized price impacts experienced in the Northeast during the polar vortex as a result of regional pipeline constraints, since 2000, the U.S. has experienced three noteworthy periods of price volatility: (1) the California energy crisis in 2000-2001; (2) the hurricanes of 2005; and (3) the price spike in 2008. Each of these events provided a different lesson in potential causes of price volatility: deliverability issues, supply shocks, and erratic market behavior. And in each case, as described below, circumstances have changed such that similar events, if they occurred today, would not lead to similar volatility.

1. In the case of the California energy crisis, a steep rise in demand for natural gas-fired power generation was followed by erratic trading behavior and asymmetric management of physical infrastructure. This behavior significantly hindered "deliverability" – the ability of suppliers to meet natural gas demand.

    - As described previously in this section, deliverability of gas throughout the U.S. has improved markedly since 2000, with over 150 Bcf/d of pipeline capacity added from 2001 to 2011. The industry has continued to invest in additional pipeline capacity, adding 2,400 miles in 2011 alone. A robust pipeline infrastructure and expanded storage capacity ensures that natural gas is available when and where it is needed, and helps avert price spikes caused by deliverability problems.

2. In the second period of price volatility, extreme weather conditions knocked out production and transportation facilities and caused a sudden, prolonged loss of 6 Bcf/d of natural gas production from the Gulf of Mexico.

    - The price volatility caused by Hurricane Katrina is indicative of a supply problem that bears no resemblance to the supply impact of potential expanded power sector demand. Long lead times for compliance with the proposed

[58] Price Instability in the U.S. Natural Gas Industry Historical Perspective and Overview, July 15, 2010. Prepared for The Task Force on Natural Gas Market Stability, Rick Smead, Navigant Consulting.

greenhouse gas regulations will give the market several years to anticipate the demand increase. With a hurricane, the market has only days to react. In addition, were another hurricane or major weather event to occur, we would expect very different fuel supply response. Increasing onshore unconventional natural gas production in diverse geographic locations combined with significant infrastructure investment to move that gas to markets has resulted in diversified supplies and redundancy in the system that would minimize the impact of regional weather events.

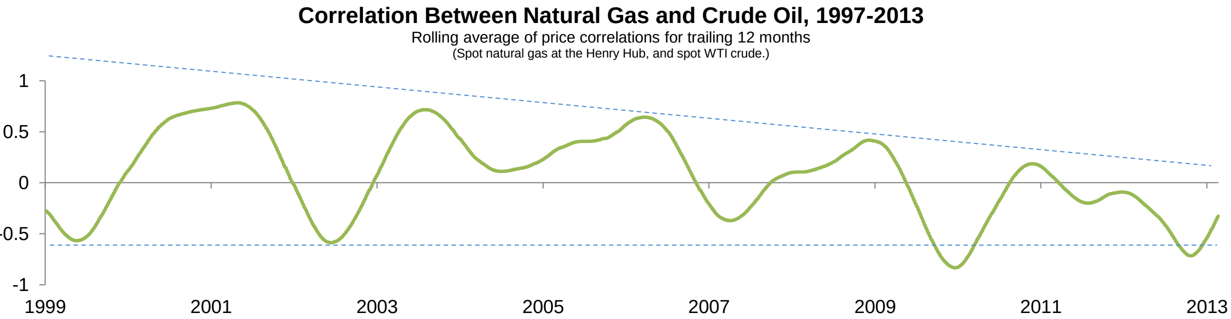
3. During the third period, a natural gas price rise followed general global commodity price inflation. Prices rose steeply in everything from oil to wheat, and then returned back to pre-inflation levels.[59]

    - The market's reaction to the global commodity price bubble was explained in part by an expectation on the part of commodity traders that natural gas and oil prices were inextricably linked. But in the ensuing years, natural gas and oil prices in the U.S. have definitively decoupled from one another. The narrowing of the correlation range as shown in Figure 9 demonstrates that natural gas prices have become less correlated with the price of oil over the past 15 years. In today's market, a dramatic and sharp increase in the price of oil would not have the same impact on the price of natural gas as it would have had historically.

Outside of these three anomalous events, prices in the period from 2000 to 2010 were relatively stable, and considering the mitigating factors discussed above, there is nothing to suggest that increased use of natural gas in the power sector would cause a market disruption similar to these episodes. Furthermore, this confirms that natural gas will remain a stable, reliable fuel source such that it is appropriate to rely increasingly on the fuel for power generation.

[59] Ibid. The Smead report contains a lengthy discussion of the history of price volatility.

Figure 9: Correlation between natural gas and crude oil, 1997-2013



In addition to the changes to deliverability and market pricing, production from shale formations distributed throughout the U.S. has fundamentally changed the industry's ability to respond to price signals. In conventional production, higher prices drive producers to increase exploration, but the link and timing to actual production is lagged and imperfect. Production from shale formations reduces exploration risk significantly, and allows producers to increase production far more responsively. Given the size of the technically recoverable resources in the U.S., producers will be able to respond quickly to market signals in order to meet increasing demand. With the ability to react efficiently to price signals, production volumes should further significantly reduce the risk of sustained, unpredictable price movements. This is a major benefit of the size of the technically recoverable total natural gas resource base.

The rapid replenishment of natural gas storage levels this past injection season is a perfect, real-world example of how quickly producers are able to respond to market needs. As mentioned previously, the 2013-2014 winter was severe. The rare, 1-in-30 winter caused natural gas storage volumes to be depleted to levels not seen since 2003. However, due to significant production increases from natural gas producers, storage injections set weekly records throughout the injection season. In fact, the April 1 to October 31, 2014 total injection volume set a new season record at 2,734 Bcf.[60]

ANGA rejects claims that increased use of natural gas in the power sector will increase natural gas price volatility. Most importantly, ANGA rejects claims that natural gas is inherently volatile and should not be increasingly relied upon for power generation. None of the root causes of volatility would be exacerbated by increased use of gas in the power sector. Moreover,

[60] Energy Information Administration. *After record injections, natural gas storage levels now within 7% of 5-year average* (November 7, 2014), available at: http://www.eia.gov/todayinenergy/detail.cfm?id=18731

natural gas producers and pipeline companies have invested heavily to enhance gas deliverability and mitigate supply shocks.

III. EPA's Authority to Establish Standards of Performance for Existing EGUs And To Approve State Plans for Compliance.

A. In Determining What Standard Qualifies As BSER, EPA May Not Consider "New" Source Emissions.

EPA has requested comment both in its original proposal and its subsequent Notice of Data Availability (NODA) on how new NGCC units and other new fossil fuel-fired units should be accounted for in setting section 111(d) BSER standards and evaluating state compliance plans.[61] EPA has neither the authority to subject new units to regulation under section 111(d), nor the authority to consider new units in determining BSER for existing sources.

