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United States Environmental Protection Agency
Docket Center
Mailcode 28221T
1200 Pennsylvania Ave. NW
Washington, DC 20460

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RE: Comments on Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (EPA–HQ–OAR–2013–0602).

The American Clean Skies Foundation (ACSF) is a Washington D.C.-based non-profit organization founded to advance America's energy security and promote a cleaner environment through the expanded use of natural gas, renewable energy, and energy efficiency. ACSF appreciates the opportunity to submit these comments on EPA's proposed rule "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (hereafter, the "Proposed Rule" or "Clean Power Plan")[1] and the accompanying supplemental Notice of Data Availability (NODA).[2]

Executive Summary

The agency's Clean Power Plan represents a historic and urgently needed measure to systematically reduce harmful greenhouse gas (GHG) emissions from the nation's existing electric generating units (EGUs).[3] ACSF supports the basic structure of the Plan because it provides a flexible set of workable guidelines for state and regional implementation plans that can deliver substantial emission reductions from fossil fuel-fired EGUs, particularly coal-fired power plants.

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[1] The Proposed Rule was published at 79 Fed. Reg. 34,830 (June 18, 2014).

[2] The NODA was published at 79 Fed. Reg. 64,543 (October 30, 2014).

[3] The urgency of mitigating the GHG buildup in the atmosphere has been highlighted by numerous recent reports including the Intergovernmental Panel on Climate Change's *Fifth Assessment Report* (http://www.ipcc.ch/report/ar5/) and the *2014 National Climate Assessment* (http://nca2014.globalchange.gov/).

In ACSF's view, however, the EPA may have underestimated the emission reductions that can be achieved through increased natural gas use in the power sector, including through (1) "inside the fence" ("on-site") emission reductions and (2) re-dispatch strategies. A Clean Power Plan that contemplates a more robust use of natural gas would enhance the options available to state officials and strengthen the Plan's legal merits by reducing the need to rely upon "outside the fence" or "off-site" actions taken by parties that have not heretofore been directly regulated by the Clean Air Act (e.g. non-sources that do not directly emit GHGs, but could reduce electricity consumption through greater efficiency).

Moreover, the expanded dispatch of natural gas combined cycle units (NGCC) can provide immediate, substantial emission reductions, as the EPA and other observers have recognized.[4] Thus, in addition to adopting a Clean Power Plan that appropriately weights the contribution that can be made by gas-fired generation, it is essential that EPA work pro-actively with federal and state electric power regulators to ensure that adequate gas pipeline capacity is available to meet the need for the expanded dispatch of NGCC and other gas-fired EGUs.

Greater reliance on gas-fired power under the Proposed Rule will also place a heightened responsibility on natural gas producers and pipeline operators to mitigate fugitive emissions of methane across the supply chain so that the full fuel cycle GHG reductions from fuel switching in the power sector (e.g. gas for coal) is as large as possible. There is significant evidence that American industry can meet the challenge,[5] but ongoing attention will be needed by the private and public sector alike to ensure that the GHG mitigation potential of gas-fired generation is fully realized.

ACSF also believes that EPA should provide states the *option* of meeting GHG reduction goals through the expanded use of renewable energy (RE) and end-use energy efficiency. In addition, a state's potential to use RE should take into account regional options as well as the potential of new regulatory initiatives (e.g. green tariffs, shared renewable programs, direct access measures) to spur greater deployment of RE.

The body of ACSF's comments provides more details regarding the following points:

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[4] The much lower GHG footprint of gas-fired generation (as compared to coal-based power) has been confirmed by almost all independent observers despite concerns regarding methane leakage (sometimes termed fugitive emissions) associated with shale gas production. *See* Ramon A. Alvarez, Stephen W. Pacala, James J. Winebrake, William L. Chameides and Steven P. Hamburg, *Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure*, Proceedings of Natl. Academy of Sci. of U.S. (Feb. 2012), available at http://www.pnas.org/content/early/2012/04/02/1202407109.

[5] *See e.g*. The University of Texas at Austin, *Unprecedented Measurements Provide Better Understanding of Methane Emissions During Natural Gas Production* (September 16, 2013), available at http://www.utexas.edu/news/2013/09/16/understanding-methane-emissions/. *See also* the ongoing work of the Environmental Defense Fund on methane leakage at http://www.edf.org/methaneleakage.

1. The scope for natural gas-fired generation to achieve significant "inside the fence" emission reductions.
    - Including more natural gas inside the fence measures would maximize the likelihood that meaningful emission reductions withstand judicial scrutiny of this rulemaking.
    - BSER must include new NGCC at existing power plant locations. As detailed in Attachment A, over 20 GW of new NGCC plants have been proposed (or are already sited) at the location of de-commissioned coal plants and the EPA should take this trend into account.
    - EPA should more fully assess coal-to-gas boiler conversions given the growing number of such conversions by the power industry. See e.g. Attachment B detailing over 12 GW of conversions.

2. Dispatch switches from coal to gas can be taken exclusively by regulated sources (EGUs) and provide a key, near-term source of emission reductions.
    - ACSF supports EPA's approach regarding the increased dispatch of *existing* NGCC.
    - As noted in the NODA, EPA also should carefully consider the expanded role of *new* NGCC, which can promote environmentally-friendly dispatch changes.

3. EPA should work proactively with electric power regulators to ensure that adequate pipeline capacity is available for the expanded dispatch of gas-fired generation.

4. EPA should encourage more flexible market-based approaches to supplying renewable power. Greater reliance on renewable (zero carbon) generation can also reduce the emission reduction burden on fossil fuel power plants.

Discussion

1. ***The Proposed Rule overlooks the ability of natural gas-fired generation to achieve significant "inside the fence" emission reductions.***

    a. ***Including more natural gas inside the fence measures would maximize the likelihood that meaningful emission reductions withstand judicial scrutiny of this rulemaking.***

In this rulemaking, EPA is proposing "emission guidelines for states to follow in developing plans" to reduce GHG emissions "from existing fossil fuel-fired electric generating units (EGUs)" under CAA section 111(d).[6] Under these provisions, state plans must establish standards of performance that reflect the ''best system of emission reduction'' (BSER) that

[6] 79 Fed. Reg. 34,832.

