Andover Technology Partners 978-683-9599
Consulting to the Air Pollution Control Industry

Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers

C-14-EDF

to:

Environmental Defense Fund
257 Park Avenue South
New York, NY 10010

November 30, 2014

Andover Technology Partners

112 Tucker Farm Road, North Andover, MA 01845

phone: (978) 683-9599; e-mail: staudt@AndoverTechnology.com

Andover Technology Partners
112 Tucker Farm Road, North Andover, MA 01845

Contents

Background

Conversion of existing coal fired boilers to co-fire or to fire 100% natural gas has been performed for a number of reasons, but mainly to reduce emissions of pollutants associated with coal firing.

The purpose of this analysis is to a) demonstrate the technical feasibility of increased use of natural gas at existing coal-fired power plants in the United States; b) illustrate common engineering and logistical issues that arise when power plants undertake such projects, as well as ways in which those issues have been successfully overcome; and c) identify the range of capital and operating costs associated with such projects.

Executive Summary

Conversion from coal to natural gas firing and co-firing of natural gas with coal is not a new phenomenon for coal-fired electric utility boilers, but it is one that has taken on increasing significance in recent years. As demonstrated in this report, experience with conversion of coal to natural gas and also co-firing of natural gas with coal goes back several decades. As such, the technical issues associated with conversions or co-firing are very well understood. Utilization of natural gas offers several benefits: reduction of air emissions and reduction of solid or liquid waste emissions, reduction of parasitic loads, and reduced operating and maintenance costs, just to name a few. On the other side of the ledger, utilization of natural gas will have a slight adverse impact on boiler efficiency, and bears with it an increase in fuel costs which until recently have been deterrents to wider use of natural gas in boilers.

In recent years the economics of converting to natural gas has changed for many facilities. First, natural gas prices fell rapidly a few years ago – reaching a historic low in real (inflation adjusted) cost in 2012 - and although gas prices have risen from that low, natural gas prices have – for most locations in the US - been much more stable than in the past. Second, increased stringency of environmental regulations have increased the cost of burning coal. As such, utilities have become reluctant to expend capital on aging coal units that are less economically viable than in the past. As will be demonstrated in the case studies in this report, avoiding the costs associated with complying with US EPA's Mercury and Air Toxic Standards (MATS) or the Regional Haze Rule (RHR, and the need to install Best Available Retrofit Technology, or BART) have been important motivators in the conversion of some of these facilities to natural gas. There are other factors as well. Some of these facilities have low capacity factors in part due to increased renewable generation and natural gas combined cycle that have displaced coal from base load use to cycling duty. In some of these cases it was more economical to convert the now cycling coal boiler to natural gas than to build new simple cycle combustion turbines for peaking conditions that have similar heat rates as the boiler.

The case studies that form a key element of this report demonstrate that natural gas conversions are being applied in a wide variety of circumstances – throughout several regions of the United States, on boilers of a wide range of sizes from under 100 MW to over 500 MW, on boilers burning a wide range of coals, and on boilers with low as well as high capacity factors. In most cases gas conversion was selected as the lowest cost means of complying with environmental regulations, such as MATS or the RHR. Although in some cases only minor changes were necessary to the natural gas supply infrastructure, in other cases pipelines of over 30 miles in length are being constructed to provide adequate supply. In this respect, depending upon the access to natural gas, the pipeline might be the largest factor in the cost of a natural gas conversion, and it has been a surmountable issue in these circumstances. For the most part, where cost information was available, the cost of the boiler modifications were usually lower than anticipated by EPA in the Technical Support Document for the proposed Clean Power Plan. [1] This is because EPA's cost estimates for natural gas conversion include several elements that are not necessary in many cases.

Table E.1 summarizes data on each of the units examined in the Case Studies in this report. The full year data from 2009 and 2013 are selected as years before and after the changes to the five units where conversions are complete. The majority of the case studies addressed in this report are projects that are currently in progress, and before and after performance information is not available. For those five units where before and after performance information is available, reductions in emission rates (measured in lb/MWh) averaged over 99% for SO_2, 48% for NOx and 38% for CO_2. Although each of the five units where before and after data is available is used as a peaking unit, the best CO_2 emission reductions were experienced on the two units that also have the highest capacity factors. Since most of the projects that are currently in progress recently operated with higher capacity factors than those that are completed and where we have the before and after data, it is likely that reductions in CO_2 emission rates should be on the order of or better than the best of these five units, or about 45%.

With few exceptions, capacity factors were significantly lower in 2013 than in 2009, with the median dropping from 44% to 28% for the Case Study units examined. This is consistent with industry-wide reductions in capacity factor for coal units due to lower natural gas prices. Therefore, although capacity factors dropped for those units where conversions have been completed, this likely would have happened regardless of whether or not a natural gas conversion occurred.

An important and perhaps surprising finding is the fact that some of these gas

[1] US Environmental Protection Agency, "GHG Abatement Measures - Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units Docket ID No. EPA-HQ-OAR-2013-0602", June 10, 2014.

conversions are being performed on units that in 2013 were operated as base loaded power plants as opposed to units that have become marginally economical and limited to peaking or cycling operation. This indicates that conversion to natural gas may not be confined to facilities that are strictly peaking or cycling in nature. It is unclear what the long-term plans are for these converted units. If the converted units are expected to operate at high capacity factors over the long term, future conversion to natural gas combined cycle may be expected because of the lower heat rate of combined cycle power plants. Brunner Island is a project that is unique in that it is a plant that is equipped with a modern wet FGD system. Although this possible co-firing project is in the very early stages of development, it is very notable that a scrubbed facility would consider co-firing natural gas.

Table E.1. Summary of Data on Natural Gas Conversion Units in Case Studies

Completed units in ***bold and shaded***

								Emission rate[2]						% Redn, or year complete			Capacity Factor[3]	
Plant Name	**Unit**	**MW**	**State**	**Firing type**	**Coal**	**heat rate[1]**	**YR on line**	**2009 SO2**	**2009 NOx**	**2009 CO2**	**2013 SO2**	**2013 NOx**	**2013 CO2**	**SO2**	**NOx**	**CO2**	**2009**	**2013**
E C Gaston	1	254	AL	wall	Bit.	9,837	1960	30.3	3.9	2,013	25.9	4.0	2,154		2015		41%	28%
E C Gaston	2	256	AL	wall	Bit.	9,928	1960	31.3	4.0	2,058	26.3	4.1	2,186				49%	27%
E C Gaston	3	254	AL	wall	Bit.	9,843	1961	34.6	5.0	2,307	28.5	4.4	2,337				32%	21%
E C Gaston	4	256	AL	wall	Bit.	9,766	1962	24.9	3.1	1,649	24.0	3.7	1,962				18%	27%
Irvington	4	156	AZ	wall	Bit., Subbit.	10,732	1967	3.0	3.3	1,715	6.3	4.6	2,123		2018		31%	32%
Cherokee	4	352	CO	tang	Bit., Subbit.	10,880	1968	1.8	3.0	1,969	1.6	3.0	2,081		2017		56%	68%
Edge Moor	***3***	***86***	***DE***	***tang***	***Bit.***	***11,954***	***1957***	***5.4***	***1.6***	***2,327***	***0.0***	***0.8***	***1,261***	***100%***	***51%***	***46%***	***36%***	***10%***
Edge Moor	***4***	***174***	***DE***	***tang***	***Bit.***	***11,279***	***1966***	***8.5***	***1.7***	***1,954***	***0.0***	***0.7***	***1,081***	***100%***	***57%***	***45%***	***22%***	***10%***
Yates	Y6BR	352	GA	tang	Bit.	10,492	1974	20.3	2.6	1,988	22.0	2.6	1,966		2015		50%	29%
Yates	Y7BR	355	GA	tang	Bit.	10,487	1974	18.5	2.6	1,938	21.7	2.2	1,970				44%	15%
Harding St.	50	106	IN	tang	Bit	10,541	1958	31.9	2.3	2,130	39.3	2.4	2,051		2016		68%	73%
Harding St.	60	106	IN	tang	Bit.	10,491	1961	32.4	2.4	2,114	37.9	2.4	1,983				69%	72%
Harding St.	70	435	IN	tang	Bit.	10,517	1973	2.2	0.9	1,889	1.3	1.7	2,059				75%	82%
Laskin	1	55	MN	tang	Bit., Subbit.	12,783	1953	4.5	2.3	2,552	1.5	2.0	2,463		2015		58%	56%
Laskin	2	51	MN	tang	Bit., Subbit.	12,875	1953	4.5	2.4	2,563	1.5	2.0	2,456				63%	58%
Meramec	1	119	MO	tang	Bit Subbit	10845	1953	6.2	1.4	2,299	4.7	1.3	2,297		2015		85%	42%
Meramec	2	120	MO	tang	Bit, Subbit	10644	1954	6.1	1.3	2,283	4.9	1.3	2,400				78%	48%
Deepwater	***8***	***73***	***NJ***	***wall***	***Bit.***	***10,331***	***1954***	***9.6***	***3.6***	***1,841***	***0.0***	***2.2***	***1,200***	***100%***	***39%***	***35%***	***13%***	***5%***
Avon Lake	10	96	OH	tang	Bit	12829	1949	2.5	0.4	205	3.0	0.4	205		2016		5%	10%
Avon Lake	12	640	OH	cell	Bit	9823	1970	22.4	3.1	1,812	26.3	2.7	1,796				58%	48%
Muskogee	4	505	OK	tang	PRB	10,593	1977	5.9	3.4	2,200	4.6	3.6	2,171		2018		57%	44%

								Emission rate[2]						% Redn, or year complete			Capacity Factor[3]	
Plant Name	**Unit**	**MW**	**State**	**Firing type**	**Coal**	**heat rate[1]**	**YR on line**	**2009 SO2**	**2009 NOx**	**2009 CO2**	**2013 SO2**	**2013 NOx**	**2013 CO2**	**SO2**	**NOx**	**CO2**	**2009**	**2013**
Muskogee	5	517	OK	tang	PRB	10,652	1978	5.2	3.0	2,016	4.3	2.9	2,023				75%	51%
Brunner Isl	1	312	PA	tang	Bit	10023	1961	18.6	2.6	1,658	3.2	3.5	1,884				88%	58%
Brunner Isl	2	371	PA	tang	Bit	9695	1965	17.9	2.6	1,651	3.6	3.3	1,858		TBD – likely a cofiring project		73%	50%
Brunner Isl	3	744	PA	tang	Bit	9502	1969	6.5	2.8	1,794	3.3	3.3	1,827				72%	55%
New Castle	3	93	PA	wall	Bit	11265	1952	23.6	3.8	2,215	25.1	4.0	2,149				21%	12%
New Castle	4	95	PA	wall	Bit	11028	1958	20.5	3.1	2,011	23.2	3.4	2,007		2016		28%	15%
New Castle	5	132	PA	wall	Bit	10846	1964	24.1	4.5	2,207	26.0	4.7	2,189				23%	15%
Clinch River	1	230	VA	vert	Bit.	10,227	1958	8.8	2.4	2,073	7.8	2.1	2,027				23%	21%
Clinch River	2	230	VA	vert	Bit.	10,179	1958	9.1	2.5	2,022	8.0	2.1	2,050		2015		12%	14%
Clinch River	3	230	VA	vert	Bit.	10,179	1958	8.2	2.0	1,916	8.4	1.8	2,099				46%	14%
Blount St.	***8***	***51***	***WI***	***wall***	***Bit.***	***14,500***	***1957***	***25.8***	***4.2***	***2,479***	***0.0***	***2.3***	***1,794***	***99.9%***	***44.8%***	***27.6%***	***4%***	***2%***
Blount St.	***9***	***50***	***WI***	***wall***	***Bit.***	***14,278***	***1961***	***25.8***	***4.3***	***2,401***	***0.0***	***2.5***	***1,608***	***99.9%***	***41.1%***	***33.0%***	***3%***	***2%***
Valley	1	67	WI	wall	Bit.	14,500	1968	0.8	0.3	205	0.7	0.2	205				42%	31%
Valley	2	67	WI	wall	Bit.	14,500	1968	0.8	0.3	205	0.7	0.2	205		2015/16		44%	30%
Valley	3	67	WI	wall	Bit.	14,500	1969	0.8	0.3	205	0.7	0.2	205				37%	22%
Valley	4	67	WI	wall	Bit.	14,500	1969	0.8	0.3	205	0.7	0.2	205				39%	27%
Naughton	3	330	WY	tang	PRB	10,517	1971	4.3	4.7	2,285	3.5	2.7	2,029		2015		75%	97%
															Median Capacity Factor		***44%***	***28%***