The statute is clear. Section 111 separately defines *new* and *existing* sources and establishes two distinct processes for the regulation of them.[62] "New" sources are regulated under section 111(b); "existing" sources are regulated under section 111(d). EPA must regulate each type of source under the corresponding provision, and no interpretation to the contrary can be reconciled with the plain language of the statute. Thus, *Chevron* deference principles do not apply: EPA has no discretion to circumvent Congress's clear directive by regulating new sources under section 111(d).

Because new sources cannot be subject to regulation under section 111(d), EPA may not consider the construction of, or emissions from, new EGUs in setting the BSER standard for existing sources. Indeed, existing sources are not even subject to regulation until after EPA has adopted standards for new sources within the same source category.[63] Further, and as discussed more at length below, the "best system of emissions reduction" is limited to emissions reduction measures that can be achieved at a source or within the source category.[64] Thus, emissions reductions achieved through *new* sources, which are outside the scope of sources regulated under section 111(d), cannot be included in EPA's BSER determination.

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[61] *See* 79 Fed. Reg. at 34,876-77; 79 Fed. Reg. at 64,550.
[62] *Contrast* 42 U.S.C. § 7411(b) *and* 42 U.S.C. § 7411(d); *see also id*. §§ 7411(a)(2), (6).
[63] *Id*. § 7411(d)(1).
[64] *See id*. (requiring the Administrator to issue regulations establishing "a standard of performance *for any existing source of air pollution*" (emphasis added)).

This limit on EPA's authority extends to EPA's promulgation of emission guidelines for state compliance plans and what sources states may be required to control as part of such plans. Specifically, some have raised questions as to how emissions from new sources should be treated in states where the 111(d) emission standard (*i.e.*, the emission rate defined by EPA as applicable in the state) is lower than the 111(b) emissions rate for new sources. The implication is that these new sources should be subject to additional controls since their emission rate would be above that which is applied to existing sources generally. However, it would be a violation of the statute for EPA to consider new sources regulated under section 111(b) for purposes of defining what emission rate would apply in a state under section 111(d), or for EPA to expand the scope of sources that would be subject to an section 111(d) emission rate or other control in a state plan.

Instead, the CAA requires EPA to regulate each type of source ("new" or "existing") under the corresponding provisions of section 111 and no interpretation to the contrary can be reconciled with the plain language of that statute. EPA cannot require that new sources (*i.e.* 111(b) sources) or emissions from new sources be included or addressed in a state plan. Apart from being at direct odds with the statutory language of the CAA, any interpretation that required new source emissions to be counted towards compliance would needlessly constrain a state's flexibility to meet increased electricity demand in the most cost-effective manner.

B. EPA Should Retain the Rate-Based Standard Contemplated in the Proposed Rule.

For each state, EPA's proposed rule adopts a rate-based emission guideline based on the adjusted output-weighted-average emission rate in pounds of emissions per megawatt-hour ("lbs/MWh") at the point of delivery to the transmission grid. This rate-based approach to regulation under section 111(d) is both consistent with the statute and also best accommodates states' fluctuating needs and anticipated growth in electricity demand.

Traditionally, almost all standards adopted under section 111 have been rate-based, and EPA is certainly not required by the statute to convert its rate-based standard into a mass-based requirement. Indeed, unlike other areas of the CAA (*e.g.*, the Title IV acid rain program) the entire section 111 program, with its focus on the "best system of emission reduction," is standard-based rather than oriented to any defined outcome or limit on emissions volume. While this does not preclude the use of allowance programs or other systems of emission reduction under section 111(d), there can be no question that a rate-based program adheres to the statutory language, and indeed does so in a way that offers increased flexibility and certainty. Specifically, EPA's proposed rate-based approach allows states to develop rigorous emission-reduction measures while allowing states the flexibility they need to accommodate clean economic growth and meet new electricity demand. Such an approach ensures significant emission reductions without stifling the manufacturing renaissance that is currently underway in the United States, as well as related state efforts to grow the economy across various industries with heavy electricity demands. This outcome is most consistent with one of the key objectives of the proposed rule: that is, allowing industrial growth to flourish in the United States while protecting the environment.[65] In this regard, domestic economic growth is likely to reduce global CO_2 emissions by not "outsourcing" U.S. industrial activity and by shifting a greater share of industry to clean-burning, natural gas-powered operation in the United States. For example, while the U.S. electric sector had an average carbon intensity of 1,109 lb CO_2/MWh in 2011, the electric sectors in China and India had average carbon intensities of 1,684 lb CO_2/MWh and 1,887 lb CO_2/MWh, respectively.[66]

Advocates for a mass-based standard suggest that such an approach is necessary to facilitate a workable market-based trading system. This argument, however, is a red herring. While structured somewhat differently, a market-based trading system can be implemented under a rate-based approach without the risk of limiting economic growth through a cap on emissions. As described by researchers at Resources for the Future ("RFF") in a 2012 paper on the topic, under a rate-based trading system the regulator "sets a performance standard, but allows emitters to trade so that it is achieved on a sector-wide, rather than individual, basis."[67] States that establish such a program would credit qualifying resources below the performance standard and allow them to sell credits to affected sources above the performance standard. The researchers at RFF found that rate-based trading systems are "almost certainly legal, are both administratively

[65] 79 Fed. Reg. at 34,935 (citing Executive Order 13563).
[66] International Energy Agency. *CO_2 Emissions from Fuel Combustion*. 2013. *Available at* http://www.iea.org/publications/freepublications/publication/co2emissionsfromfuelcombustionhighlights2013.pdf.
[67] Dallas Burtraw, Art Fraas, and Nathan Richardson (February 2012). "Tradable Standards for Clean Air Act Carbon Policy" *Resources for the Future Discussion Paper.* RFF DP 12-05. *Available at* http://www.rff.org/rff/Documents/RFF-DP-12-05.pdf.

and politically viable, and are relatively cost-effective."[68] Among other benefits, a rate-based system can be implemented without requiring policymakers to make assumptions about the level of required future generation and the rate-based system eliminates the need for the controversial process of allocating emission allowances.

IV. EPA's BSER Determination Relative To State Plans Is Constrained By the Statutory Language of Section 111.

A. Evaluation and Determination of BSER Must Focus on Covered Sources.

Section 111 of the Clean Air Act authorizes EPA to develop regulations for categories of stationary sources determined by EPA to contribute significantly to "air pollution that may reasonably be anticipated to endanger public health or welfare."[69] Section 111(d) of the Clean Air Act specifically addresses regulations for existing sources within a designated source category. Under that section, EPA must establish a procedure for states to develop and submit for EPA approval a plan that establishes "standards of performance" for air pollutants emitted from existing sources.[70] The Clean Air Act defines a "standard of performance" as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[71] This standard is commonly referred to as BSER.[72]

BSER does not include measures that focus on sources (*i.e.*, designated facilities) outside of those source categories regulated under section 111. Thus, EPA section 111(d) rulemaking must establish BSER exclusively on the basis of covered source categories, such as fossil fuel-fired boilers or stationary natural gas-fired combustion turbines.