"taking into account the cost of achieving such reduction and any non-air quality health and environmental impacts and energy requirements, the Administrator determines has been adequately demonstrated."[7] The Proposed Rule includes state-specific goals that reflect EPA's "calculation of the emission limitation that each state can achieve through the application of the BSER."[8]

EPA's proposed BSER is based on four "building blocks": improved operations at EGUs, dispatching lower-emitting NGCC, the increased use of zero-emitting energy (e.g., renewable energy), and end-use energy efficiency.[9] EPA considers this a "portfolio" approach, whereby a state may choose to implement a mix of emission reduction strategies.[10]

ACSF agrees with other key stakeholders that BSER should start with a focus on "inside the fence measures" and measures that can be taken at EGUs.[11] Sources then should be able to *opt* to use outside the fence measures to facilitate compliance such as renewable energy and energy efficiency.

The Clean Air Act "performance source" regulatory provisions focus on "sources" and "source categories"—i.e., measures that are "inside the fence" or otherwise involve regulated entities. "Sources" and "source categories" are legal terms of art, with a long implementing history.[12] A "stationary source" means "any building, structure, facility, or installation which emits or may emit any air pollutant."[13] The Clean Air Act structure, definitions and implementing history all indicate, when setting BSER limits, the focus is emission reduction measures that are taken by "sources"—not unrelated third parties such as end-use energy efficiency providers.

A more robust inclusion of inside the fence measures by EPA could maximize the chance that an ESPS program with meaningful emission reductions withstands judicial scrutiny. EPA argues that CAA Section 111(d) is "reasonably interpreted to have a more capacious meaning" and encompasses energy efficiency and renewable energy standards that "are reasonably considered to be 'for' affected sources if they would have an effect on affected

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[7] *Id*. at 34,834. For the sake of convenience, these performance standards may be referred to herein as "existing source performance standards" (ESPS).
[8] 79 Fed. Reg. 34,834.
[9] *Id. at* 34,835.
[10] *Id. at* 34,837.
[11] *Id. at* 34,847.
[12] Section 111 was enacted in 1970, and since then EPA has promulgated new source performance standards (NSPS) under Clean Air Act Section 111(b) for dozens of discreet "source categories." *See* EPA's *Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units*, pp. 1-2 (hereafter referred to as "EPA Legal Memorandum").
[13] CAA Section 111(a)(emphasis added).

sources."[14] This novel interpretation of Section 111(d) is likely to attract considerable judicial scrutiny.[15] So too will the EPA's efforts to include outside the fence options as part of a legislatively-based "system of emission reduction" that would extend to actions by unregulated third-party energy efficiency providers.[16]

EPA should at least "hedge its bets" by a fuller consideration of key inside the fence measures that involve natural gas. In view of the foregoing, ACSF believes that EPA should augment building block 2 of the Proposed Rule based on inside the fence natural gas measures so that, if outside the fence measures (such as energy efficiency) be deemed illegal as a basis for BSER, the ESPS can still maintain robust emission reduction targets.[17] For these and other reasons outlined below, ACSF supports the use of replacement NGCC units, boiler conversions and gas co-firing at existing units as key components of BSER given they are on-site and may be undertaken by existing sources.[18]

In ACSF's suggested building block approach, EPA should start with building blocks 1 and 2, which include inside the fence heat rate improvements and NGCC dispatch changes. EPA did just this in separate modeling.[19] Building blocks 1 and 2 can result in 22% emission reductions by 2020, at lower overall program costs than the currently-proposed four building

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[14] 79 Fed. Reg. 34,903.

[15] The recent Supreme Court *UARG v. EPA* case highlights some of the limits of EPA's authority, when the Court reversed portions of a related EPA GHG permitting program. There, the Court noted that when "an agency claims to discover in a long-extant statute an unheralded power" to regulate "a significant portion of the American economy … we typically greet its announcement with a measure of skepticism." 134 S. Ct. 2427, 2444 (2014).

[16] Notably, EPA's regulating existing sources under section 111(d) has been rare. Over the last forty years, under CAA section 111(d), the agency has regulated only a limited number of source categories, such as phosphate fertilizer plants, sulfuric acid plants, primary aluminum plants, kraft pulp plants, and municipal solid waste landfills. EPA Legal Memorandum, p. 9. As to regulating "systems," EPA states that it "has authorized states to allow large municipal waste combustors to average their emission rates and trade NOx emission credits." EPA Legal Memorandum, p. 63. However, this prior EPA action primarily supports trading emission credits among regulated entities and sources (as opposed to unregulated third partied such as energy efficiency providers). By way of precedent for emission trading among EGUs, EPA also authorized an emission trading program for coal-fired EGUs (which included combined-cycle units) under Section 111 in the Clean Air Mercury Rule. *See* 70 Fed. Reg. 28,606 (May 18, 2005), vacated on other grounds by *New Jersey v. EPA,* 517 F.3d 574 (D.C. Cir. 2008).

[17] EPA could also create an option where the increased use of natural gas inside the fence (including new NGCC and boiler conversions) is a separate building block, e.g. a building block "2A." EPA has created a "severability" provision whereby those building blocks that withstand judicial scrutiny should remain, if other building blocks are found invalid. 79 Fed. Reg. 34,892. Allowing for these inside-the-fence natural gas measures to be characterized, in the alternative, as a "separate" building block could allow the measures to remain in place as a basis for BSER should other measures not withstand judicial scrutiny.

[18] This option for BSER is reiterated in Section III.B. of the NODA at 79 Fed. Reg. 64,550.

[19] *See e.g.*, 79 Fed. Reg. 34,932-33.

block approach.[20] These initial two building blocks are also practical, common sense-solutions that are legally defensible. As EPA notes, "One reason for considering a BSER comprising these two building blocks is that it *involves only affected EGUs* and generation from affected EGUs."[21]

In addition, as stressed above, and outlined in the NODA, building block 2 should be augmented by a better assessment of the increased use of inside the fence natural gas, including coal-to-gas boiler conversions and new NGCC, which would generate additional emission reductions. In particular, EPA should more fully consider what types of activities a source can undertake to continue to *generate its product* (electricity), at existing source-controlled sites, including through cost-effective measures involving the use of *cleaner fuels*. To wit: a fuller consideration of natural gas.[22] Indeed, consideration of these inside-the-fence natural gas measures should be considered *mandatory*. The Clean Air Act requires that the ESPS "shall" contain the best system of emission reduction.[23] These natural gas measures are both eminently "adequately demonstrated" and – as further describe below – cost effective as required by CAA 111(a)(1).