Comments

1. Heat rate in Btu/kWh net from NEEDS v5.13

2. Emissions in lb/MWh of gross generation except Valley and Avon Lake 10, which is in lb/MMBtu

3. Except for Valley Station and Avon Lake unit 10, capacity factor is estimated from reported gross generation and nameplate rating. Because no generation data was reported for Valley Station or Avon Lake unit 10, reported heat input, nameplate MW rating and heat rate were used to estimate capacity factor.

Program Results

Introduction

Natural gas combustion is primarily used in gas turbine applications for power generation with coal being the dominant fuel for fueling utility boilers. Recently, in response to increased availability of natural gas, what appears to be more stable natural gas pricing, and environmental requirements for coal plants, some power plant owners have converted or have announced plans to convert existing coal-fired facilities to natural gas fired facilities. Although in some cases existing coal-fired generating units have been replaced with new natural gas combined cycle units, in some cases existing coal-fired boilers have been or will be retrofit to burn natural gas. Natural gas has the following advantages over coal when used in a boiler:

- Lower NOx emissions and virtually no SO_2, PM, or mercury emissions because natural gas has negligible fuel nitrogen, sulfur or mercury and its combustion produces negligible PM.
- Lower maintenance costs – Due to the absence of slagging or boiler fouling in the furnace, absence of fly ash build up in the ductwork and no need to pulverize and transport solid fuel, maintenance is much less on a gas-fired plant than when firing coal. As a result, there is much less maintenance necessary when firing natural gas and a resulting improvement in unit availability (both planned and unplanned outages). Operating and Maintenance costs could be reduced by as much as 50%.[2]
- Lower parasitic loads – Reduced electricity demand for fuel preparation (coal transport, crushing, pulverizers, etc.) and reduced electrical demand from air pollution control equipment will reduce parasitic loads. This will result in an increase in net output. This has been estimated as about 5 MW on a 250 MW unit, or about 2%.[3]
- Lower CO_2 emissions per unit of heat input and per unit of electricity produced – Natural gas combustion results in roughly 55-60% of the CO_2 emitted per unit of heat input as compared to coal. Natural gas will reduce boiler efficiency which increases heat rate somewhat. After accounting for the beneficial impact on parasitic loads, this will result in about a 2% adverse impact on heat rate[3] – assuming that modifications are not made to recover boiler efficiency. Adjusting for the impact on heat rate, on an electricity-produced basis, natural gas produces

[2] UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013

[3] Brian Reinhart, P.E., Alap Shah, Mark Dittus, Ken Nowling, Bob Slettehaugh, "Paper of the Year: A Case Study on Coal to Natural Gas Fuel Switch", POWER-GEN International 2012.

roughly 56%-61% of the CO_2 compared to coal when used in a boiler.

The principal disadvantages of natural gas as a fuel are:

- Generally higher cost than coal per Btu of heat input.
- Somewhat reduced boiler efficiency due to the increased moisture level in the exhaust gas. This will vary based upon the fuel being used. For example, the impact is greater for bituminous fuel because bituminous fuel has lower moisture content than subbituminous or lignite. The impact is estimated to result in a 200 Btu/kWh (roughly 2%) increase in heat rate when converting to 100% natural gas (coal type was not indicated in the study).[3] Another study showed examined the effects of cofiring natural gas with different coals, with the results in Table 1.

Table 1. Impact of cofiring natural gas with different coals.[4]

Fuel	Heat Rate Difference from Base	CO_2 Reduction
Base – 100% PRB Coal	0	0
100% Bituminous Coal	-1.3%	8%
Bit. Coal/24% NG	+0.9%	9%
PRB Coal/37% NG	+0.15%	17%

- Unlike coal, natural gas is not stockpiled at the plant and is also used for residential and other services – increasing the risk of supply disruption. The risk of having service interrupted during periods where residential demand is high may be addressed with firm, uninterruptible service. However, this will entail purchasing the natural gas at a higher cost.

The following sections of this report will discuss:

- The background on use of natural gas in power generation boilers
- Description of the modifications necessary to co-fire natural gas or to convert to 100% natural gas firing.
- Case studies on coal to gas conversions

[4] ASME Power Plant Efficiency Webinar, September 25, 2014

Background on Use of Natural Gas in Power Generation Boilers

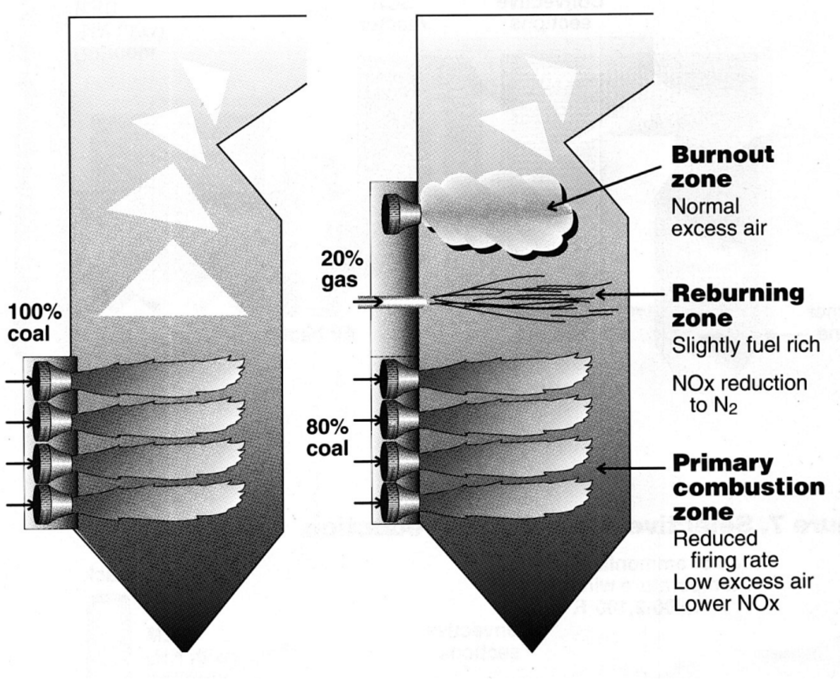
Use of natural gas in coal-fired power generation boilers is not a new phenomenon. For example, conversion of coal-fired boilers to natural gas occurred decades ago in New York City. At the turn of the 19th and 20th century New York City built a network of coal-fired power plants to provide electricity to the railway system because it needed relief from the soot from coal-fueled steam train engines. As natural gas became more available to New York, many of these steam generators that were originally built to burn coal were later converted to 100% natural gas firing because of the desire to reduce the pollutant emissions from these boilers and the associated impact on New York City residents. With time, these boilers have largely been replaced with natural gas combined cycle systems because they are much more efficient in converting the heat of the fuel to electricity than boilers.[5, 6]

Interest in co-firing or converting coal boilers to natural gas increased again in the 1980's and 1990s. Cofiring of natural gas in coal-fired boilers is typically done in many coal-fired boilers upon start-up of the boiler. Boilers start with gas igniters that heat up the furnace and allow ignition of the coal. Interest in cofiring of natural gas at higher loads increased in the 1980's and 1990's with emphasis on reducing NOx emissions from coal-fired boilers. When co-firing, gas may be admitted into the coal burner region, or it may be admitted downstream of the coal burners. One approach for co-firing natural gas that can be used to reduce NOx emissions is natural gas fuel reburn, where natural gas is fired downstream of the primary combustion zone – typically at a point above the coal burners since in most boilers flue gas flow is upward, as shown in Figure 1.

[5] Museum of the City of New York, "Construction of the 74th Street Power Station", http://mcnyblog.org/2012/06/12/construction-of-the-74th-street-power-station/

[6] IEEE, "The Railway Power Stations of New York City", http://www.ieeeghn.org/wiki/index.php/The_Railway_Power_Stations_of_New_York_City

Figure 1. Conventional gas reburning compared to normal firing.



In fact, in the 1980s and 1990s there was a substantial amount of experience gained through the various retrofit uses of natural gas in utility boilers for the primary purpose of NOx reduction. These technologies are distinguished by the amount of natural gas used and where it is introduced into the boiler, and include:

- Seasonal fuel conversion - firing gas as the principal fuel in lieu of coal or oil during the ozone season when NOx emissions were of greatest concern
- Cofiring natural gas with coal at the burner level
- Conventional Gas Reburning, which at the time achieved over 50% NOx reduction through addition of up to about 25% heat input with natural gas downstream of the coal burners.
- Advanced Gas Reburning for higher NOx reduction than possible with conventional gas reburn by combination of Selective Non-Catalytic Reduction (SNCR) with gas reburning
- Fuel Lean Gas Reburn™ (FLGR), which at the time achieved on the order of 35% to 45% NOx reduction with combustion of up to about 10% of heat input with natural gas downstream of the coal burners.
- Amine Enhanced FLGR, which has been demonstrated to achieve 50% to 70% NOx reduction by combination of FLGR with SNCR.

Gas cofiring has also been deployed on boilers that converted from eastern to western fuels. Due to the lower Btu value of the western fuel – which requires that more fuel be fed to the furnace to achieve the same heat input - and limitations on fuel delivery systems, it became necessary on some units to co-fire natural gas to achieve full load.

Table 2 shows the results of a 1998 utility survey of NOx performance from converting from coal to 100% gas on commercial facilities – in some cases demonstrations. These were performed with the primary objective of reducing NOx emissions. Except for the NIPSCO Michigan City unit 12 and the Mitchell unit 4, 50% or more NOx reduction was achieved in every situation. Of course, modern low NOx burner technology for both coal and natural gas fuel would alter the NOx levels from what is shown here, and as shown, most of the units on Table 2 did not have low NOx burners at the time. As a result, advanced combustion controls allowed these units to change back to near 100% operation on coal. Nevertheless, this data demonstrates that gas conversions are not a new phenomenon and can have significant pollutant emission benefits.