The statutory structure of section 111 confirms that BSER must be based on section 111 source categories. Before regulating any source under section 111, EPA must first have

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68 *Id*. at 2.
69 42 U.S.C. § 7411(b)(1)(A)-(B).
70 42 U.S.C. § 7411(d).
71 42 U.S.C. § 7411(a)(1) (emphasis added).
72 *See* 40 C.F.R. §60.22. (EPA's section 111(d) implementing regulations require that EPA must establish "emission guidelines" that reflect "the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities.").

identified that source category as one which "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[73] The statute then instructs EPA to issue standards of performance "for new sources within such categor[ies]." With regard to existing sources, standards of performance are required for those sources "to which a standard of performance under [section 111] would apply *if such existing source were a new source*."[74] (Emphasis added). This statutory focus on emissions from sources within EPA's listed source categories necessarily constrains EPA's regulatory authority under section 111 and expresses Congress's intent that EPA establish standards of performance based only on emission reductions that can be achieved and implemented at the covered sources themselves.

EPA has interpreted and applied BSER in this fashion, both under the current statutory definition of "standard of performance" and the predecessor standard for new sources, referred to as "best demonstrated technology" or "BDT." The "best demonstrated technology" standard inherently recognized that emission reductions were to be achieved through strategies achieved at a covered source. The same is true of the BSER standard. As described by the Agency:

> EPA typically conducts a technology review that identifies what emission reduction systems exist and how much they reduce air pollution in practice. This allows EPA to identify potential emission limits. Next, EPA evaluates each limit in conjunction with costs, secondary air benefits (or disbenefits) resulting from energy requirements, and non-air quality impacts such as solid waste generation.[75]

Once emission standards have been determined, EPA then interprets the CAA to allow for flexibility in meeting the standard. For example, in its 2012 new source performance standards for petroleum refineries, EPA explains that:

> [a]s was done previously in analyzing BDT, the EPA uses available information and considers the emissions reductions achieved by the different systems available and the costs of achieving those reductions. The EPA also considers the "other factors" prescribed by the statute in its BSER analysis. After considering all of this information, the EPA then

[73] 42 U.S.C. § 7411(b)(1)(A).
[74] *Id*. §§ 7411(b)(1)(B), (d)(1).
[75] EPA, Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act, at 2.

> establishes the appropriate standard representative of BSER. <u>*Sources*</u> *may use whatever system meets the standard*.[76]

Likewise, in EPA's recent proposed standards for new power plants, EPA recognized that "sources generally can select any measure or combination of measures that will achieve the" standard of performance.[77]

Such characterizations of BSER and its application properly underscore the central role of covered "sources" to regulation under section 111(d). While EPA may consider a variety of unit- or source category-specific emission reduction strategies, which may reflect the "best system of emission reduction," any such system (and resulting standard of performance) must ultimately be implemented and achieved amongst *those sources regulated within the relevant source category*.

Any interpretation of EPA's authority that would allow the Agency to consider non-covered sources when making BSER determinations is not only contrary to the statute and EPA's prior practice but also flies in the face of Supreme Court precedent. In its recent decision in *Utility Air Regulatory Group v. EPA* ("*UARG*"), the Supreme Court cautioned against such "enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization."[78] The Court also expressed "skepticism" over interpretation of ambiguous CAA language as authorizing "unheralded" action with sweeping economic implications.[79] Here, absent any clear statutory language or other directive from Congress in section 111, it is likewise unreasonable under *UARG* for EPA to interpret BSER as enveloping sources and activities that are not subject to or "covered by" standards of performance.

This distinction is abundantly clear with respect to "sources" or activities that do not directly emit air pollution. Section 111(a) defines an "existing source" to mean "any stationary source other than a new source." Section 111(a) then further defines a "stationary source" as "any building, structure, facility, or installation *which emits or may emit any air pollutant*" (emphasis added). Accordingly, in evaluating and determining BSER for existing sources,[80]

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[76] 77 Fed. Reg. at 56426 (emphasis added).
[77] 79 Fed. Reg. 1430, 1444 (Jan. 8, 2014).
[78] 134 S. Ct. 2427, 2444 (2014).
[79] *Id*.
[80] CAA section 111(a) similarly defines a "new source" to mean "any stationary source."

EPA may only consider emissions reductions achievable at and through sources covered under section 111. That is, EPA may only consider sources that actually emit "any air pollutant" in establishing BSER.

B. EPA Cannot Establish State Guidelines It Has No Authority to Enforce.

As noted above, EPA cannot establish emission guidelines beyond the source categories that are subject to regulation under section 111, specifically for sources that do not emit air pollution or could not otherwise be regulated under the CAA. Accordingly, EPA also cannot establish emission guidelines for state plans that are beyond its own authority to enforce. EPA's authority derives from the CAA and cannot extend beyond its bounds.

EPA states that it is "proposing to interpret section 111 as allowing state section 111(d) plans to include measures that are neither standards of performance nor measures that implement or enforce those standards, provided that the measures reduce CO_2 emissions from affected sources."[81] Further, EPA indicates that such measures would be federally enforceable if included in an approved plan.[82] Thus, EPA is effectively asserting that if any control measure or action affects EGU CO_2 emissions, directly or indirectly, it is within reach of the Agency's authority under section 111. Such an expansive interpretation of section 111 cannot withstand judicial scrutiny.

In *Massachusetts v. EPA*, the Supreme Court indicated that EPA's decision to regulate emissions under the CAA "must conform to the authorizing statute."[83] But in the proposed rule, EPA asserts that it can require states to adopt measures to control CO_2 emissions on the basis of CAA standards that are not "standards of performance," that is to say, standards or requirements that are not authorized under section 111(d). EPA simply cannot require states to adopt measures that would not be permissible if EPA attempted to promulgate such standards directly. In doing so, EPA conflates a state's authority under CAA section 116 to adopt standards or emission limitations that are more stringent than standards or limitations that EPA promulgates with its own, limited authority to act within the bounds established by the CAA.

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[81] 79 Fed. Reg. at 34,903.
[82] *Id.*
[83] 127 S. Ct. 1438, 1462 (2007).

This “end justifies the means” interpretation of statutory authority to regulate CO_2 is without a basis in the CAA or the applicable case law. It also runs contrary to the Supreme Court’s caution in *UARG* against “an enormous and transformative expansion in EPA’s regulatory authority without clear congressional authorization.”[84]

C. EPA’s Inability To Independently and Directly Enforce Building Blocks 3 and 4 Demonstrate That Those Emission Reduction Measures Must Not Be Considered Part of BSER.

In contrast to emission reduction measures and reductions that can be achieved by covered sources, any determination of BSER on the basis of proposed Building Blocks 3 and 4 would render EPA’s emission guidelines in excess of statutory authority. Building Blocks 3 and 4 respectively contemplate displacement of fossil fuel generation by renewable or nuclear resources and demand-side energy efficiency measures. Such emission reduction strategies – both of which depend on emission reductions from sources or actors other than fossil fuel-fired EGU sources expressly subject to regulation under section 111 – overreach and are not supportable as a basis for BSER.