Utilities should then be allowed to <u>voluntarily</u> use what are currently building blocks 3 and 4 (renewable energy and energy efficiency) as an optional crediting mechanism – without *basing* BSER on these building blocks 3 and 4. This is consistent with the language and structure

[20] *Id*.
[21] *Id* at 34,878.
[22] Note that considering "clean fuels" is specified under the Prevention of Significant Deterioration (PSD) program, a program that applies to the permitting of major new sources of pollution such as power plants and is analogous in key respects regarding the GHG permitting of EGUs. *See* the PSD provisions at Clean Air Act Section 169(3), which reference "clean fuels." And because the ESPS requirements are based on flexible "systems" of emission reduction (versus case-by-case permitting), the consideration of clean fuels is particularly appropriate.
[23] CAA 111(d).

of CAA 111(d), as well as existing CAA precedent,[24] and precedent set by leading state programs.[25]

b. *BSER must include <u>new NGCC</u> at existing power plant locations*.

The NODA confirms that replacing fossil steam generation with new NGCC EGUs should be considered a key component of BSER,[26] and EPA had already found that deploying newly-constructed NGCC capacity is "clearly feasible."[27] Furthermore, many sources predict new NGCC as a *key source of future generation* and CO_2 reductions in the power sector. ACSF's "Power Switch" analysis shows new NGCC generally to be the "lowest cost" compliance option when considering the substantial number of coal plants that lack conventional pollutant controls.[28]

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[24] EPA's Legal Memorandum notes that "Congress incorporated into Title IV specific incentives to further encourage electric utilities…to reduce their emissions through demand-side energy efficiency and renewable energy: Section 404(f)-(g) provided a special reserve of allowances to be allocated to electric utilities 'for each ton of SO2 emissions avoided by an electric utility … through the use of … energy conservation measures or … renewable energy.'" EPA Legal Memorandum, p. 61. This supports ACSF's approach; allowing crediting for outside-the-fence measures, but focusing BSER on measures such as coal-to-gas fuel switching and emission trading, all measures which involve "inside the fence" actions by regulated EGUs. Other precedent exists as well. *See generally*, <u>Nordhaus</u> R., Gutherz I., ''*Regulation of CO2 Emissions from Existing Power Plants Under § 111(d) of the Clean Air Act: Program Design and Statutory Authority*,'' Environmental Law Reporter, 44: 10366, 10384, 10387-88 (May 2014), for a discussion of CAA precedent including measures for achieving national ambient air quality standards through state implementation plans (SIPs), which are closely analogous to the ESPS regime.

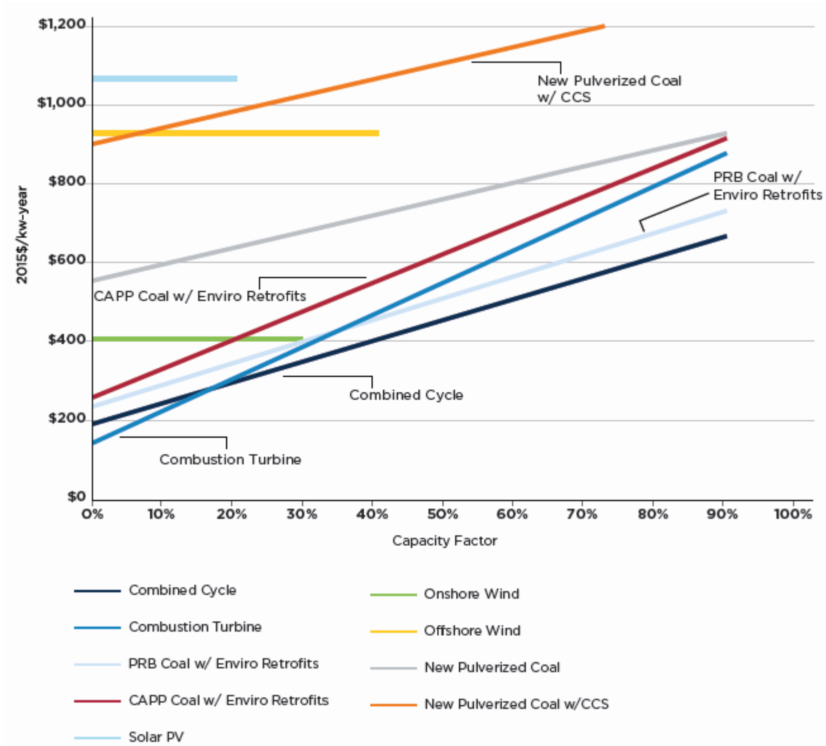
[25] Regarding existing programs that set a precedent for ACSF's recommended approach, EPA notes that "existing state programs, such as RGGI in the northeastern states, do impose the ultimate responsibility on fossil fuel-fired EGUs to achieve the required emission reductions, but are also designed to work either concurrently, or in an integrated fashion, with RE and demand-side EE programs that reduce the cost of meeting those emission limitations." 79 Fed. Reg. 34,901.

[26] NODA at 79 Fed. Reg. 64,550

[27] 79 Fed. Reg. 34,876.

[28] ACSF, *Power Switch: A No Regrets Guide To Expanding Natural Gas-Fired Electricity Generation* (June 2012), p. 19, available at http://www.cleanskies.org. Under this analysis, with a $10 carbon price, NGCC is far cheaper than retrofitting coal plants. *See* Figure 1 in these comments.

Figure 1: Busbar Costs for Different Generation Technologies with $10/ton-CO2 Cost of Carbon



Also, grid operator analysis has shown that adding NGCC to achieve ESPS goals "could be a least-cost solution."[29] Other analyses have found that the "shale boom" makes ESPS "compliance relatively affordable," and NGCC use would significantly increase, with the ESPS incentivizing the construction of new NGCC capacity.[30] Similarly, EIA's 2014 Annual Energy Outlook shows that natural gas constitutes roughly three-fourths of new capacity additions

[29] *See* MISO, *GHG Regulation Impact Analysis – Initial Study Results* (September 17, 2014), p. 10, at https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2014/20140917/20140917%20PAC%20Item%2002%20GHG%20Regulation%20Impact%20Analysis%20-%20Study%20Results.pdf. The Southwest Power Pool has similarly predicted that new combined cycle units would be used to meet ESPS requirements. *See*, SPP, *Responsive Comments Of Southwest Power Pool, Inc*. (September 2014), attachment p. 7, available at https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=935870559. Preliminary results from PJM likewise illustrate the extent to which increased combined cycle dispatch would be utilized under a multitude of various scenarios analyzed. *See* PJM, *EPA's Clean Power Plan Proposal Review of PJM Analyses Preliminary Results* (November 17, 2014), pp. 61-63, available at http://www.pjm.com/~/media/committees-groups/committees/mc/20141117-webinar/20141117-item-03-carbon-rule-analysis-presentation.ashx.