Table 3 shows the results of 1990's era gas reburning and fuel lean gas reburning commercial-scale demonstrations and commercial installations. Nearly all of these operated commercially for several years. Several eventually installed low NOx burners to achieve compliance with NOx regulations and could turn off the gas reburn systems. As demonstrated here, these technologies that were used for cofiring natural gas with coal while reducing NOx are not new, but have been available for decades.

Since CO_2 emissions were not the focus of the studies in Tables 2 or 3, the data on CO_2 emissions was not reported; however, it is reasonable to expect that CO_2 emissions would be reduced by roughly 45% for the full gas conversions in Table 2 and by lesser amounts in proportion to the gas use for the reburning or fuel-lean gas reburning results in Table 3.

Table 2. 1990's Era Results from Utility Survey of NOx Performance from Converting Unit from Coal to 100% Gas[7]

Utility	Station	Unit	MW	Demo MW	Yr Online	Type	LNB?	NOx Coal	NOx Gas	% Rem	Com-ments
NIPSCO	Mich Cty	12	540	469	1974	CY	N	2.10	1.20	42.9	(1)
NIPSCO	Mich Cty	12	540	469	1974	CY	N	1.35	1.20	11.1	(2)
PS CO	Cherokee	3	150	158	1962	FF	Y	0.48	0.20	58.3	(3)
PSEG	Mercer	2	326	308	1961	FFW	N	1.80	0.85	52.8	
AZ Elec	Apache	2	195	175	1978	OF	Y	0.63	0.18	71.4	
AZ Elec	Apache	3	195	175	1979	OF	Y	0.59	0.18	69.5	
PSEG	Hudson	2	660	610	1968	OF	N	1.80	0.90	50.0	(4)
IL Pwr	Henepin	1	75	70	1953	TF	N	0.60	0.15	75.0	(5)
IL Pwr	Henepin	1	75	70	1953	TF	OFA	0.35	0.10	71.4	(6)
IL Pwr	Henepin	2	231	214	1959	TF	N	0.70	0.25	64.3	
IL Pwr	Wood R	4	113	93	1954	TF	N	0.70	0.25	64.3	
Com Ed	Fisk	19	374	318	1959	TF	N	0.70	0.28	60.0	
NIPSCO	Mitchell	4	138	125	1956	TF	N	0.40	0.30	25.0	(7)

Comments:

(1) Illinois Basin Coal
(2) PRB/SWY Coal Blend
(3) limited to 80 MW due to gas supply
(4) Unique Slagging Boiler Design
(5) 34% co-fire was 0.40 # NOx/MMBtu
(6) 34% co-fire was 0.20 # NOx/MMBtu
(7) on 70% PRB coa

CY Cyclone firing
FF Front firing
OF Opposed firing
TF Tangential firing
OFA Overfire Air
LNB: Low NOx Burner

As Tables 2 and 3 demonstrate, gas conversions and gas co-firing have been performed on a wide range of boilers, fuel types, and boiler sizes. In addition to these sites, natural gas reburning was deployed commercially at the CP Crane station near Baltimore, and the TVA Allen unit 1 in 1998. These were taken out of service only a few years later. The reason that gas conversions, and gas co-firing such as gas reburning and fuel lean gas reburning are not more widely deployed today is because low NOx coal combustion technology advanced to the point where it was more economical to use low NOx burners to control NOx emissions than to use natural gas. But, as this experience demonstrates, the technology to convert a coal unit to natural gas or co-fire natural gas in a coal unit is well established.

[7] Survey originally performed by Energy Ventures Analysis, "Evaluation of Coal and Oil Boiler Performance and Emissions on Gas - Prepared for Coalition for Gas-Based Environmental Solutions", republished in Staudt, J., Natural Gas NOx Controls, for Gas Research Institute,WP98-35, November 1998

Table 3. 1990's Era Reburning (RB) and Fuel Lean Gas Reburning (FL) Applications, Commercial and Commercial-Scale Demonstrations[8]

Plant	MW	Furnace	Tech-nology	Primary Fuel	Reburn Fuel (%)	Baseline NOx	Outlet NOx	% Red'n
Kodak	60	Cyclone	RB	Coal , 2.25% S	Gas (22)	1.38	0.55*	60
Hennepin	71	Tang, dry	RB	Coal, 2.8 % S	Gas (18)	0.75	0.245	67
Lakeside	33	Cyclone	RB	Coal , 3.6% S	Gas (26)	0.95	0.34	66
Cherokee	158	Wall, dry	RB	Coal, 0.4 % S	Gas (22)	0.75	0.26	64
Greenidge	104	Tang. dry	RB	Coal, 1.8% S	Gas (15)	0.62	0.30	52
Niles	114	Cyclone	RB	Coal	Gas	650 ppm	300 ppm	53
Allen	330	Cyclone	RB	Coal	Gas	NA	NA	NA
Longannet 2	600	Wall, dry	RB	Coal, low S	Gas (~20)	~320 ppm	~160 ppm	50
Mercer	320	Wall, wet	FL	Coal, 0.4 % S	Gas (~7)	1.5		
Riverbend	140	Tang. Dry	FL	Coal, 0.7% S	Gas (~5)	0.45	~0.28	~40%
Joliet	340	Cyclone	FL	Coal	Gas (6)	1.106	0.68	38
Elrama	112	Roof	FL	Coal	Gas (5)	0.59	~0.4	30-35

Natural Gas Conversion or Co-firing as a means of CO_2 reduction

In its Technical Support Document associated with the section 111(d) rule EPA concluded that conversion of coal to natural gas was generally an expensive means to reduce CO_2 emissions when compared to other means.[9] On the other hand, this report will demonstrate that some facilities are, in fact, converting to natural gas. These conversions are motivated by a number of factors that include avoiding capital expenses for other regulations, such as the Mercury and Air Toxic Standards (MATS) and Regional Haze Rule as well as concern over future CO_2 emissions regulations or the need to convert from wet to dry ash handling to mitigate water pollution concerns. Finally, conversion of a boiler to a natural gas peaking unit is typically much less expensive than building a simple-cycle combustion turbine. Unlike combined cycle power plants, simple-cycle turbines do not offer heat rate advantages over a steam cycle. Converted coal plants can become cost effective alternatives to simple-cycle turbines as cycling or peaking units.

[8] Staudt, J., Natural Gas NOx Controls, for Gas Research Institute,WP98-35, November 1998
[9] Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2013-0602, pp 6-9, 6-10

Therefore, when other benefits of gas conversion or cofiring of natural gas are factored into the economics, these projects can be economically viable.

Modifications for Gas Conversion or Cofiring

Modifications to the facility that are necessary to convert a boiler to 100% gas firing or to co-fire natural gas include:

- Those modifications to the boiler that are necessary to burn natural gas and
- Those modifications that are needed to supply adequate amounts of natural gas to the boiler.

Modifications to the boiler for 100% natural gas conversion

Some of these modifications are necessary, and some are beneficial but not essential.

Replacement or modification of burners – This is usually necessary, but may not be if the facility already has burners capable of firing adequate amounts of natural gas. Existing coal burners can be modified by addition of natural gas injection spuds or other modifications. In other cases it may be necessary or even preferable to replace the burners. The decision to replace existing burners will depend upon the condition of the existing burners, their ability to be modified, and the NOx and CO emission limits that may apply. It will also depend upon whether or not the facility wants to maintain the option of burning coal sometime in the future. The cost of this will vary depending upon whether or not the modifications entail new burners or simply modification of existing burners.

Windbox modifications – The windbox of the boiler is the common plenum that provides combustion air to the burners. In some cases it is necessary to modify the windbox to assure proper distribution of combustion air after burners are replaced or modified. But, for the most part, any windbox modifications are typically minor. Extensive windbox modifications can increase the expense substantially, but are rarely needed.

Controls and sensors – Gas flames are physically different than coal flames, being far less luminous. New flame detectors and controls will be required for the gas-fired burners.

Flue Gas recirculation (FGR) – FGR may be used for furnace gas temperature control and also for NOx control. FGR is not necessary in most cases, but has been needed in some cases. For example, if the reason for the conversion is partly motivated by a need to reduce NOx emissions, FGR will help reduce emissions lower and over a wider load range. FGR, if installed, can increase the cost substantially because it may entail additional fans, ductwork, modifications to the boiler, and fan electrical supply and controls.

Furnace modifications – There are several factors that impact a gas versus coal furnace design. A furnace designed to burn coal tends to be larger than one designed to burn gas. Also, the presence of some slag on the walls of a coal furnace will impact heat transfer, and this slag will not be present when firing natural gas. Moreover, heat transfer in the furnace is affected by the luminosity of the flame, which is much greater for a coal flame. Finally, the spacing of convective pass tubing of a coal furnace is not as close in order to allow for possible ash build up. As a result of all of these effects, the heat balance between steam generation in the furnace and superheat and reheat in the convective section will be impacted to some degree when a coal fired boiler is converted to fire 100% natural gas. This must be evaluated on a case-by-case basis for each conversion project. To the degree that these effects are significant, modifications in heat transfer surface may be necessary or beneficial.

Air preheater modifications/replacement – Due to the cleaner nature of the exhaust from the natural gas flame and the fact that the exhaust gas may have more moisture in it than a coal flame (some coals, like lignite, have high moisture content while others, like bituminous, have lower moisture content), it may be beneficial to modify the air preheater to achieve better boiler efficiency. This can be one of the more expensive modifications. In most cases, it is not possible to justify this added cost unless the unit will be heavily operated.

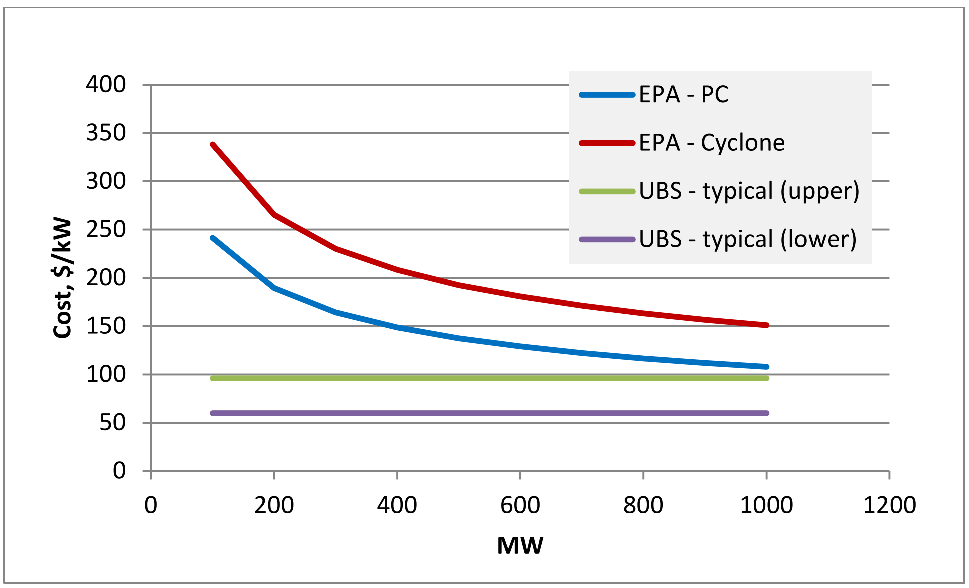
With few exceptions, these modifications can be incorporated into other planned outages, so that the impact on the plant operation is small or negligible.