As discussed above, EPA has no authority to determine BSER on the basis of measures that cannot be achieved and implemented within the regulated section 111 source categories.[85] Renewable and nuclear generation resources are not classified under regulated section 111 source categories, nor could they be, for neither “causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.”[86] Demand-side energy efficiency measures similarly do not fall within any regulated section 111 source category and cannot be implemented and achieved amongst regulated sources. Despite whatever authority states might otherwise have to pursue such strategies, EPA itself may not look to renewables, nuclear generation, or demand-side measures as a basis for its determination of what level of emission reduction qualifies as BSER.

The inappropriateness of Building Blocks 3 and 4 further follows from section 111(d)(2) of the statute, which requires EPA to establish a federal section 111(d) plan for any state that

[84] 134 S. Ct. 2427, 2444 (2014).
[85] *See supra*, Sections IV(A)-(B).
[86] 42 U.S.C. § 7411(b)(1)(A).

fails to submit a "satisfactory" plan of its own.[87] EPA has no authority or ability to require increased renewable or nuclear generation or to implement demand-side energy efficiency programs. These are traditional areas of state legislation and regulation—and areas over which EPA and the regulated section 111 source categories have no control.[88] As a result, if a federal plan were to apply, affected EGUs subject to a BSER standard based on such federally unenforceable programs or activities would bear the full stringency of the resulting limits, and therefore would be forced to limit generation in order to achieve compliance. This in turn threatens the reliability of the electricity grid, a result incompatible with BSER's express consideration of "energy requirements" and the foundational prerequisite that standards be "adequately demonstrated."[89] EPA may not stretch its authority to extend to regulation of resources and activities over which it has no jurisdiction.[90] Because any "system" of emission reduction that reaches beyond EPA's regulated source categories cannot be implemented by EPA, neither can it satisfy BSER when establishing emission guidelines for state compliance in the first place.

D. Energy Efficiency Reductions Intended To Achieve Compliance with EPA Emission Guidelines Must Be Real and Verifiable.

We recognize that energy efficiency plays and important role in an "all the above" energy plan and that many states and utilities have valuable demand side energy efficiency programs. The incorporation of these valuable programs into regulations under the Clean Air Act requires consideration that goes beyond the overall merits of the programs and their goals. As previously stated, EPA has no legal authority to include energy efficiency measures in its calculation of

[87] *Id*. § 7411(d)(2)(A).
[88] Section 103(g) of the CAA confers on EPA limited authority to address energy conservation with respect to research and other *non-regulatory* activities. 42 U.S.C. § 7403(g)(1). EPA has relied upon this authority in carrying out its Energy Star Program, EPA's flagship effort to reduce consumer electricity demand, and has generally acted through voluntary public/private partnerships to promote energy efficiency. In 2005, Congress expressly authorized the Energy Star Program, specifically conferring on EPA specific energy conservation authority. *See* Energy Policy Act of 2005, Pub. L. No. 109-58, § 131, 119 Stat. 594, 620-21 (2005). Where Congress has delegated such specific and limited authority, EPA cannot presume that it has any broader authority to direct energy conservation. *Cf. Am. Petroleum Inst. v. EPA*, 52 F.3d 1113, 1119 (D.C. Cir. 1995) ("EPA cannot rely on its general authority to make rules necessary to carry out its functions when a specific statutory directive defines the relevant functions of EPA in a particular area."); *Am. Petroleum Inst. v. EPA*, 706 F.3d 474, 479 (D.C. Cir. 2013) ("[A] broad programmatic objective cannot trump specific instructions."). As such, EPA has no authority to require energy efficiency measures through 111(d) or other regulatory provisions.
[89] 42 U.S.C. § 7411(a)(1).
[90] *See Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216, 221 (D.C. Cir. 2014) (concluding that agency could not read its authority to "'lure' non-jurisdictional resources" into its regulatory sweep).

state goals under section 111(d). However, standard aside, should states elect to include these energy efficiency programs in their compliance plans, EPA must ensure that claimed energy efficiency reductions are real, verifiable, and based on consistent methodology. These "reductions" are effectively credits for energy not used – and in any circumstance where you are measuring and assigning credit for something that did not occur, care must be taken to ensure the "non-occurrence" is in fact real and resulting from a particular action taken or program developed to incent the "non-occurrence."

As recognized above, states enjoy considerable flexibility in developing section 111(d) state plans and devising strategies for compliance with EPA emission guidelines and thus may rely on any combination of measures to achieve required emission reductions. However, while a state may claim emission reductions through demand-side energy efficiency programs or measures, EPA may not approve a state plan unless energy efficiency-related emission reductions claimed are both real and verifiable. Moreover, states should recognize that the costs of many energy efficiency measures remain uncertain.

Energy efficiency savings can be difficult to quantify. Uncertainties in evaluating energy efficiency measures include, for example: the costs of energy efficiency savings; the inherent level of energy efficiency independently attributable to consumer preferences; the extent and duration of energy savings given the uncertain life span of electric appliances; and the ability to predict and quantify the effect of consumer rebates, energy audits, or other energy efficiency programs on consumer choice. Indeed, EPA recognizes in the proposed rule that, notwithstanding the widespread use of common measurement practices, there can be "significant differences in claimed energy savings values for similar energy efficiency measures between states and utilities, even when the same measure type is installed under otherwise identical circumstances."[91]

The approval and implementation of any state plan lacking adequate criteria to ensure that emission reductions are real and verifiable would be contrary to both section 111 and EPA's implementing regulations. Under the statute, states are required to submit to EPA "satisfactory"

[91] 79 Fed. Reg. at 34920.

state plan for compliance with performance standards.[92] A state plan that includes unverified energy efficiency measures would not meet this standard.[93] Without rigorous review of energy efficiency measures using consistent, clear, and measurable criteria, claimed emission reductions may not occur, or occur in the timeframe predicted. Such a result undermines Congress's statutory intent that state plans be "satisfactory" and that BSER be adequately demonstrated, and would stand in stark contrast to the real, quantifiable emission reductions achievable through increased reliance on clean-burning natural gas resources.

Under the proposed rule, states would be required to submit an evaluation, measurement, and verification ("EM&V") plan that would "specify the analytic methods, assumptions, and data sources that the state will employ during the state plan performance periods to determine the energy savings and energy generation related to [renewable energy] and demand-side [energy efficiency] measures" and that this plan would be subject to EPA approval.[94] EPA states that it "intends to develop guidance for evaluation, monitoring, and verification (EM&V) of renewable energy and demand-side energy efficiency programs and measures incorporated in state plans."[95] The proposed rule itself, however, sets forth no firm criteria for evaluating energy efficiency programs and EM&V plans and for determining whether they comport with section 111(d).