[30] *See* CSIS, *Remaking American Power Preliminary Results* (July 24, 2014), pp. 14-18, available at http://csis.org/files/attachments/140724_RemakingAmericanPower.pdf.

under a variety of scenarios and that "combined-cycle units are favored because of their low fuel prices and relatively moderate capital costs."[31]

Moreover, EPA's own "compliance modeling for this proposal suggests that the construction and operation of new NGCC capacity will be undertaken as method of responding to the proposal's requirements."[32]

Beyond that, a recent announcement from Exelon Generation highlights the potential for an even lower, and perhaps zero emitting, future for natural gas generation. Clearly, natural gas-fired generation can play a significant role in reducing emissions, with future advances potentially enhancing the already significant emission reduction benefits of existing gas-fueled technologies.[33]

Pipeline connection costs do not disqualify new NGCC units as BSER. Some analysis in EPA's Proposed Rule mistakenly suggests that pipeline infrastructure costs would make new NGCC units too costly in many locations and hence disqualify this option as BSER. ACSF believes that any such inference is ill founded. A map compiled by ACSF included as Figure 2 shows just how close most coal-fired power plants are to natural gas infrastructure.

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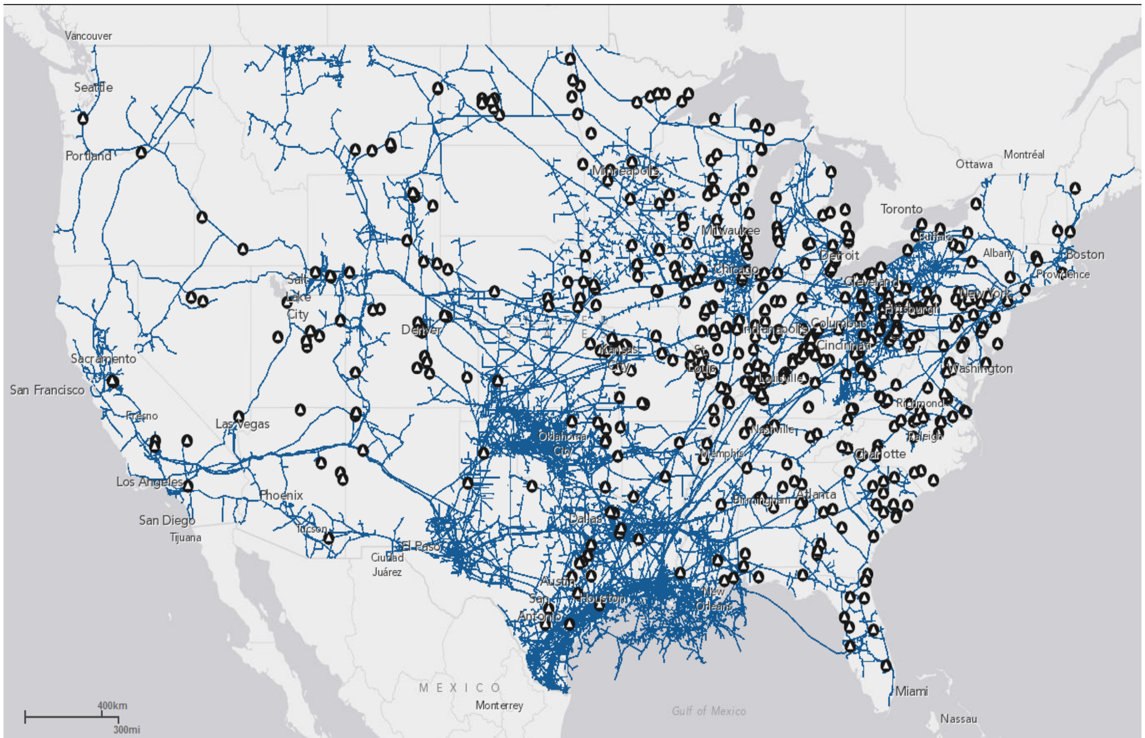
31 EIA, *Annual Energy Outlook 2014*, p. IF-36, available at http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf.

32 79 Fed. Reg. 34,876.

33 *See* "Exelon, CB&I and 8 Rivers Proceed with Clean Energy Demonstration Plant" (October 15, 2014), available at http://www.exeloncorp.com/Newsroom/pr_20141015_power_cleanenergydemoplant.aspx

Figure 2: U.S. Coal Plants and Natural Gas Pipeline Infrastructure[34]



Moreover, EPA itself has assessed the "miles and associated cost of extending pipeline laterals from each [coal] boiler to the interstate natural gas pipeline system."[35] The median miles of pipeline required per boiler is only 27.1 miles, and by definition half of the coal-fired boilers in the U.S. are closer, some significantly closer. Moreover, EPA's median calculated connection cost is only $20 million, an extremely modest cost compared to conventional pollution control retrofits for coal-fired power plants, let alone the cost of carbon capture and storage.[36] Again, the connection costs for half of these coal-fired boilers would be even less than this.