EPA estimated that the cost of the boiler modifications needed for a gas conversion are as shown in Figure 2 for pulverized coal (PC) and cyclone boilers.[10] Costs are represented in terms of $/kW as a function of size (MW). The cost function covers new gas burners and piping, windbox modifications, air heater upgrades, gas recirculating fans, and control system

[10] Developed from equations in Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units Docket ID No. EPA-HQ-OAR-2013-0602 GHG Abatement Measures, page 6-4

modifications.[11] *However, in most cases all of these modifications, many of which drive up cost considerably, are not necessary.* For example, air preheater upgrades and flue gas recirculation, while often desirable, are often not performed because of the substantial added cost. Conversion to natural gas could be as simple as installing a gas nozzle on an existing coal burner and tying into the existing natural gas supply system.[12] While EPA's estimates included all of the possible modifications and have much higher cost, typical gas conversion costs are in the range of $50/kW-$80/kW for the material and installation of the boiler modifications and roughly another 15-20% to cover owner's costs, and these costs are also shown on Figure 2 as well.[13] Therefore, depending upon the extent of the modifications needed, the cost may vary quite a bit. Assuming a capital cost of $100/kW, a capital recovery factor of 13% and a capacity factor of 50%, this equates to a levelized cost of about $3/MWh. The cost of increasing natural gas supply to the plant would be in addition to the costs of the boiler modifications.

Figure 2. Estimated cost for the boiler modifications associated with gas conversions.
Note: EPA estimates include all possible modifications, while those cited to UBS are typical



Fuel costs will generally increase because natural gas is more expensive than coal. The difference will depend upon the relative cost of the fuels for the specific plant. For example, for facilities that burn Central Appalachian coal, the difference in fuel cost between natural gas and

[11] http://www.epa.gov/powersectormodeling/docs/v513/Chapter_5.pdf
[12] Brian Reinhart, Alap Shah, Mark Dittus, Ken Nowling, Bob Slettehaugh, "Paper of the Year: A Case Study on Coal to Natural Gas Fuel Switch", POWER-GEN International 2012.
[13] UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013

coal is much less than that for a boiler that burns local, surface-mined coal. The increased fuel costs will be partially offset by reduced operation and maintenance costs, as discussed earlier and examined in some of the Case Studies later in this report.

Modifications to the boiler for natural gas cofiring

Modifying a boiler for natural gas cofiring can sometimes be done with fairly minimal modifications, depending upon the intent and how much gas will be co-fired. Facilities that start up on gas have the ability to burn at least 10% of the heat input on gas through the gas igniters. In this case gas cofiring up to the capacity of the gas igniters can be performed at no additional capital cost. In some cases, the boiler is designed to accept higher levels of natural gas without any additional modifications. Some equipment that may be added include:

Gas injectors - If natural gas is used for reburning, modifications to the upper furnace area will be necessary, and will, in most cases, require some pressure part changes to install locations for the gas injectors and perhaps overfire air.

Sensors and controls – Sensors are needed to monitor flames for the purpose of safety.

As noted earlier in this document, gas reburning was used commercially and demonstrated commercially in the 1990s as a means of NOx control. The cost of natural gas reburning was typically estimated to be on the order of $15/kW for normal reburning, which included the gas injectors, overfire air, and associated controls. Using the Chemical Engineering Plant Cost Index (CEPCI) to escalate these costs to 2014 costs results in about $23/kW.[14] Actual costs would be less in many cases because today many boilers are already equipped with overfire air, and that part of the modification may be unnecessary today. In the case of fuel lean gas reburning, the only boiler modification is associated with the gas injectors, and overfire air is not necessary. As a result, fuel lean gas reburn would be a slightly less expensive retrofit.

Gas supply modifications

If the plant does not currently have adequate natural gas available on site for cofiring or for natural gas conversion, it will be necessary to increase supply. Natural gas must be brought on site through a pipeline. To keep gas prices reasonable and to have adequate gas capacity, power plants prefer to have natural gas delivered from a large, interstate pipeline rather than through a local distribution network. This requires pressure reducing capability as well as a

[14] Applying 1995 CEPCI of 381.1 and May 2014 CEPCI of 574.3 to $15/kW results in a cost of $22.6/kW in 2014

pipeline sized adequately for the demand. Depending upon the size of the power plant and the increase in demand placed on the interstate pipeline, it may be necessary for the interstate pipeline to increase its capacity as well. Areas around the boiler where gas piping will be added and where there is a risk of any gas leakage may be classified as areas with a risk of explosion hazard. In order to address the risk of explosion hazard, this may even entail making changes to electrical equipment in the vicinity of where there may be a risk of gas leakage.

The costs of these gas supply modifications will be driven primary by distance over which the gas line connecting the plant to the interstate pipleline must be built and the quantity of gas that must be moved. Estimates will vary based upon the needs for rights of way and other local factors, but are in the range of about $1 million per mile, with some cases more expensive.[15] EPA made estimates for over 400 plants. The costs were developed for each unit at the plant based upon the proximity to a natural gas pipeline and the estimated quantity of gas needed.[16] ATP calculated the cost per mile on a unit basis by dividing the total cost of the pipeline per unit by the mileage to the pipeline and determined the cost on a plant basis by simply adding up the cost for each unit at each plant and dividing by the mileage. In this respect the plant cost will be conservatively high because separate lines for individual units could be combined into a single, larger line at less cost. The results are shown in Table 4. From these values, a cost in the range of about $1 million to $1.5 million per mile might be regarded as typical, although for some cases the costs may be outside this range.

Table 4. Estimated cost of natural gas pipeline, developed from EPA data.

	$million/mile	
	unit basis	**plant basis**
median	$0.85	$1.60
average	$0.83	$1.97

There have been a number of announced and completed natural gas conversion projects and they are listed in Table 5. This table is not a complete listing of all announced projects, only those that have been verified. In some cases projects were announced and then cancelled. In other cases the decision was made to convert to natural gas combined cycle or a combustion turbine. It is also possible that some announced projects may not be on this list.

[15] UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013

[16] May be downloaded at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

Table 5. Summary of announced coal to gas conversion or cofiring projects

State	Plant Name	Unit	MW	Status or completion date
AL	E C Gaston	1	254	Complete by 2015[17] ~30 mile pipeline
AL	E C Gaston	2	256	
AL	E C Gaston	3	254	
AL	E C Gaston	4	256	
AL	Greene County	1	254	Complete by 2016[18]
AL	Greene County	2	243	
AZ	Cholla	1	116	Convert in 2025[19]
AZ	Cholla	3	271	
AZ	Sundt, Irvington	4	156	Complete by 2018[20]
CO	Cherokee	4	352	Complete 2017[21] 34 mi. pipeline
DE	Edge Moor	3	86	Completed
DE	Edge Moor	4	174	Completed
GA	Yates	Y6BR	352	Complete by 2015[17]
GA	Yates	Y7BR	355	
IL	Joliet	71	250	Complete by 2016[22]
IL	Joliet	72	251	
IL	Joliet	81	252	
IL	Joliet	82	253	
IL	Joliet	9	590	
IN	IPL - Harding Street Station (EW Stout)	5	106	Complete by 2016[23]
IN	IPL - Harding Street Station (EW Stout)	6	106	
IN	IPL - Harding Street Station (EW Stout)	7	435	
IA	Riverside	9	128	Complete by 2016[24]
MS	Watson	4	232	Complete by April 2015[18]
MS	Watson	5	474	
MN	Hoot Lake	2	58	Complete by 2020[25]
MN	Hoot Lake	3	80	
MN	Laskin Energy Center	1	55	Complete in 2015[26]
MN	Laskin Energy Center	2	51	
MO	Meramec	1	119	Units 1 & 2 to be converted in 2016[27]
MO	Meramec	2	120	

17 Georgia Power 2013 Integrated Resource Plan
18 http://online.wsj.com/articles/sierra-club-ends-opposition-to-southern-co-clean-coal-plant-in-mississippi-1407184753
19 http://www.azcentral.com/story/money/business/2014/09/11/aps-plans-close-one-four-generators-cholla-power-plant/15455255/
20 http://www.epa.gov/region9/air/actions/pdf/az/azfip-finalrule-june2014.pdf
http://tucson.com/business/local/tep-south-side-plant-to-stop-coal-burning-by-end/article_7db6cd7c-e2ed-5a31-88d2-198b22333ebc.html
21 http://www.xcelenergycherokeepipeline.com/
22 NRG Energy Investor Presentation, September 2014
23 http://www.ibj.com/ipl-moves-to-drop-coal-from-harding-street-power-plant/PARAMS/article/49080
24 http://qctimes.com/news/local/riverside-plant-to-switch-from-coal-to-gas/article_5d4b8f40-6511-11e2-b7cd-0019bb2963f4.html
25 http://www.mprnews.org/story/2013/01/31/business/hoot-lake-plant-stop-burning-coal
26 http://www.allete.com/our_businesses/minnesota_power.php
http://finance-commerce.com/2013/01/minnesota-power-converting-coal-plant-to-natural-gas/
27 http://phx.corporate-ir.net/phoenix.zhtml?c=91845&p=irol-newsArticle&ID=1972924&highlight=

State	Plant Name	Unit	MW	Status or completion date
NJ	Deepwater	1	82	Completed
NJ	Deepwater	8	73	Completed
NY	Dunkirk	1	75	Requires construction of 9 or 11 mile pipeline. To be complete 2015[28]
NY	Dunkirk	2	75	
NY	Dunkirk	3	185	
NY	Dunkirk	4	185	
OH	Avon Lake	7	96	To be complete 2016, ~20 mile pipeline to be built.[29]
OH	Avon Lake	9	640	
OK	Muskogee	4	505	Complete by 2017[30]
OK	Muskogee	5	517	
PA	Brunner Island	1	312	Pipeline being added, unclear which units to be converted or use of cofiring [31, 32]
PA	Brunner Island	2	371	
PA	Brunner Island	3	744	
PA	New Castle	3	93	Complete by 2016[33]
PA	New Castle	4	95	
PA	New Castle	5	132	
VA	Clinch River	1	230	Two of three to be converted by September 2015, third to shutdown[34]
VA	Clinch River	2	230	
VA	Clinch River	3	230	
WI	Blount Street	8	51	Completed[35]
WI	Blount Street	9	50	
WI	Valley (WEPCO)	1	67	Complete in 2015/16
WI	Valley (WEPCO)	2	67	
WI	Valley (WEPCO)	3	67	
WI	Valley (WEPCO)	4	67	
WY	Naughton	3	330	By 2017[36]
Notes: This table is likely to be an incomplete list of all announced projects. Also, an effort was made to verify that the units on this table were not subsequently retired or are not being converted to combustion turbines or combined cycle.				