EPA's State Plan Considerations Technical Support Document ("TSD") provides some discussion of the range of potential EM&V plan types and potential EPA approval criteria.[96] However, EPA has not yet provided sufficient support for how it will ensure rigorous assessment of state energy efficiency programs and EM&V plans. For example, EPA takes the position that any EM&V plan must consider the level of certainty in evaluating expected energy efficiency savings but also must balance the degree of certainty against investments of time and money needed to obtain such certainty.[97] In any final rule, and in approving any state section 111(d) plan, EPA must ensure that claimed energy efficiency savings are reliably demonstrated and

[92] 42 U.S.C. § 7411(d)(2)(A).
[93] *See* 40 C.F.R. § 60.21(c) (a section 111(d) plan both establishes emission standards and "provides for the implementation and enforcement of such emission standards"); *id*. § 60.24(b)(2) (requiring state plans to include "[t]est methods and procedures for determining compliance with the emission standards").
[94] 79 Fed. Reg. at 34920.
[95] *Id*. at 34913.
[96] U.S. EPA, State Plan Considerations Technical Support Document ("TSD") at 34 (June 2014) [Dkt. No. EPA-HQ-OAR-2013-0602-0463].
[97] *Id*. at 46.

verified on the basis of consistent methodology.[98] In other words, the degree of certainty required is not a negotiable commodity; it must exist at a level of rigor and support that allows for its approval.

EPA also states, both in the proposed rule and TSD, that it intends to allow wide flexibility in selection of energy efficiency measures but that measures for which EM&V standards and procedures are not as well developed may require additional documentation.[99] EPA should provide guidance identifying specific, consistent approval criteria based on sound technical support to ensure that all energy efficiency programs and measures included in a state plan are proven to a required level of certainty. If the ability to evaluate some types of energy efficiency measures is insufficiently established, such measures may not be used as a basis for a state's section 111(d) compliance or approved as part of its state plan. Moreover, without specific guidance on EM&V, it is impossible to evaluate EPA's finding that all states can reach annual energy efficiency levels of 1.5 percent of in-state sales. At a minimum, EPA will need to evaluate this level of potential savings against robust EM&V guidance before finalizing the rule as proposed.

Finally, in devising and implementing state plans for compliance, states should keep in mind that the costs of many energy efficiency measures remain largely uncertain, particularly in the absence of EM&V guidance that defines the universe of acceptable, quantified measures. As the proposed rule currently stands, there is no reliable cost analysis with respect to potential energy efficiency measures. Thus, there is simply insufficient data and information in the record to support the cost-effectiveness of emission reductions from potential energy efficiency measures.

We are particularly concerned about the way that EPA modeled energy efficiency in IPM. According to the Regulatory Impact Assessment, "the fixed total electricity demand in IPM was adjusted exogenously to reflect the estimated future-year energy savings."[100] This

[98] *Id*. at 55 (describing the specification of minimum precision and accuracy levels as one potential approach that might be adopted in EPA's final EM&V requirements and state plan guidance).
[99] *Id*. at 50; *see also* 79 Fed. Reg. at 34921.
[100] U.S. Environmental Protection Agency. *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* EPA-542/R-14-002 (June 2014). At p. 3-15.

means that EPA assumed the significant levels of energy efficiency it identified were always the least cost compliance approach. This is an inappropriate assumption given the uncertainty associated with what may or may not qualify as energy efficiency and the absence of the availability of such measures within each state. We believe this is particularly important for states to consider when establishing compliance plans and, at a minimum, we believe that if energy efficiency is included in a compliance plan the level of energy efficiency should not be mandated. This avoids the potential of making rule compliance, and ultimately customer electricity, more expensive.

In sum, EPA should provide additional guidance for how it will go about assessing energy efficiency programs and EM&V provisions to verify a state's ability to achieve and implement claimed emission reductions for purposes of state plan approval. To ensure meaningful consideration of such guidance and its implications for the EPA's promulgation of section 111(d) emission guidelines, EPA further must ensure that such guidance is proposed and finalized following public comment prior to issuance of any final rule.

E. EPA May Combine the NSPS Subpart Da and KKKK Source Categories for Purposes of Establishing Emission Guidelines for Fossil Fuel-Fired EGUs Under Section 111(d).

EPA's approach in the proposed rule would combine existing sources under NSPS Subparts Da and KKKK, and would apply a common set of emission guidelines under a new Subpart UUUU.[101] Such combination of section 111(b) source categories for purposes of section 111(d) is allowed under the statute and appropriate in the context of this rulemaking.

Under section 111(b)(1)(A), EPA is expressly authorized (and in fact required) to "revise" those categories of sources subject to standards of performance under section 111.[102] Pursuant to this authority, and as described in EPA's 2012 proposed new source performance standards, EPA has already repeatedly revised its source categories for electric utility generating units:

> EPA listed electric utility steam generating boilers . . . and initially regulated them in subpart D of its regulations under CAA section 111. Subsequent regulation of

[101] 79 Fed. Reg. at 34855.
[102] 42 U.S.C. § 7411(b)(1)(A).

> utility boilers has been under subpart Da. The EPA listed stationary combustion turbine engines and initially regulated them under subpart GG. . . . In 2005, the EPA proposed subpart KKKK as a replacement for subpart GG and specifically covered the entire combined cycle facility under subpart KKKK such that only a single set of requirements would apply. In that same year, the EPA proposed to include Integrated Gasification Combined Cycle (IGCC) facilities under the applicability of subpart Da.[103]

If EPA can revise, combine, or otherwise redistribute sources previously subject to different section 111(b) source categories, then EPA has similar authority to combine source categories for purposes of existing source regulation. Moreover, such revision or combination of source categories is particularly appropriate where, as here, both source categories at issue serve the same basic function: to supply power to the grid from the combustion of fossil fuels. Against this backdrop, promulgation of emission guidelines for *all* existing fossil fuel-fired EGUs under a single combined source category is both consistent with EPA's prior practice and permissible under the statute.

F. Emission Reduction Measures Within the Fossil Fuel-Fired EGU Source Categories Are Adequately Demonstrated.

States plainly have the ability to develop plans to achieve emission reductions and take advantage of the many benefits of gas-fired generation, and sources in turn are capable of achieving compliance. A strategy to reduce emissions and take advantage of clean-burning natural gas generation resources throughout the source category also promotes beneficial environmental and energy impacts. For example, NGCC utilization carries the important environmental co-benefit of reducing emissions of conventional pollutants, in addition to reducing CO_2 emissions.[104] Moreover, expanding utilization of domestically produced natural gas supplies promotes fuel diversity and energy independence. Since emission reduction measures within the regulated source categories have already been undertaken by sources covered by the proposed rule, they may be considered to be adequately demonstrated.

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[103] 77 Fed. Reg. 22392, 22397 (Apr. 13, 2012).

[104] *See, e.g.*, 79 Fed. Reg, at 34,841 (discussing co-benefits of reducing exposure to SO2, NOx, and various hazardous air pollutants, among other positive effects). EPA has estimated reductions in ambient particulate matter and ozone will result in human health benefits, although it has not characterized the level of benefit that would inure to increased natural gas-fired generation versus other compliance strategies contemplated by the proposed rule. *See, e.g.*, RIA at 4-17.