EPA must undertake a more granular analysis of the ability of inside-the-fence new NGCC to arrive at a more legally-defensible BSER. Clearly, in many states, new NGCC is an extremely cost-effective option, and it should be considered on a state-by-state basis, in the same way EPA has proposed considering other building blocks on a state-by-state basis. In many states, combinations of close pipeline access, low natural gas prices and relatively high

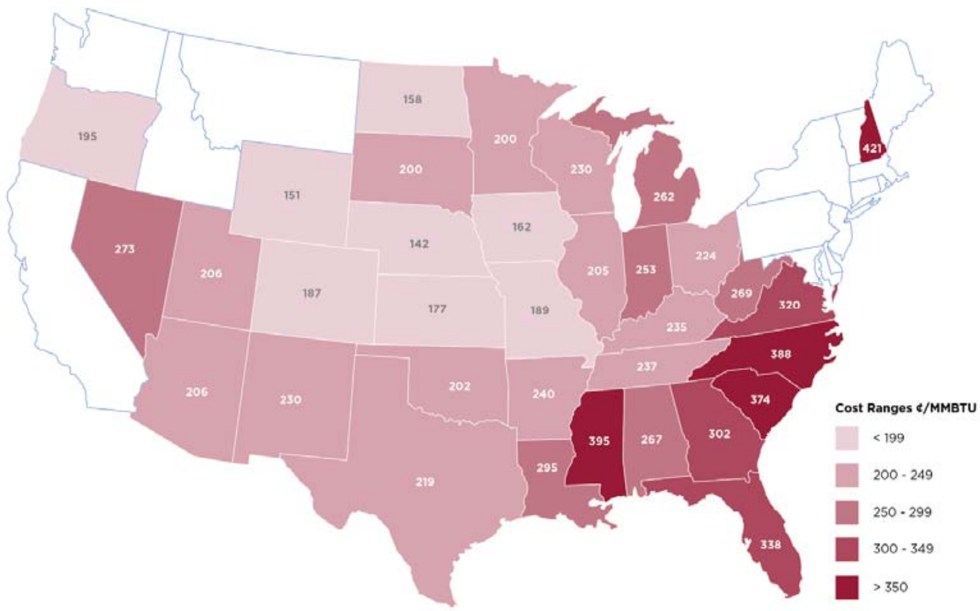
[34] Map compiled by ACSF using EIA U.S. Energy Mapping System, available at http://www.eia.gov/state/maps.cfm.

[35] Chapter 5 in support of EPA's ESPS modelling, pp. 5-34, 5-38, available at http://www.epa.gov/powersectormodeling/docs/v513/Chapter_5.pdf.

[36] *Id*., p. 5-40.

coal prices can make new NGCC a particularly compelling option. For instance, high delivered coal prices to states in the Eastern U.S. are particularly favorable considering recent wholesale natural gas prices.

Figure 3: Average Delivered Coal Costs, 2013[37]



These Eastern states (as with many other states) also have excellent access to natural gas infrastructure.

New NGCC presents a particularly compelling compliance option because new NGCC can make use of existing transmission infrastructure and be built on the existing cites of coal-fired power plants. There is an extensive history of new NGCC being sited at the location of existing coal plants, including at the location of recently retired coal plants.[38] Though not necessarily exhaustive, Attachment A provides a list of NGCC facilities that have been or are being built to replace coal plants on the same site. This list includes more than 25 examples

[37] Data from EIA Form 923, 2013M; available: http://www.eia.gov/electricity/data/eia923/.

[38] *See e.g.*, *Patrick Administration Approves Efficient, Gas-Fired Power Plant to Replace Salem Harbor Station* (October 10, 2013), http://www.mass.gov/eea/pr-2013/gas-salem-power.html.

representing more than 11 GW of retiring coal capacity.[39] Furthermore, new NGCC is a less expensive abatement measure on a CO_2 \$/ton basis than some renewable generation sources.[40]

c. *EPA should more fully assess coal-to-gas boiler conversions given the growing number of such conversions by the power industry*.

EPA completely excludes coal-to-gas boiler conversions from its BSER calculation, though does take comment on the issue.[41] This failure is arbitrary and capricious, and fails to meet the CAA Section 111 mandate to consider the "best" system of emission reductions at EGUs.

Boiler conversions as well as gas co-firing can be widely deployed, and significant precedent demonstrates the technical feasibility and cost effectiveness of these options. The Proposed Rule notes that "Most existing coal-fired steam EGU boilers can be modified to switch to 100 percent gas input or to co-fire gas with coal in any desired proportion."[42] The above analysis by both ACSF and EPA shows just how close most coal-fired power plants are to natural gas pipeline infrastructure (to the extent they are not already connected, as many boilers already use natural gas for startup, some measure of co-firing, and/or generation from combustion turbines co-located on the same site). Furthermore, EPA notes that utilities "see merit in converting some existing coal units to burn 100% gas, and several are currently doing so."[43] Moreover, an ACSF analysis, included as Attachment B, shows the multitude of additional boilers that are currently pursuing conversion from coal to natural gas.

The emission benefits of boiler conversions are significant. EPA calculates that 40% CO_2 reductions can be obtained at those units if run 100% on natural gas.[44] These reductions are above the overall 30% reductions targeted by the ESPS.

EPA must do a more granular assessment of boiler conversions so as to properly characterize them as a BSER option. EPA has too bluntly considered costs for BSER options on an aggregate national basis, when a more granular, state-by-state analysis is necessary. EPA appears to have relied on national average coal and gas prices, when a state and regional comparison – in line with EPA's state-based focus in this rulemaking – shows that boiler conversions can in fact be highly cost effective. For instance, many states in the eastern United

[39] *See* the "New NGCCs at Existing Coal Power Plant Locations" in Attachment A at the end of these comments.
[40] *See* Lazard, *Levelized Cost of Energy Analysis*, Version 8.0 (September 2014), pp. 5, 8, available at http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf.
[41] 79 Fed. Reg. 34,875-76.
[42] *Id*. at 34,875.
[43] ESPS Technical Support Document, *GHG Abatement Measures* (June 10, 2014), p. 6-10.
[44] 79 Fed. Reg. 34,875.

States have comparatively high coal prices and comparatively low gas prices. Moreover, ACSF has identified numerous recently announced boiler conversions, which include 52 units representing more than twelve gigawatts of capacity.[45] A review of data for these facilities shows how EPA has substantially underestimated effective coal prices, thus overstating the cost of boiler conversions and missing the potential for such conversions to contribute to BSER. Furthermore, for existing coal boilers with low capacity factors and needed environmental retrofits if they continue to burn coal, converting to natural gas can make eminent sense, particularly as a bridge to even lower-carbon forms of generation.[46, 47]

2. *Dispatch switches from coal to gas can be taken exclusively by regulated sources (EGUs) and provide a key, near-term source of emission reductions*.

a. *ACSF supports EPA's approach regarding the increased dispatch of existing NGCC*.