Other conversions that were announced, but the owners later decided to retire the units include Big Sandy and Muskingum River plants. In some other cases the facility owners chose to

---

[28] http://www.buffalonews.com/business/residents-tell-state-to-make-decision-on-duelling-dunkirk-plant-pipeline-plans-20141023

[29] BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO, In the Matter of the Application of NRG Ohio Pipeline Company LLC for Authority to Operate as an Ohio Pipeline Company 11/27/2013 10:16:21 AM in Case No(s). 13-2315-PL-ACE
http://www.cleveland.com/business/index.ssf/2014/02/nrg_energy_plans_to_build_natu.html

[30] http://newsok.com/oklahoma-gas-and-electric-co.-files-1.1-billion-application-for-environmental-compliance-replacement-natural-gas-plant/article/5134375

[31] http://www.power-eng.com/articles/2014/09/ppl-permits-gas-firing-at-big-brunner-island-coal-plant.html

[32] http://www.elp.com/articles/2014/09/ppl-permits-gas-firing-at-big-brunner-island-coal-plant.html

[33] http://www.cleveland.com/business/index.ssf/2014/02/nrg_energy_plans_to_build_natu.html
http://dis.puc.state.oh.us/TiffToPDf/A1001001A13K27B01622D11734.pdf

[34] http://www.platts.com/latest-news/coal/louisvillekentucky/aeps-clinch-river-power-plant-in-virginia-to-21100599

[35] http://host.madison.com/business/in-march-blount-street-plant-to-make-gas-its-primary/article_28618898-0489-11df-8a48-001cc4c002e0.html

[36] Pacificorp 2013 Integrated Resource Plan, Public Session Technical Workshop, July 8, 2013

retire the boiler and replace it with natural gas combined cycle or combustion turbines. In the case of Avon Lake, at one point it was expected that these units would be retired, but a more recent decision was made to convert this plant to natural gas.

The natural gas conversions that have been recently announced were primarily in response to tightened environmental regulations, such as the Mercury and Air Toxic Standards (MATS) or Regional Haze Rule (RHR). The owners determined that a natural gas conversion was the lowest cost approach for compliance with these rules. In addition, it is likely that some owners factored in the likely costs of compliance with stricter water pollution rules relating to ash management and future CO_2 emission limits.

As shown, these conversions span a wide range of locations and a wide range of plant sizes and coal types (bituminous and subbituminous). Notably, there are no lignite-fired units. Lignite-fired boilers are mine-mouth plants and therefore have very low fuel costs. The largest plants shown here are over 500 MW and the smallest units on the table are only about 50 MW. There are smaller units still that have been or will be converted to natural gas. In the following section case studies will be examined for the following facilities: Gaston, Irvington, Cherokee, Edge Moor, Yates, Harding Street, Laskin, Meramec, Deepwater, Avon Lake, Muskogee, Brunner Island, New Castle, Clinch River, Blount Street, Valley and Naughton.

Time frame for projects

In general, the boiler modifications will require under a year to perform once the contract is released, including detailed design procurement and installation,[37] and additional time should be provided for activities by the owner prior to placing the order – perhaps 18 months altogether for all activities relating to the boiler (excluding permitting). The impact to boiler outage should be no more than a few weeks, which can normally be incorporated into typical outage times. However, if the modifications are relatively modest, the time could be much less and should have no impact to outages.

The time-limiting factor may be the pipeline-related activities. If a new pipeline must be built, as opposed to expansion of existing pipeline, it is necessary to gain rights of way. In the case of the 34 mile pipeline for the Cherokee plant, construction started in early 2014 and was expected to be complete in October 2014 – under one year. Of course, prior to construction it

---

[37] UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013

was necessary to obtain the necessary rights of way and construction permits. The project was initially approved by the Colorado Public Utilities Commission in late 2010.[38] Not factoring in the work performed prior to that agreement (no doubt preliminary engineering and feasibility studies were necessary) the experience at Cherokee indicates for such an extensive pipeline four years might be needed – although construction is less than a year. On the other hand some other pipeline projects may be moving along a faster track. Another example of a plant that requires a new pipeline is Avon Lake in Ohio. In February 2014 the Public Utilities Commission of Ohio approved of NRG Gas Pipeline as a utility that could build a new, roughly 20-mile pipeline along one of two routes proposed in their November 2013 application.[39, 40] The company is working to acquire the needed property and the plant should be operating on natural gas by spring 2016.[41, 42] Boiler modifications could be performed concurrently with the pipeline construction. As a result, total construction activities should be a year or less for most facilities with engineering and other necessary planning activities preceding them.

The Dunkirk station conversion near Buffalo, NY is still another project that is in the works. Dunkirk is owned by NRG Energy. One of two alternative pipeline proposals will be selected by the New York State Public Service Commission. One, by National Fuel Gas Company, is a 9.3 mile pipeline that would cost an estimated $34.5 million. Another is an 11.3 mile pipeline by the plant owner's affiliate, Dunkirk Gas Corporation, at a yet undetermined cost. The project is planned to be completed in September 2015.[43] This project, then, will require less than a year to construct and put in place once the pipeline alternative is selected. In addition, there was planning and other preparation that likely required a year or so.

---

[38] http://www.xcelenergy.com/Environment/Doing_Our_Part/Clean_Air_Projects/Colorado_Clean_Air_-_Clean_Jobs_Plan

[39] http://www.cleveland.com/business/index.ssf/2014/02/nrg_energy_plans_to_build_natu.html

[40] BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO, In the Matter of the Application of NRG Ohio Pipeline Company LLC for Authority to Operate as an Ohio Pipeline Company, Case No. 13-2315-PL-ACE, 11/27/2013 10:16:21 AM

[41] http://chronicle.northcoastnow.com/2014/08/28/neighbors-learn-planned-pipeline/

[42] http://avonlakefacts.com/history.html

[43] http://www.buffalonews.com/business/residents-tell-state-to-make-decision-on-duelling-dunkirk-plant-pipeline-plans-20141023

Case Studies

The following are plants where natural gas conversions have been performed or are planned. The conversions being performed at these facilities will be examined in more detail in the following Case Studies.

- Gaston
- Irvington
- Cherokee
- Edge Moor
- Yates
- Harding Street
- Laskin
- Meramec
- Deepwater
- Avon Lake
- Muskogee
- Brunner Island
- New Castle
- Clinch River
- Blount Street
- Valley
- Naughton

Case Study 1. Plant Gaston Units 1-4, Alabama

Plant Gaston, shown in Figure 3, is located near Shelby, Alabama and operated by Alabama Power, part of Southern Company. In May 2012, Alabama Power announced its plans to convert units 1-4 at roughly 250 MW each to natural gas rather than continue to operate on coal and install pollution controls needed to comply with the Mercury and Air Toxics Standards (MATS). Construction on the project commenced in early 2014 with blasting completed by May 2014.[44] The project is planned for completion by 2015 – or less than three years from announcement to completion. Assuming a year for evaluation, this indicates a total time likely of under four years. Unit 5, which is larger, will continue to burn coal. Because the facility did not originally have adequate natural gas on site (startup fuel was oil), it is necessary to construct a 30-mile natural gas pipeline to connect it to a gas supply located about 30 miles south of the plant.

Plant Gaston units 1-4 are all wall-fired boilers that burn bituminous coal. Table 6 shows information on each of the units at Plant Gaston including 2013 calculated emission rates in lb/MWh for SO_2, NOx and CO_2 based upon information reported to US EPA under the Title IV program. The 2013 estimated capacity factors for the units are in the range of 20%-30%.[45] As such, these are not base loaded and primarily cycle to meet load demands.

Cost information on the project was redacted from the publicly available Integrated Resource Planning documents and is therefore not available.

Table 6. Information on Plant Gaston units 1-4, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
E C Gaston	1	254	AL	wall	Bit.	9837	28%	1960	29	4.0	2,154
	2	256	AL	wall	Bit.	9928	27%	1960	29	4.1	2,186
	3	254	AL	wall	Bit.	9843	21%	1961	25	4.4	2,337
	4	256	AL	wall	Bit.	9766	27%	1962	27	3.7	1,962

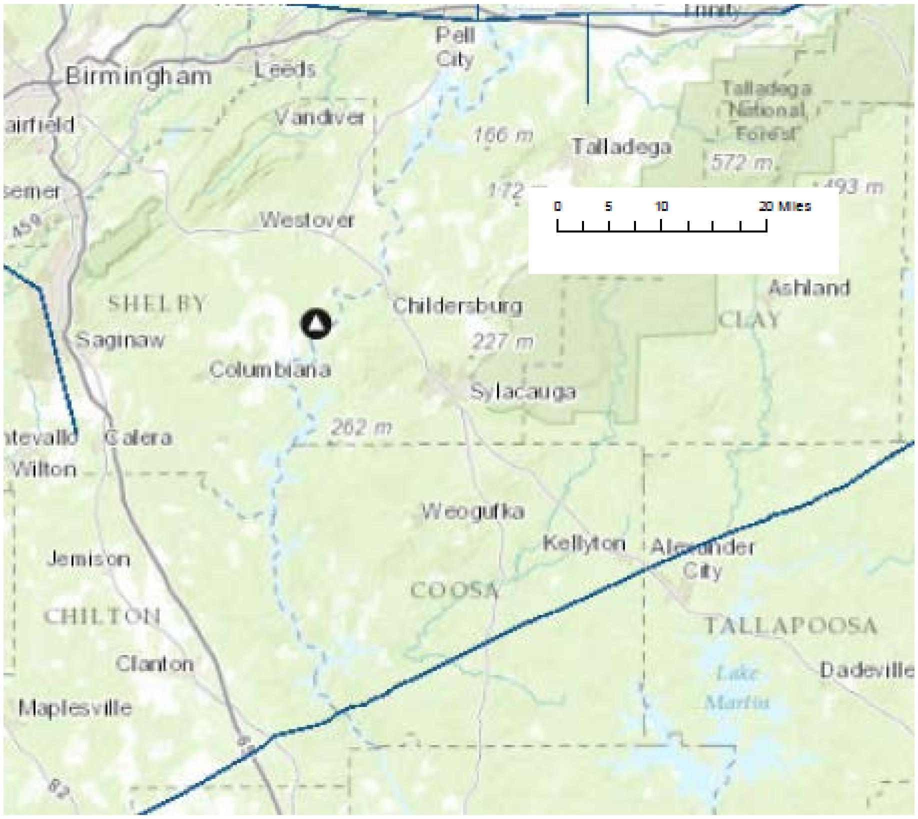
[44] http://www.dykon-blasting.com/Archives/Latex-Gaston/index.htm

[45] Capacity factor is estimated from reported 2013 gross output and rated capacity

Figure 3. Plant Gaston.

Figure 4 shows the location of Plant Gaston (the black circle) compared to the Transcontinental interstate gas pipeline (the blue line). Plant Gaston, located southeast of Birmingham, will be connected to the interstate gas pipeline located to the south that passes through Coosa County.