V. Any Early Action Alternative Approach Must Equally Credit Measures Based on Natural Gas Use.

In both the proposed rule and NODA, EPA solicits comments on potential alternative approaches under which actions taken prior to the state plan performance period may count toward a state's achievement of proposed emission targets.[105] A variety of alternative approaches are considered, including: an approach in which states could obtain early action credit toward achieving emission targets based on reductions prior to 2020; and an approach in which states could undertake early implementation of state emission targets.[106] To the extent that the final rule includes any such early action option, it is essential that early action crediting be uniformly available irrespective of the type or types of measures for which a state may seek credit. In particular, emission reduction measures based on utilization of natural gas must be eligible for any early action crediting on equal terms with other potential emission reduction measures. Dictating *how* early emission reductions must be achieved would unnecessarily limit the incentive to take advantage of those measures that may carry the greatest immediate benefits. Moreover, if early action credits excluded certain types of measures, the rule would create arbitrary disparities on the basis of what sorts of early action are feasible or most prudent in each state, rendering the proposed emission targets more difficult or costly to achieve in some states than others.

VI. Conclusion

ANGA appreciates the opportunity to submit these comments on the proposed section 111(d) rule for EGUs. ANGA strongly supports the Agency's findings that natural gas is abundant and available throughout the United States and further supports the conclusion that NGCC units are technically capable of running at or above 70 percent capacity. ANGA also supports EPA's proposed rate-based approach to its emission guidelines and believes retaining the rate-based form of the standard is appropriate and consistent with the purpose of 111(d), as well as being advantageous from an economic and environmental standpoint. Before finalizing its proposal, however, EPA must revise its BSER determination to reflect the requirement that any determination of BSER must be based on what can be implemented at and achieved by covered sources. Building Blocks 3 and 4 of EPA's proposed BSER determination run afoul of

[105] *See* 79 Fed. Reg. at 34,918-19; 79 Fed. Reg. at 65,545-46.
[106] 79 Fed. Reg. at 64,545-46.

this requirement and are further incapable of being implemented by the Agency. We also caution the Agency to ensure that claimed energy efficiency savings are real and verifiable. Finally, and in addition to other concerns addressed herein, we also caution the EPA to continue to exclude new sources of emissions from its BSER determination and to make clear that emissions from such sources cannot be required to be included in state compliance plans.

If you have any questions, please contact Jason Smith at jsmith@anga.us, 202-715-1713, or Amy Farrell at afarrell@anga.us, 202-789-2642.

Sincerely,

Martin J. Durbin
President and CEO

Appendix A

Proposed U.S. Natural Gas Pipeline Projects, 2015-2018

Source: Energy Information Administration, Released: October 1, 2014. Available at: http://www.eia.gov/naturalgas/data.cfm

Project Name	Pipeline Operator Name	Project Type	Status	Year In Service Date	State(s)	Region(s)	Additional Capacity (MMcf/d)	Pipeline Type	Authority	Docket Number
Continent to Coast Expansion Project	Portland Natural Gas Transmission System	Expansion	Announced	2016	CN,ME	Canada,Northeast	132	Interstate	FERC	
West Leg 2014 Expansion	Northern Natural Gas	Expansion	Construction	2014	NE	Central	88	Interstate	FERC	CP13-528
Cherokee Natural Gas Pipeline Project	XcelEnergy	Lateral	Approved	2014	CO	Central	189	Intrastate	State	na
Magnum Gas Storage Link	Magnum Gas Storage LLC	Lateral	Construction	2014	UT	Central		Interstate	FERC	CP10-22
Lucerne pipeline	DCP Midstream	New Pipeline	Construction	2014	CO	Central	230	Interstate	FERC	CP13-509
ND to MN	MDU Resources Group	New Pipeline	Announced	2016	ND,MN	Central,Midwest	400	Interstate	FERC	
Wisconsin 2015 Expansion Project	ANR Pipeline	Expansion	Announced	2015	IL	Midwest	-	Interstate	na	na
Valley Power plant lateral	We Energies	Lateral	Approved	2014	WI	Midwest		Intrastate	State	na
Dakota Pipeline	WBI Energy, In	New Pipeline	Announced	2017	ND,MN	Midwest	400		FERC	

Project Name	Pipeline Operator Name	Project Type	Status	Year In Service Date	State(s)	Region(s)	Additional Capacity (MMcf/d)	Pipeline Type	Authority	Docket Number
WBI Energy Wind Ridge Pipeline	Wind Ridge Pipeline	New Pipeline	Announced	2016	ND	Midwest			na	na
NEXUS Gas Transmission	Spectra Energy	New Pipeline	Announced	2016	OH,MI,CN	Midwest,Canada	2,000	interstate	FERC	
Ohio Pipeline Energy Network	Texas Eastern Transmission	Reversal	Approved	2015	OH,LA	Midwest,Southwest	550	Interstate	FERC	CP14-68
Gulf Coast Market Expansion Project	Natural Gas Pipeline Company of America	Reversal	Announced	2016	IL,AR,TX	Midwest,Southwest	750		FERC	na
Upstate Pipeline Project	Millennium Pipeline Co	Expansion	Announced	2016	NY	Northeast	-	interstate	FERC	na
Connecticut Expansion Project	Tennessee Gas Pipeline	Expansion	Announced	2016	MA	Northeast	72	Interstate	FERC	na
Atlantic Bridge project	Algonquin Gas Transmission	Expansion	Announced	2017	NJ,NY,CT,RI,MA	Northeast	100	Interstate	FERC	na
Northeast Connector	Transcontinental Gas Pipeline	Expansion	Construction	2014	PA	Northeast	100	Interstate	FERC	CP13-132
Northern Access 2015 Project	National Fuel Gas Supply Corp	Expansion	Filed	2015	PA,NY	Northeast	140		FERC	CP14-100
Mid-Atlantic Connector Expansion	Transcontinental Gas Pipeline	Expansion	Construction	2014	VA	Northeast	142	Interstate	FERC	CP11-31
Line N West Side Expansion and Modernization Project	NiSource Gas Transmission & Storage	Expansion	Filed	2015	PA	Northeast	175		FERC	CP14-70

Project Name	Pipeline Operator Name	Project Type	Status	Year In Service Date	State(s)	Region(s)	Additional Capacity (MMcf/d)	Pipeline Type	Authority	Docket Number
Garden State Expansion	Transcontinental Gas	Expansion	Announced	2016	NJ	Northeast	180		FERC	na
Natrium to Market Project	Dominion Transmission Inc	Expansion	Construction	2014	VA,PA	Northeast	185		FERC	CP13-13
Rose Lake Expansion Project	Tennessee Gas Pipeline	Expansion	Construction	2014	PA	Northeast	230		FERC	CP13-3
Virginia Southside Expansion	Transcontinental Gas Pipeline	Expansion	Approved	2015	VA	Northeast	270	Interstate	FERC	CP13-30
East Side Expansion Project	NiSource Gas Transmission & Storage	Expansion	Filed	2015	PA	Northeast	310	Interstate	FERC	CP14-17
Algonquin Incremental Market (AIM)	Algonquin Gas Transmission	Expansion	Announced	2016	NJ,NY,CT,RI,MA	Northeast	342	Interstate	FERC	PF13-16
Northern Access 2016 Project	National Fuel Gas Supply Corp	Expansion	Pre-filed	2016	PA,NY	Northeast	350		FERC	PF14-18
Leidy Southeast Expansion	Transcontinental Gas Pipeline	Expansion	Applied	2015	PA	Northeast	525	Interstate	FERC	CP13-551
Broad Run Flexibility Project	Tennessee Gas Pipeline	Expansion	Announced	2015	WV	Northeast	590		FERC	na
TETCO TEAM 2014 Expansion	Texas Eastern Transmission	Expansion	Approved	2014	PA	Northeast	600	Interstate	FERC	CP13-84
WRIGHT INTERCONNECT PROJECT	Iroquois gas pipeline	Expansion	Announced	2015	NY	Northeast	650	compressor	FERC	na