ACSF supports EPA's approach regarding the increased dispatch of existing NGCC. The Proposed Rule notes that the average existing utilization rate of 46% at NGCC units could be increased to 70% or more, resulting in CO_2 reductions of over 13% from the combined categories of steam EGUs and NGCC.[48]

Significantly, re-dispatch of <u>existing</u> plants alone can achieve almost <u>half</u> – <u>or more</u> – of the 30% reductions targeted by the ESPS program. Specifically, various studies show EPA's assumption of 13% emission reductions to be not only feasible, but that dispatch changes could bring about emission reductions of 20% or more. For instance, the Massachusetts Institute of Technology has found that NGCC could "displace roughly one-third of U.S. coal generation, reducing CO_2 emissions from the power sector by 20%."[49] A recent NREL study found increased

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[45] *See* the "Comparison of Plants Recently Announcing Coal-to-Gas Conversions" in Attachment B at the end of these comments. *See also* Niven, M., Powell, N., "Coal unit retirements, conversions continue to sweep through power sector" (October 14, 2014)(SNL Financial), available at https://www.snl.com/InteractiveX/Article.aspx?cdid=A-29431641-13357.

[46] For instance, ACSF's table of selected boiler conversion projects (Attachment B) shows that such conversions have occurred at coal plants with 2013 implied capacity factors of 33%.

[47] EPA's fuel switching analysis relied simply on national average coal and gas prices for 2020 from its IPM v5.13 base case model. That model projects U.S. average delivered prices of $5.36 per MMBTU for natural gas and $2.62 per MMBTU for coal. A more granular approach might consider the IPM v5.13 base case projections by region and coal basin; these projections for 2020 average delivered coal prices range from $1.17 to $3.68 per MMBTU. For comparison, 2020 prices of $5.36 for gas but $3.68 for coal would equate to an average cost of avoided CO_2 of approximately $54/tonne for a 100% gas conversion as opposed to $83/tonne. (This avoided cost is based on the generic 500 MW coal unit as analyzed in Chapter 6 of EPA's Technical Support Document.)

[48] 79 Fed. Reg. 34,857-58.

[49] Massachusetts Institute of Technology, *The Future of Natural Gas* (June 6, 2011), p, 86, available at http://mitei.mit.edu/publications/reports-studies/future-natural-gas.

NGCC dispatch could reduce "25% of the sector's total emissions."[50] A report by SNL Financial found that "output from existing units could be increased by as much as 23 percent, 41 percent, and 55 percent in the areas covered by the SPP, MISO and PJM.[51]

ACSF agrees that past regulatory precedent supports the use of dispatch changes as a solution to carbon pollution from a regulatory context. EPA notes that SO_2 and NO_x credit costs have been factored into least-cost economic dispatch, and that CO_2 credit costs have been built into dispatch decisions in RGGI states.[52] EPA explains that "Under both RGGI and California's Global Warming Solutions Act, shifting generation from more carbon-intensive EGUs to less carbon-intensive EGUs is a way to facilitate compliance with regulatory requirements."[53] ACSF agrees that past regulatory precedent shows dispatch changes to be a solution to carbon pollution.

ACSF agrees that past NGCC dispatch increases show the practical feasibility of increasing dispatch. EPA finds that "in April 2012, for the first time ever" gas generation "was approximately equal" to coal generation nationwide.[54] EPA convincingly finds that NGCC generation in 2020 could increase by approximately *50%* from today's levels (roughly the required increase based on a 70% NGCC dispatch target), which reflects a "smaller ramp-up rate in NGCC generation" than the *80*% observed from 2005 to 2012."[55]

IPM modeling confirms the feasibility of a 70% NGCC dispatch target; and states should be required to explore even <u>greater dispatch targets</u> if they seek lowered compliance targets due to the infeasibility of other building blocks.[56] Several states have raised concerns

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Similarly, a recent study from the Clean Air Task Force predicts reductions of 27% by 2020 from 2005 levels, largely through redispatch from existing NGCC resources. See CATF, *<u>An Effective, Affordable Approach to Reducing Carbon Pollution from Existing Fossil-Fueled Power Plants</u>* (February 2014), available at http://catf.us/resources/publications/view/194.

[50] Gelman, R., Logan, J., & Max, D. *Carbon Mitigation from Fuel-Switching in the U.S. Power Sector: State, Regional and National Potentials*. August–September 2014. The Electricity Journal, 27, 63-72.

[51] Piper, S., Gilbert, J., *Prospects for Coal to Gas Switching* (May 1, 2012)(SNL Financial).

[52] 79 Fed. Reg. 34,862.

[53] *Id*. at 34,858. EPA also cites Colorado as one of several examples where "states can design programs that achieve required [GHG emission] reductions while working within existing market mechanisms used to dispatch power." *Id*. at 34,834. For example, in planning for compliance with Colorado's Clean Air, Clean Jobs Plan, Xcel Energy anticipates reducing CO_2 emissions by 35 percent, through increased reliance on natural gas and renewable generation, while limiting annual rate increases to 2 percent annual average over 10 years. *See* http://www.xcelenergy.com/staticfiles/xe/Corporate/Environment/CACJ%20Placemat.pdf.

[54] 79 Fed. Reg. 34,863.

[55] *Id*.

[56] *Id*. at 34,864. See also, the above referenced MIT, CATF, NREL and SNL studies regarding the feasibility of increased dispatch changes.

that – due to state-specific factors – EPA's projections of NGGC dispatch switches may not be feasible. While such state-specific concerns may be warranted in certain circumstances, the consideration of state-specific evidence must not always go in one direction – lowering targets. If a state suggests that BSER should be weakened for a state due to some particular concern with a building block, that state should be required to investigate whether an alternative building block (e.g., the greater dispatch of NGCC) can be used to maintain a robust BSER target for that state.

ACSF agrees that natural gas supplies are adequate at reasonable prices. EPA accurately notes that "There is general agreement that recoverable natural gas resources will be substantially higher for the foreseeable future … exerting downward pressure on natural gas prices."[57] EIA's Annual Energy Outlook for 2014 projects that natural gas production will further increase to 29 TCF.[58] While "NGCC generation growth …calculated in goal setting …would result in increased gas consumption of roughly 3.5 TCF for the electricity sector," this is "less than the projected increase in natural gas production."[59]

Importantly, as EPA notes the "re-dispatch measures in building block 2 are limited to <u>affected sources</u>."[60] By contrast, this is not the case for building blocks 3 and 4 (e.g., energy efficiency measures taken by heretofore unregulated third parties).

b. *EPA should carefully consider the expanded role of new NGCC, which can even further promote environmentally-friendly dispatch changes*.