Figure 4. Location of Plant Gaston (black circle with white triangle) and interstate gas pipeline (blue line) it will tie in to. (Source, Energy Information Administration)



Case Study 2. Irvington (Sundt) unit 4, Arizona

Irvington Unit 4 (shown in the foreground of Figure 5) is the sole coal-fired unit at the otherwise gas-fired Irvington (also known as Sundt) station. The facility was originally all gas fired, but unit 4 was converted to coal in the 1980s.[46] After over 30 years of coal operation, Tucson Electric has agreed to convert the 156 MW unit 4 back to natural gas firing, consistent with the other units at the site, as part of its plan to comply with Arizona's regional haze requirements.

Figure 5. Irvington station with Unit 4 in foreground

Irvington unit 4 is a wall-fired boiler that, according to EPA's NEEDS v5.13 database, burns bituminous and subbituminous coal. Table 7 shows information on Irvington 4 including 2013 calculated emission rates in lb/MWh for SO_2, NOx and CO_2 based upon information reported to US EPA under the Title IV program.

[46] Tucson Electric Power Irvington Generating Station Air Quality Permit # 1052 TECHNICAL SUPPORT DOCUMENT (TSD) May 18, 2007 http://pima.gov/deq/permits/PDF/1052TSD.pdf

The conversion was motivated as a lower cost approach than SCR to reduce NOx emissions for compliance with Regional Haze Rule requirements and will be completed before the end of 2017. Tucson Electric reached the agreement with US EPA to do the conversion in January 2014. Because natural gas is on site and is already available to unit 4, which was originally a gas unit, the cost of converting was very low, reportedly on the order of hundreds of thousands of dollars.[47]

Table 7. Information on Irvington unit 4, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Irvington	4	156	AZ	wall	Bit., Subbit.	10732	32%	1967	6.3	4.6	2,123

[47] http://tucson.com/business/local/tep-south-side-plant-to-stop-coal-burning-by-end/article_7db6cd7c-e2ed-5a31-88d2-198b22333ebc.html

Case Study 3. Cherokee unit 4, Colorado

Cherokee station, operated by Xcel Energy, is located just north of Denver, CO. Xcel Energy has agreed to shut down units 1-3, convert 352 MW unit 4 to natural gas and will build a new 569 MW natural gas combined cycle plant on the site. Units 1-2 are already retired. Unit 3 will be retired in 2015. Unit four is shown in the foreground of Figure 6 and its conversion to natural gas will be completed in 2017.

Figure 6. Cherokee generating station, with unit 4 in the foreground.

The project required installation of 34 miles of new, 24-inch steel, high-pressure natural gas transmission pipeline from a new Fort Lupton natural gas metering facility, as shown in Figure 7. Work on the pipeline commenced early 2014 and is completed, in time for the 2015 start-up of the combined cycle plant.[48, 49] The total cost of the pipeline was $110 million to include design, land acquisition, construction and testing.[50]

---

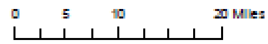
[48] http://www.xcelenergycherokeepipeline.com/

[49] http://www.mcilvainecompany.com/Decision_Tree/subscriber/Tree/DescriptionTextLinks/Power%20Projects/Kiewit%20569%20MW%20Natural%20Gas-fired%20Cherokee%20Power%20Plant%20to%20Use%20Less%20Water%20than%20Present.htm

[50] http://www.xcelenergycherokeepipeline.com/

Figure 7. Cherokee station (black circle with white triangle near Denver) in relation to Fort Upton natural gas metering facility (circled in red)

Source: Energy Information Administration



Cherokee unit 4 is a tangentially-fired boiler that, according to EPA's NEEDS v5.13 database, burns bituminous and subbituminous coal. Table 8 shows information on Cherokee 4 including 2013 calculated emission rates in lb/MWh for SO_2, NOx and CO_2 and capacity factor based upon information reported to US EPA under the Title IV program.

Cherokee unit 4 is a BART affected unit, and the timing of the gas conversion is consistent with the need to comply with BART.

Table 8. Information on Cherokee unit 4, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Cherokee	4	352	CO	tangential	Bit., Subbit.	10,880	68%	1969	1.6	3.0	2,081

Case Study 4. Edge Moor Power Plant units 3 and 4, Delaware

After Conectiv sold the Edge Moor plant (shown in Figure 8) to Calpine in 2010, Calpine made the decision to convert the two coal-fired boilers on the site to natural gas. Both units are tangentially fired boilers that burned bituminous coal. Unit 3 is 86 MW and Unit 4 is 174 MW. Natural gas was already available on site.

Figure 8. Edge Moor Power Plant

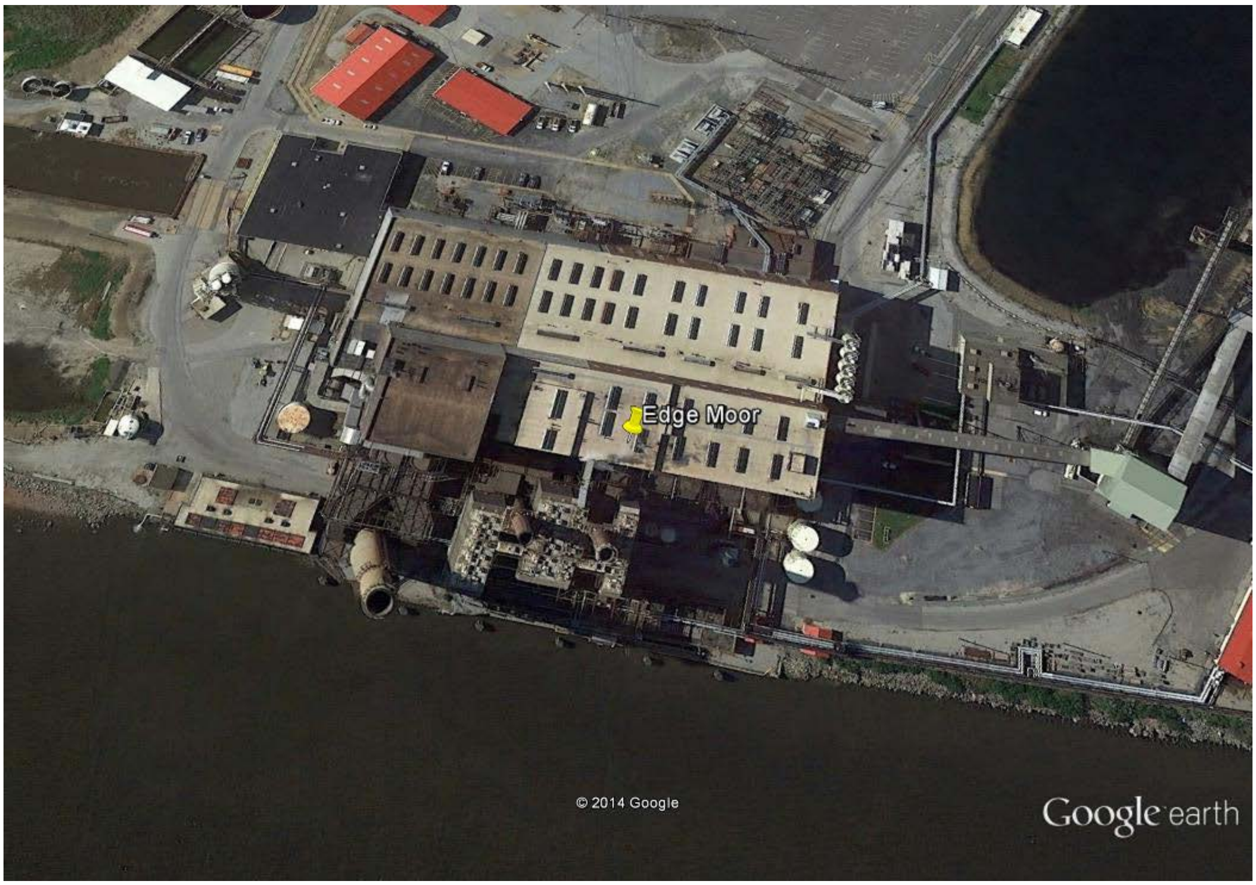


Table 9 shows information on the two units, to include a comparison of emissions between 2009 (when coal was last fired for a full year) and 2013 (when the facility burned 100% natural gas). As shown, the emissions of all pollutants dropped dramatically, 100% drop in SO_2 emission rate, 50% or better reduction in NOx emission rate, and 45% reduction in CO_2 emission rate. Also, at only 10% capacity factor, the units are operated only as peaking units.

Table 9. Information on Edge Moor units 3 and 4, to include 2009 and 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	Heat Rate	2013 Cap. Fctr.	Yr on line	2009 lb/MWh SO2	2009 lb/MWh NOx	2009 lb/MWh CO2	2013 lb/MWh SO2	2013 lb/MWh NOx	2013 lb/MWh CO2
Edge Moor	3	86	DE	tangential	Bit.	11,954	10%	1957	5.4	1.6	2,327	0.0	0.8	1,261
Edge Moor	4	174	DE	tangential	Bit.	11,279	10%	1966	8.5	1.7	1,954	0.0	0.7	1,081

Case Study 5. Yates units 6 and 7, Georgia

Plant Yates is operated by Georgia power and is located southwest of Atlanta. Georgia Power decided to convert both roughly 350 MW units 6 & 7, shown in Figure 9, to natural gas rather than install additional controls for MATS compliance. The plants are already equipped to burn some gas and routinely cofired it during the peak months of May through September,[51] but will need to make some modifications in order to burn gas full time, including installation of oxidation catalyst.[52]

Figure 9. Yates units 6 & 7,

[51] 2013 EIA Form 923 data shows 1,320,400 mcf of natural gas burned during those months
[52] http http://www.bentley.com/en-US/Engineering+Architecture+Construction+Software+Resources/User+Stories/Be+Inspired+Project+Portfolios/United+States/Plant+Yates+Southern+Company.htm://www.times-herald.com/local/20140330-Plant-Yates-update

Cost information on the project was redacted from the publicly available Integrated Resource Planning documents; however, some estimates place the project cost at $40 million, or roughly $57/kW.[53]

Table 10 shows data on the two tangentially-fired units, to include 2013 emission rates and capacity factor. As shown, both units had been operated at lower capacity factors, with most operation during the summer peaking months.

Table 10. Information on Plant Yates 6 & 7, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh		
									2013 SO2	2013 NOx	2013 CO2
Yates	Y6BR	352	GA	tangential	Bit.	10492	29%	1974	22.0	2.6	1,966
Yates	Y7BR	355	GA	tangential	Bit.	10487	15%	1974	21.7	2.2	1,970

Figure 10 shows the location of Plant Yates (black circle with white triangle) relative to Atlanta and to the nearby Transco Interstate gas pipeline. There is a 6.5 mile, 370 MMCFD pipeline from the Transco pipeline to Plant Yates that was installed in 1999.[54]

Figure 10. Plant Yates (black circle with white triangle) and nearby interstate gas pipelines (blue lines).