Project Name	Pipeline Operator Name	Project Type	Status	Year In Service Date	State(s)	Region(s)	Additional Capacity (MMcf/d)	Pipeline Type	Authority	Docket Number
Ohio Valley Connector	Equitrans	Expansion	Pre-filed	2016	WV,OH	Northeast	900		FERC	PF14-13
Access Northeast	Algonquin Gas Transmission	Expansion	Announced	2018	NY,CT,MA	Northeast	1,000		FERC	na
Diamond East Project	Transcontinental Interstate Pipeline	Expansion	Announced	2018	PA,NY	Northeast	1,000		FERC	na
Utica Ohio River Project	Regency Energy Partners /American Energy	Expansion	Announced	2015	OH	Northeast	2,100		FERC	na
Mountaineer XPress Pipeline Project (MXP)	Columbia Gas Transmission	Expansion	Announced	2017	WV	Northeast	2,500		FERC	na
Line MB extension project	Columbia Gas Transmission	Expansion	Construction	2014	MD	Northeast		Interstate	FERC	CP13-8
Tuscarora Lateral Project	Empire Pipeline	Lateral	Filed	2015	NY	Northeast	54	Interstate	FERC	CP14-112
White Oak Lateral Project	Eastern Shore Natural Gas	Lateral	Construction	2014	DE	Northeast	55		FERC	CP13-498
Salem Lateral Project	Algonquin Gas Transmission	Lateral	Applied	2015	MA	Northeast	115		FERC	CP14-522
Rock Springs Expansion	Transcontinental Gas Pipelne	Lateral	Pre-filed	2016	NJ	Northeast	192		FERC	PF14-
Woodbridge lateral	Transcontinental Gas Pipe Line Co	Lateral	Approved	2015	NJ	Northeast	264		FERC	CP14-18
Texas Eastern Natrium Lateral Project	Texas Eastern Transmission	Lateral	Announced	2014	WV	Northeast	400	Interstate	na	na

Project Name	Pipeline Operator Name	Project Type	Status	Year In Service Date	State(s)	Region(s)	Additional Capacity (MMcf/d)	Pipeline Type	Authority	Docket Number
New market project	Dominion Transmission	New Pipeline	Filed	2016	PA	Northeast	112		FERC	CP14-498
Clarington Project	Dominion Transmission	New Pipeline	Filed	2016	WV	Northeast	250		FERC	CP14-496
Transco Rockaway Delivery Project	Transcontinental Gas Pipeline	New Pipeline	Construction	2014	NY	Northeast	647	Interstate	FERC	CP13-36
Constitution Pipeline	Constitution Pipeline Co	New Pipeline	Filed	2015	PA,NY	Northeast	650	Interstate	FERC	CP13-499
PennEast Pipeline Co	PennEast Pipeline Co	New Pipeline	Announced	2017	PA	Northeast	1,000		FERC	na
Leach XPress project	Columbia Pipeline	New Pipeline	Announced	2017	OH,WV	Northeast	1,500		FERC	na
Northeast Energy Direct	Tennessee Gas Pipeline	New Pipeline	Pre-file	2018	PA,NY,MA	Northeast	2,200		FERC	PF14-22
Lebanon lateral project phase 2	ANR Pipeline	reversal	Announced	2015	IN,OH	Northeast	290		FERC	na
Lebanon lateral project	ANR Pipeline	reversal	Announced	2014	OH	Northeast	350	Interstate	na	na
Lebanon lateral project phase 3	ANR Pipeline	reversal	Announced	2017	OH	Northeast			FERC	na
Niagara Expansion Project	Tennessee Gas Pipeline	Expansion	Filed	2015	NY,CN	Northeast,Canada	158		FERC	CP14-88
Rover Pipeline Project	ET Rover Pipeline	New Pipeline	Pre-filed	2017	PA,WV,OH,MI,CN	Northeast,Canada	3,250		FERC	PF14-14

Project Name	Pipeline Operator Name	Project Type	Status	Year In Service Date	State(s)	Region(s)	Additional Capacity (MMcf/d)	Pipeline Type	Authority	Docket Number
South to North project	Iroquois gas pipeline	Reversal	Announced	2016	NY,CN	Northeast,Canada	300		FERC	
Gulf Markets Expansion (bi-directional)	Texas Eastern Transmission co	Reversal	Announced	2017	PA,OH,WV,KY,TX	Northeast,Central	350		FERC	na
Atlantic Sunrise Project (bi-directional)	Transcontinental Gas Pipeline	Reversal	Pre-filed	2017	PA,VA,NC,SC,GA,AL	Northeast,Central	1,700		FERC	PF14-8
Clarington West Project	Rockies Express Pipeline	Reversal	Announced	2016	OH,WY	Northeast,Central	2,500		FERC	
Access South Project	Texas Eastern Transmission co	Reversal	Announced	2017	PA,WV,KY,TN,AL,MS	Northeast,Midwest	320		FERC	na
Uniontown to Gas City Expansion Project (U2GC) (bi-directional)	Texas Eastern Transmission co	Reversal	Approved	2015	PA,OH,IN	Northeast,Midwest	425		FERC	CP14-104
Ohio-Louisiana Access project	Texas Gas Transmission	Reversal	Applied	2016	OH,IN,KY,TN,MS,LA	Northeast,Midwest			FERC	CP14-553
Western Marcellus Pipeline Project	Transcontinental Interstate Pipeline	Expansion	Announced	2018	OH,WV,VA	Northeast,Norhteast	2,000		FERC	na
Atlantic Coast Pipeline	Atlantic Coast Pipeline	New Pipeline	Announced	2018	WV,VA,NC	Northeast,Southeast	1,500		FERC	
Mountain Valley Pipeline	Mountain Valley Pipeline	New Pipeline	Announced	2018	WV,VA,NC	Northeast,Southeast	2,000		FERC	na
Adair Southwest Project	Texas Eastern Transmission co	Reversal	Announced	2017	PA,WV,OH,KY	Northeast,Southeast	200		FERC	na