New NGCC plants – including those located "outside the fence" represent a significant opportunity to reduce GHG emissions. The NODA takes comment on assuming "some minimum level of generation shift from higher-emitting to lower-emitting sources for all states containing some fossil steam generation in the state goals."[61] ACSF considers this a reasonable alternative approach unless a state can affirmatively demonstrate that doing so is not achievable due to extraordinary cost or other issues specific to a state, such as unusual infrastructure limitations. The NODA raises the question regarding whether, for natural gas based BSER requirements, "a phase-in schedule could be developed" based on the need for "additional infrastructure improvements (e.g., natural gas pipeline expansion or transmission improvements)."[62] ACSF considers such an approach acceptable, but if states desire a phase-in

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[57] 79 Fed. Reg. 34,864.
[58] *Id*.
[59] *Id*.
[60] 79 Fed. Reg. 34,889.
[61] 79 Fed. Reg. 64,549.
[62] *Id.* at 64,548.

schedule from otherwise applicable requirements, the need for such a phase-in schedule must be clearly demonstrated.

3. *EPA should work proactively with electric power regulators to ensure that adequate pipeline capacity is available for the expanded dispatch of gas-fired generation*.

ACSF agrees with EPA that natural gas pipeline capacity, with feasible amounts of expansion, can meet the needs of increased natural gas use to reduce carbon pollution. For instance, EPA has found average monthly fleet-wide NGCC utilization rates have reached 65%, showing that the pipeline system can currently support these rates consistent with the increased use of natural gas as BSER "for an extended period."[63] Furthermore, EPA accurately notes that "pipeline and transmission planners have repeatedly demonstrated the ability to methodically relieve bottlenecks and expand capacity."[64] However, EPA should take an even more proactive role to facilitate natural gas infrastructure.

EPA should work pro-actively with entities such as FERC and ISOs on issues such as gas-electric market coordination and the use of firm pipeline capacity by natural gas generators. For instance, market rules may unduly hamper the use of natural gas generation, such as the failure to allow the recovery by natural gas generators of firm pipeline transportation costs.[65]

Also, EPA should indicate that states are allowed, in so far as concerns ESPS compliance programs, to create incentive mechanisms to offset the cost of firm pipeline capacity or other measures to secure natural gas deliverability. These measures could be considered as part of a fuel-neutral pool of credits to address market failures that have impaired the reliable, cost-effective provision of low-carbon electricity.

4. *EPA should encourage more flexible market-based approaches to supplying renewable power to reduce the emission reduction burden on fossil fuel power plants*.

The increased use of renewable energy also can play a large role in reducing electric power sector GHG emissions. To the extent legally permissible, therefore, using renewable energy as a means of achieving performance standards, to facilitate market-based emission

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[63] 79 Fed. Reg. 34,863.
[64] *Id.* at 34,864.
[65] *See e.g.*, PJM, *Problem Statement on PJM Capacity Performance Definition* (August 1, 2014), available at http://pjm.com/~/media/documents/reports/20140801-problem-statement-on-pjm-capacity-performance-definition.ashx. *See also*, Skipping Stone Energy Market Consultants, *Synchronizing Natural Gas & Power Markets* (January 2013), regarding various gas and electric market issues, available at https://www.naesb.org/pdf4/update031413w11.pdf.

reductions, makes good sense. At a minimum, power plant operators should have the option of being able voluntarily to take advantage of increased renewable energy use through a crediting mechanism to meet BSER obligations.

EPA should also consider additional means to promote the use of renewable electricity, including the direct purchase of renewable energy through flexible contract options, shared or community renewable tariff programs and other programs involving the physical delivery of clean electricity. These options, which are aimed in large part at making it practical for corporations and other large electricity users to buy RE (and not just Renewable Energy Certificates (RECs)), could play a significant role in attracting additional RE supply in many states.[66] Moreover, the EPA's express support for such supply-inducing regulatory incentives, would align the agency with the President's recent December 2013 guidance to federal agencies on best practice procurement policy for renewable generation.[67]

Finally, a robust voluntary RE option under the Proposed Rule would leverage the augmented role of gas-fired generation under the Rule. Flexible gas-fired facilities play a key role in providing load-support to variable renewable energy when the wind is not blowing and the sun is not shining.[68]

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[66] *See* ACSF, *Buying Green Power Today: Emerging Options for U.S. Electricity Consumers* (December 2013), available at http://www.cleanskies.org/buyinggreenpower/. *See also* Staple, G., Collier, R., "Fighting for green power - who controls it, who gets it" (San Francisco Chronicle, June 9, 2014), available at http://www.sfgate.com/opinion/openforum/article/Fighting-for-green-power-who-controls-it-who-5540257.php.

[67] *Presidential Memorandum -- Federal Leadership on Energy Management* (December 5, 2013), available at http://www.whitehouse.gov/the-press-office/2013/12/05/presidential-memorandum-federal-leadership-energy-management. The memo states that when agencies cannot install renewable power on-site, they should give priority to the bundled purchase of green electricity rather than simply purchasing stand-alone RECs. In October 2014, the GSA took a significant step toward implementing the Presidential Memorandum when it announced a 10-year power purchase agreement for the total output of a 140 MW wind farm in Illinois. *See* "GSA On Track to Meet Administration's 2020 Renewable Energy Goal with First-of-its-Kind Wind Energy Procurement" (October 23, 2014), available at http://www.gsa.gov/portal/content/199479.

[68] *See e.g.*, the ACSF report *The Business Case for Integrating Clean Energy Resources to Replace Coal* (June 2011), available at http://www.cleanskies.org/category/publications/.

Concluding Remarks

Gas-fired "inside the fence" generation, including NGCC, gas co-firing and coal-to-gas boiler conversions should be considered key components of BSER under the Clean Power Plan. These measures can strengthen the Plan's emission reduction targets. Accordingly, EPA should run alternative compliance scenarios based on these enhanced "inside the fence" measures to ensure that significant emission reduction targets can be met even if "outside the fence" measures are invalidated by the Courts.

Renewable energy can also help significantly to lower greenhouse gas emissions. States should be able to credit renewable energy as a voluntary compliance mechanism. Both natural gas and renewables can provide market-based solutions to reducing greenhouse gas emissions while maintaining grid reliability.