53 http://www.times-herald.com/local/20140330-Plant-Yates-update
54 http://www.georgiapower.com/about-energy/energy-sources/natural-gas-safety.cshtml

Case Study 6. Harding Street Station, Indiana

All remaining operable boilers at Harding Street Station, located in Indianapolis, will be retrofit to burn natural gas by 2016 in lieu of installing controls for MATS compliance or new water pollution equipment. The three tangentially-fired boilers, to the right in Figure 11, with a combined output of nearly 550 MW were operated in 2013 at capacity factors of about 70% or greater in 2013. The project will add roughly $1 to the average ratepayer's monthly bill, but alternatives that would have continued use of coal would have had a greater cost.[55]

Figure 11. Harding Street Station – Units 5-7 to the right

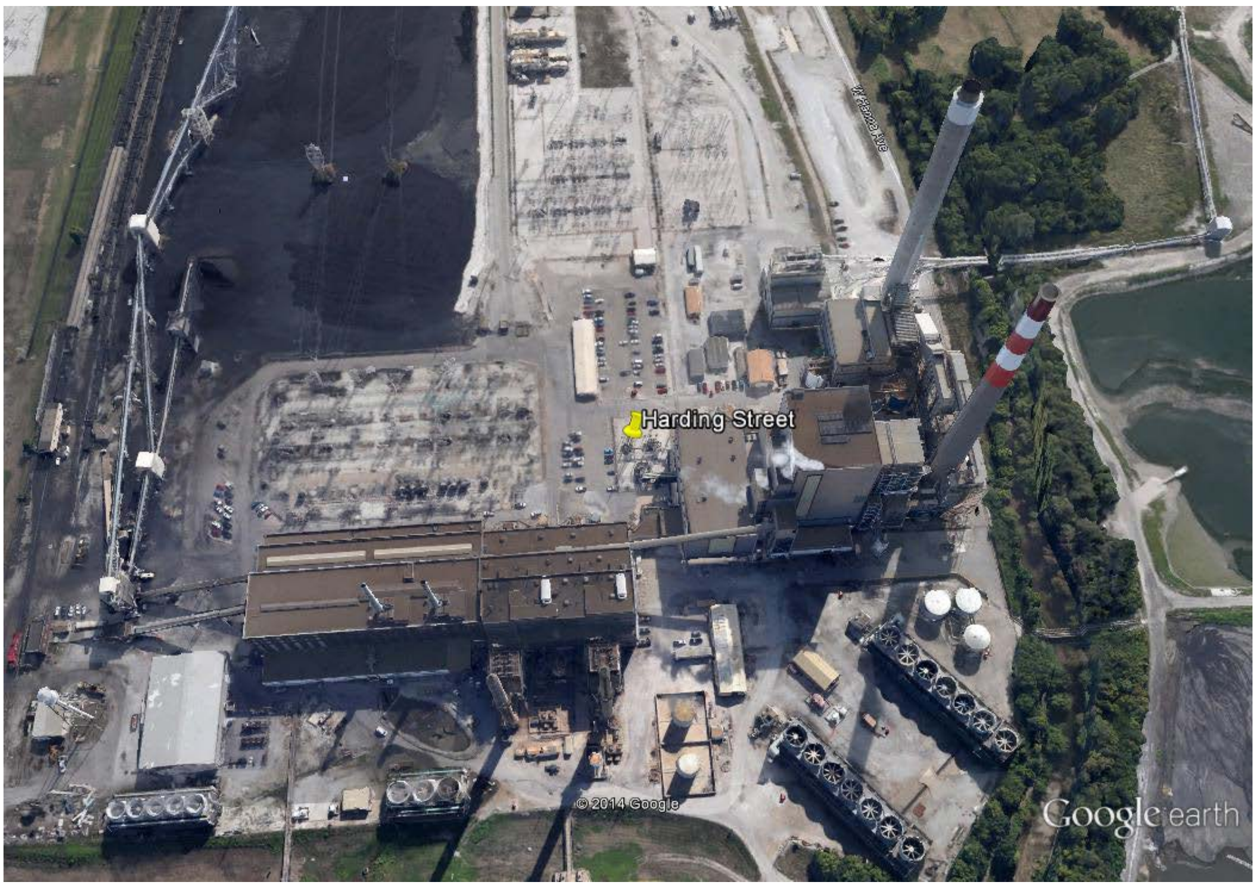


Table 11 shows data on the three units, to include 2013 emission rates and capacity factor. As shown, all three units had been operated at factors of about 70% or greater, suggesting base load or very limited load cycling. Natural gas was already located on site, as the facility has six

[55] http://www.ibj.com/ipl-moves-to-drop-coal-from-harding-street-power-plant/PARAMS/article/49080

combustion turbines and two small natural gas fired boilers that based upon review of EPA's Air Markets Program Data do not appear to have operated on coal at any time at least since 1990.

Table 11. Information on Harding Street Station units 5, 6, 7, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh		
									2013 SO2	2013 NOx	2013 CO2
Harding Street Station	5	106	IN	tangential	Bit.	10541	73%	1958	39.3	2.4	2,051
	6	106	IN	tangential	Bit.	10491	72%	1961	37.9	2.4	1,983
	7	435	IN	tangential	Bit.	10517	82%	1973	1.3	1.7	2,059

Case Study 7. Laskin Energy Center, Minnesota

Minnesota Power will be converting its two 61-year old, 55 MW boilers at Laskin Energy Center, shown in Figure 12, to natural gas in 2015 in lieu of installing controls for MATS compliance. The retrofit is expected to be completed over a routine outage at a projected cost of roughly $15 million, or about $136/kW for all modifications.[56]

Figure 12. Laskin Energy Center

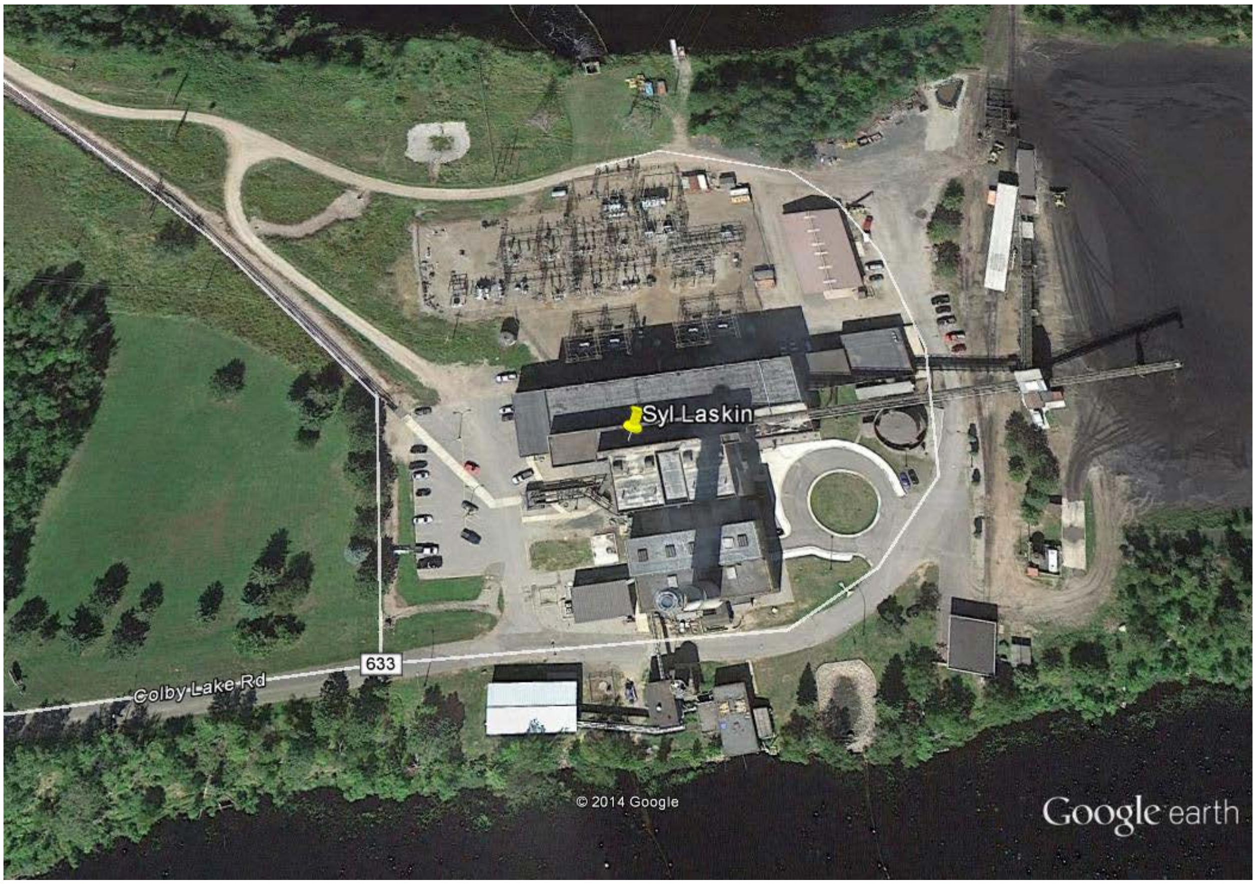


Table 12 shows data on the two units at Laskin, to include 2013 capacity factor, current heat rate (from NEEDS v5.13) and 2013 emission rates. According to NEEDS v5.13, the two units fired bituminous and subbituminous coal and used a wet scrubber for PM control. Capacity factors in 2013 are 50%-60%, indicating that these units perform load following duty but also operate a substantial amount of time.

[56] http://finance-commerce.com/2013/01/minnesota-power-converting-coal-plant-to-natural-gas/