Project Name	Pipeline Operator Name	Project Type	Status	Year In Service Date	State(s)	Region(s)	Additional Capacity (MMcf/d)	Pipeline Type	Authority	Docket Number
Utica Backhaul Transportation	Tennessee Gas Pipeline	Reversal	Announced	2015	PA,TN	Northeast,Southeast	352	Interstate	FERC	
West Side Expansion Project (Smithfield III)	Columbia Gas Transmission	Reversal	Completed	2014	PA,WV,KY	Northeast,Southeast	444		FERC	CP13-477
SEML reversal	ANR Pipeline	reversal	Announced	2015	IN,KY,TN,MS,AR,LA	Northeast,Southwest	1,000		FERC	na
Washington Expansion Project	Northwest Pipeline	Expansion	Pre-filed	2018	WA,OR	Northwest	750	Interstate	FERC	PF12-20
Carty Lateral Project	Gas Transmission Northwest LLC	Lateral	Approved	2015	OR	Northwest	175	Interstate	FERC	CP12-494
Aguirre LNG Pipeline	EcoElectrica	Lateral	Construction	2015	PR	Puerto Rico	186	Interstate	FERC	CP95-35
Elba Express Compressor	Elba Express Pipeline	Expansion	Announced	2015	GA	Southeast	-	Interstate	FERC	na
Broad Run Expansion Project	Tennessee Gas Pipeline	Expansion	Announced	2017	KY	Southeast	200		FERC	na
Mobile Bay South III Expansion Project	Transcontinental Gas Pipeline	Expansion	Approved	2014	AL	Southeast	225	Interstate	FERC	CP13-523
Dalton Expansion Project	Transcontinental Gas Pipeline	Expansion	Announced	2017	AL,GA	Southeast	448	Interstate	FERC	na
Southeast Market Expansion	Gulf South Pipeline	Expansion	Construction	2014	MS,AL	Southeast	511	Interstate	Ferc	CP13-96

Project Name	Pipeline Operator Name	Project Type	Status	Year In Service Date	State(s)	Region(s)	Additional Capacity (MMcf/d)	Pipeline Type	Authority	Docket Number
Hillabee Expansion phase 1	Transcontinental Pipeline	Expansion	Announced	2017	AL	Southeast	818		FERC	na
Gulf Trace Expansion Project	Transcontinental Pipeline	Expansion	Announced	2017	LA	Southeast	1,200		FERC	na
Interconnect Pipeline Project	Clarksville Gas & Water Department	Lateral	Pre-filed	2015	KY,TN	Southeast	52	interstate	FERC	PF13-17
Kingsport Expansion Project	East Tennessee Natural Gas	Lateral	Construction	2015	TN	Southeast	61	Interstate	FERC	CP13-534
White Plains Gas Storage Laterals	Orbit Gas Storage, Inc.	Lateral	Approved	2015	KY	Southeast	100	Interstate	FERC	CP08-409
MoBay Storage Line	MoBay Storage Hub	Lateral	Approved	2016	AL	Southeast	1,000	Interstate	FERC	CP06-398
Riviera Beach plant link	Florida Power & Light Co	lateral	Announced	2014	FL	Southeast		intrastate	State	na
Interconnect Pipeline Project	Clarksville Gas & Water Department	New Pipeline	Pre-filed	2015	KY,TN	Southeast	52		FERC	PF13-17
Florida Southeast Connection	NextEra Energy	New Pipeline	Announced	2017	FL	southeast	600	interstate	FERC	
Renaissance Gas Transmission Project	Spectra Energy	New Pipeline	Announced	2016	AL,TN,GA	Southeast	1,000	Interstate	FERC	na
Port Dolphin LNG Pipeline	Port Dolphin Pipeline LP	New Pipeline	Approved	2015	FL	Southeast	1,200	Interstate	FERC/Coast Guard	CP07-191

Project Name	Pipeline Operator Name	Project Type	Status	Year In Service Date	State(s)	Region(s)	Additional Capacity (MMcf/d)	Pipeline Type	Authority	Docket Number
Sabal Trail Project	Spectra Energy Corp/NextEra Energy, Inc	New Pipeline	Announced	2017	AL,GA,FL	Southeast	1,000	interstate	FERC	
Rayne XPress Project	Columbia Gulf Transmission	Reversal	Announced	2016	KY,TN,MS,LA	Southeast,Southwest			FERC	na
Rich Eagle Ford Mainline Expansion III	Energy Transfer Partners LP	Expansion	Announced	2014	TX	Southwest	200		State	na
Creole Trail Expansion Project	Cheniere Creole Trail Pipeline	Expansion	Approved	2016	LA	Southwest	1,530	Interstate	FERC	CP12-351-
Eagle Ford Midstream Expansion	NET Midstream LLC	Expansion	Completed	2013	TX	Southwest		Intrastate	State	na
2015 Elko Area Expansion Project	Paiute Pipeline	Lateral	Pre-filed	2015	NV	Southwest	22		FERC	PF14-4
Panda Power Lateral Project	Gulf Crossing	Lateral	Construction	2014	TX	Southwest	125		FERC	CP13-64
Great Basin Project Scope	Great Basin Energy Development	Lateral	Announced	2016	NV,CA	Southwest	250	Interstate	FERC	na
Perryville Storage Laterals	Perryville Gas Storage LLC	Lateral	Construction	2015	LA	Southwest	600	Interstate	FERC	CP09-418
Tricor Ten Section Hub Natural Gas storage pipeline	Tricor Ten Section Hub LLC	Lateral	Construction	2014	CA	Southwest	973	Interstate	FERC	CP09-432

Project Name	Pipeline Operator Name	Project Type	Status	Year In Service Date	State(s)	Region(s)	Additional Capacity (MMcf/d)	Pipeline Type	Authority	Docket Number
Edinburg Lateral	Houston Pipe Line	Expansion	Approved	2014	TX,MX	Southwest,Mexico	140		FERC	CP14-13
South Texas Expansion Project	Texas Eastern Transmission	Expansion	Announced	2014	TX,MX	Southwest,Mexico	300	Interstate	FERC	na
Sierrita Pipeline Project	Sierrita Gas Pipeline	Lateral	Construction	2014	AZ,MX	Southwest,Mexico	201	Interstate	FERC	CP13-73/74
Eagle Ford Shale Pipeline System Expansion	NET Mexico Pipeline	New Pipeline	Announced	2014	TX,MX	Southwest,Mexico	2,100	Interstate	FERC	CP13-482
Southeast Supply Header Pipeline	Southeast Supply Header LLC	Expansion	Approved	2015	LA,AL	Southwest,Southeast	45		FERC	14-87
Pacific Connector Gas Pipeline	Northwest/PG&E/Chicago Prtnrs	Lateral	Filed	2017	OR	Western	1,000	Interstate	FERC	CP13-492
Great Basin Energy Project	Great Basin Energy Development	New Pipeline	Announced	2016	NV,CA	Western	250	Intrastate	State	na
Oregon Pipeline	Oregon Pipeline Company, LLC	New Pipeline	Announced	2018	OR	Western	1,250	Interstate	FERC	CP09-7/CP09-6