Respectfully submitted,

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Attachment A

New NGCCs at Existing Coal Power Plant Locations

Plant Name	Plant Owner	State	Coal Unit(s) Net Summer Capacity (MW)[1]	New-Build NGCC Capacity (MW)	Year NGCC Operational
Chesterfield (units 1 & 2)	Virginia Electric & Power	VA	120	397	1990 (Unit 7), 1992 (Unit 8)
Grand Tower	Ameren	IL	202	513	2001
Black Dog (units 1 & 2)	Northern States Power	MN	175	270	2002
Urquhart (units 1 & 2)	South Carolina Electric & Gas	SC	128	458	2002
Noblesville	Duke Energy	IN	92	285	2003
H L Culbreath Bayside Power Station / F J Gannon	Tampa Electric	FL	1,046	1,630	2003 (Unit 1), 2004 (Unit 2)
Port Washington Generating Station	We Energies	WI	305	1,090	2005 (Block 2), 2008 (Block 1)
High Bridge	Northern States Power	MN	270	644	2008
Riverside			388	586	2009
Hunlock Power Station	UGI Corporation	PA	44	125	2011
Buck	Duke Energy Carolinas	NC	369	620	2011
Jack McDonough	Georgia Power	GA	502	2,520	2012
John Sevier	Tennessee Valley Authority	TN	352	880	2012
Dan River	Duke Energy Carolinas	NC	276	620	2012
HF Lee			382	1,068	2012
L.V. Sutton Energy Complex			553	625	2013
NRG Energy Center Dover	NRG Energy	DE	16	104	2013
Cane Run	Louisville Gas & Electric	KY	563	640	2015

Cherokee (units 1-3)	Public Service Co of Colorado	CO	365	569	2015
Allen Steam Plant	Tennessee Valley Authority	TN	741	1,000	2016
Salem Harbor	Footprint Power	MA	744	674	2016
Eagle Valley	Indianapolis Power & Light	IN	335	671	2017
Paradise (units 1 & 2)	Tennessee Valley Authority	KY	1,230	1,000	2017
Grand River Energy Center (unit 1)	Grand River Dam Authority	OK	490	495	2017
Crystal River (units 1 & 2)	Duke Energy Florida	FL	869	1,640	2018
Kennecott Power Plant	Rio Tinto Kennecott	UT	175	350	2018
B L England	Rockland Capital	NJ	268	275	Proposed
Black Dog (units 3 & 4)	Northern States Power	MN	232	700	Proposed
Total			**11,232**	**20,449**	

[1]Capacity data from EIA Form 860 for 2012; available: http://www.eia.gov/electricity/data/eia860/

Attachment B

Comparison of Plants Recently Announcing Coal-to-Gas Conversions

Electric Generating Unit	Plant Owner	State	Unit Net Summer Capacity (MW)[1]	2013 Average Delivered Cost of Coal (¢/MMBTU)[2]	2013 Coal Cost Compared to EPA's Base Case 2020 Average[3]	Implied Capacity Factor (2013)[4]	Planned Conversion Year
Bremo Bluff 3	Virginia Electric & Power	VA	71	350	134%	10%	2014
Bremo Bluff 4			156			31%	
Big Cajun II 2	NRG Energy	LA	575			73%	2014
Valley 1	Wisconsin Electric Power	WI	128	371	142%	21%	2014
Valley 2			128			20%	2015
M L Kapp 2	Interstate Power & Light	IA	204	178	68%	43%	2015
Syl Laskin 1	Minnesota Power	MN	47				2015
Syl Laskin 2			50				
Jack Watson 4	Mississippi Power	MS	232	371	142%	52%	2015
Jack Watson 5			474			50%	
Dunkirk 2	NRG Energy	NY	75			8%	2015
Dunkirk 3			185			0%	
Dunkirk 4			185			0%	
W S Lee 3	Duke Energy Carolinas	SC	170			2%	2015
Clinch River 1	Appalachian Power	VA	230	339	129%	19%	2015
Clinch River 2			230			13%	2016
Barry 1	Alabama Power	AL	138	458	175%	3%	2016
Barry 2			137			6%	
Barry 3			249			20%	
E C Gaston 1			254	355	135%	25%	

E C Gaston 2			256			25%	
E C Gaston 3			254			19%	
E C Gaston 4			256			38%	
Greene County 1			254	354	135%	59%	
Greene County 2			243			54%	
Harding Street 5	Indianapolis Power & Light	IN	106	219	84%	0%	2016
Harding Street 6			106			68%	
Harding Street 7			435			16%	
Avon Lake 7	NRG Energy	OH	70			7%	2016
Avon Lake 9			640			51%	
Joliet 6		IL	314			47%	
Joliet 7			518			62%	
Joliet 8			518			62%	
New Castle 3		PA	88			13%	
New Castle 4			87			17%	
New Castle 5			133			14%	
Shawville 1			118			27%	
Shawville 2			121			32%	
Shawville 3			163			41%	
Shawville 4			163			27%	
McMeekin 1	South Carolina Electric & Gas	SC	125	445	170%	31%	2016
McMeekin 2			125			37%	
Big Sandy 1	Kentucky Power	KY	260	318	121%	43%	2016
Yates 6	Georgia Power	GA	352	460	176%	27%	
Yates 7			355			14%	

Cherokee 4	Public Service Co of Colorado	CO	352	257	98%	61%	2017
Edgewater 4	Wisconsin Power & Light	WI	317	235	90%	60%	2018 (unless retired)
Naughton 3	Pacificorp	WY	330	197	75%	91%	2018
Muskogee 4	Oklahoma Gas & Electric	OK	489	199	76%	42%	2019
Muskogee 5			509			53%	
North Omaha 4	Omaha Public Power District	NE	138	146	56%	63%	2023
North Omaha 5			204			52%	
Total Units			**Total Capacity**	**2013 Weighted Average Delivered Cost of Coal**	**As Compared to EPA's Base Case 2020 Average**	**Average Implied Capacity Factor**	
52			12,317	272	104%	33%	

[1]Capacity data from EIA Form 860 for 2012; available: http://www.eia.gov/electricity/data/eia860/
[2]Delivered fuel price data from EIA Form 923, 2013M; available: http://www.eia.gov/electricity/data/eia923/
[3]In its proposed rule, EPA uses an assumed average delivered coal cost of 262 ¢/MMBTU as part of its justification for concluding that coal-to-gas conversions do not qualify as BSER
[4]Unit capacity factors are approximate and assume 100 percent annual availability