Table 12. Information on Laskin units 1 & 2, to include 2013 emission rates

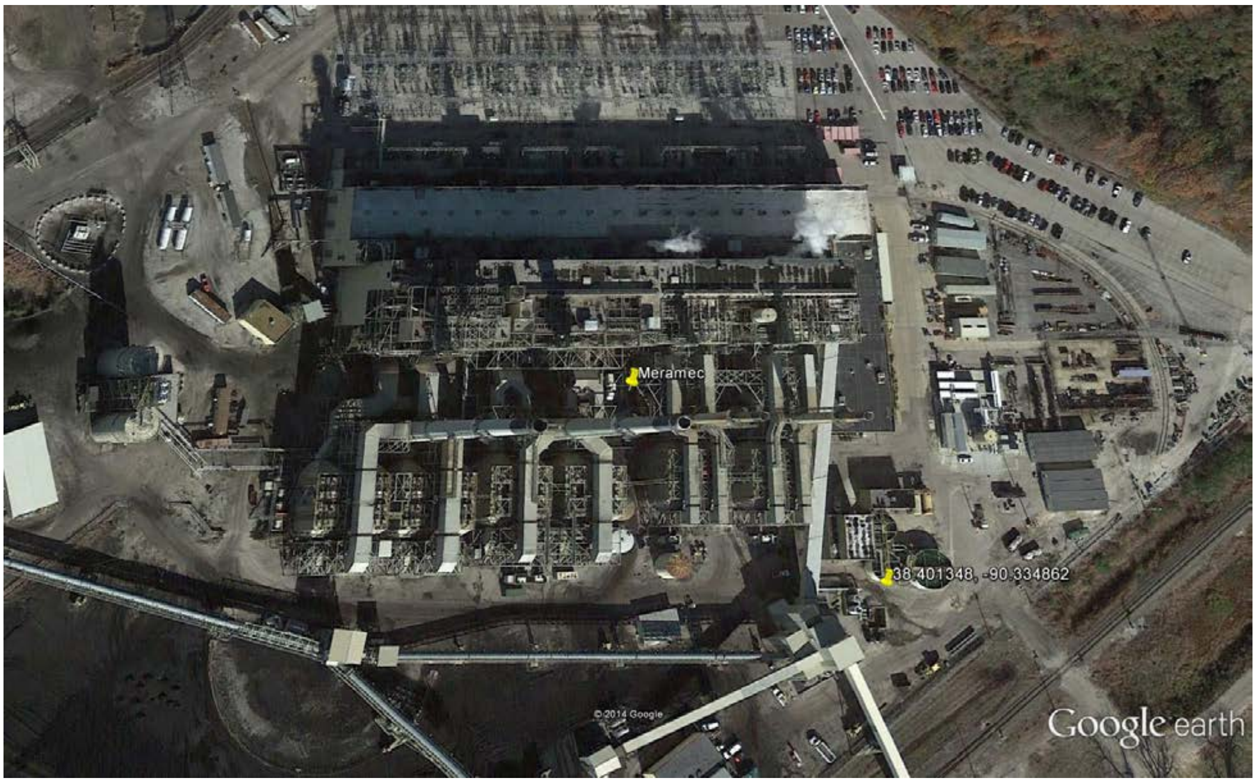
Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Laskin	1	55	MN	Tangential	Bit., Subbit.	12783	56%	1953	1.5	2.0	2,463
	2	51	MN	Tangential	Bit., Subbit.	12875	58%	1953	1.5	2.0	2,456

Case Study 8. Meramec Power Plant, Missouri

Meramec Power plant shown in Figure 13, has four units. In their 2014 Integrated Resource Plan (IRP), Ameren Missouri announced plans to convert units 1 and 2 to natural gas in 2015 and to retire all four Meramec units in 2022.[57] Although the plant already uses some natural gas, it is currently only utilized for the combustion turbines that are on site and for start-up. It is likely that the existing pipeline to the plant may need to be expanded somewhat to provide adequate fuel for units 1 & 2.

The costs of the modifications were not available in the IRP.

Figure 13. Meramec Power Plant



As shown in Figure 14, natural gas is available to the plant from the adjacent interstate pipeline, which is located southwest of Saint Louis where the Meramec River meets the Mississippi River.

[57] Ameren Missouri 2014 Integrated Resource Plan, Chapter 9

Figure 14. Location of Meramec Plant (black circle with white triangle southwest of Saint Louis) and interstate gas pipelines (blue lines).

Table 13 includes data on the two units that are planned for conversion. As shown, these units appear to be load following units based upon their 2013 capacity factor, which is in the 40-50% range.

Table 13. Information on Meramec units 1 & 2, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Meramec	1	119	MO	tang	Bit Subbit	10845	42%	1953	4.7	1.3	2,297
	2	120	MO	tang	Bit, Subbit	10644	48%	1954	4.9	1.3	2,400

Case Study 9. Deepwater, New Jersey

Deepwater power plant on the Delaware River in New Jersey is shown in Figure 15. The units operate as peaking units. Unit 1 is a cyclone boiler that was converted to natural gas many years ago and rarely operates now. Unit 8 was converted from bituminous coal to natural gas in 2010. There was pre-existing natural gas infrastructure and therefore little additional infrastructure to add.

Figure 15. Deepwater Power Plant

The units operate only in a peaking mode, with very low capacity factors in the range of 5% as shown in Table 14.

Table 14. Information on Deepwater unit 8, to include 2009 and 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	Heat Rate	2009 Cap. Fctr.	2013 Cap. Fctr.	Yr on line	2009 lb/MWh			2013 lb/MWh		
										SO2	NOx	CO2	SO2	NOx	CO2
Deepwater	8	73	NJ	wall	Bit.	10,331	11%	5%	1954	9.6	3.6	1,841	0.0	2.2	1,200

Case Study 10. Avon Lake, Ohio

Avon Lake power plant, shown in Figure 16, was destined for shut down by 2015 by previous owner GenOn. NRG Energy, after completing the acquisition of GenOn in December 2012,[58] announced in June 2013 that they would convert the Avon Lake and New Castle plants to natural gas.[59] There was no natural gas on site, and NRG applied in November 2013 to the Public Utilities Commission of Ohio (PUCO) for permission to create and operate its own natural gas pipeline company[60] and received approval in February 2014.[61]

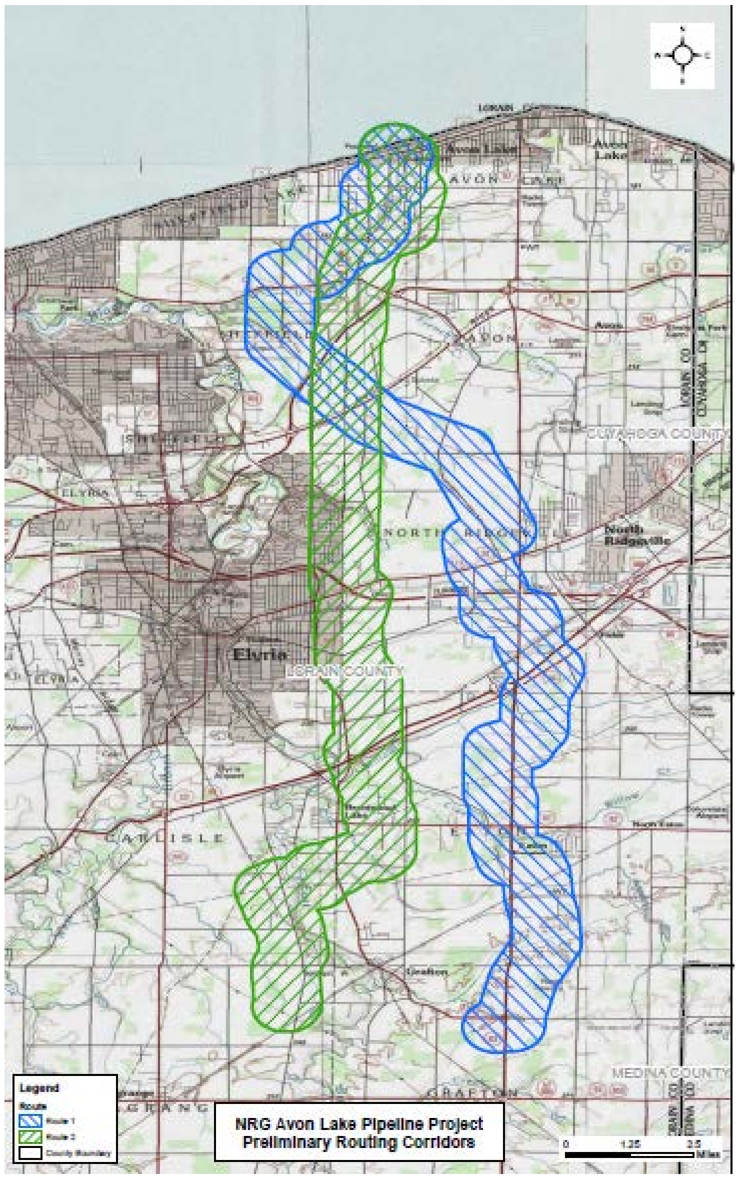
Figure 16. Avon Lake Power Plant

As of August 2014, NRG was obtaining the property rights from landowners in Lorain County, Ohio to build a 20-mile, 24-inch diameter underground pipeline which requires a 50-foot permanent easement for operation and maintenance. The route of the pipeline, with the two original options shown in Figure 17 (the green route is apparently what was selected), would

[58] http://www.bizjournals.com/houston/news/2012/12/14/nrg-genon-merger-complete.html
[59] http://www.newsnet5.com/news/local-news/oh-lorain/avon-lake-power-plant-to-switch-from-coal-to-natural-gas-station-was-slated-to-close-in-2015
[60] BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO In the Matter of the Application of NRG Ohio Pipeline Company LLC for Authority to Operate as an Ohio Pipeline Company, Case No. 13-2315-PL-ACE, APPLICATION, November 27, 2013
[61] http://www.cleveland.com/business/index.ssf/2014/02/nrg_energy_plans_to_build_natu.html

extend south from the power plant to an existing natural gas pipeline owned and operated by Dominion East Ohio. [62] NRG has not disclosed the total cost of the pipeline or power plant conversion.

Figure 17. Two originally proposed routes for the natural gas pipeline for the Avon Lake Power Plant conversion [63]



[62] http://chronicle.northcoastnow.com/2014/08/28/neighbors-learn-planned-pipeline/#

[63] BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO In the Matter of the Application of NRG Ohio Pipeline Company LLC for Authority to Operate as an Ohio Pipeline Company, Case No. 13-2315-PL-ACE, APPLICATION, November 27, 2013

Table 15 shows data on Avon Lake power plant, including 2013 emissions rates. As shown here, Avon Lake 20 is a large unit, over 600 MW, and a low heat rate of under 10,000 Btu/kWh. Unit 12, the larger of the two, had been operating as a load following role as of 2013. Future use is likely to be for peaking or load following use as well.

Table 15. Information on Avon Lake to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh, lb/MMBtu* 2013 SO2	2013 NOx	2013 CO2
Avon Lake	10	96	OH	tang	Bit	12829	10%	1949	3.0	0.4	205
	12	640	OH	cell	Bit	9823	48%	1970	26.3	2.7	1,796

*Avon Lake 10 emission rates in lb/MMBtu and Avon Lake 20 emission rates in lb/MWh

Case Study 11. Muskogee Units 4 & 5, Oklahoma

Oklahoma Gas and Electric will be converting each of the over 500 MW Muskogee Units 4 & 5, shown in Figure 18, to natural gas. According to EIA 923 data, a small amount of natural gas is already burned at the site, likely for start-up, but additional capacity is needed. The 2014 Integrated Resource Plan shows an expected overnight capital cost of $35.7 million per unit. The capital cost includes new pipeline capacity as well as boiler modifications. However, this will provide an expected $5.57 million per unit in annual savings in fixed operating costs and $0.12/MWh in reduced variable operating and maintenance costs. [64] Based upon the 2012 IRP, a new gas pipeline accounted for most of that capital cost.[65] Both Muskogee units 4 & 5 are BART eligible units and the decision to convert the two units to gas in 2018, in time for the January 2019 Regional Haze Rule deadlines, was made after the US Supreme Court declined to consider OG&E's appeal of a lower court ruling. Muskogee unit 6, shown on the left in Figure 18, is not a BART unit and will continue to burn coal.

Figure 18. Muskogee power plant, units 4 & 5 are the two units to the right.

[64] Oklahoma Gas and Electric Company, 2014 Integrated Resource Plan, bear in mind that variable operating costs are separate from fuel costs.
[65] Oklahoma Gas and Electric Company, 2012 Integrated Resource Plan – then estimated the capital cost to be $70 million for the pipeline and $5.7 million for each boiler modification.

Details on the pipeline construction were not available in the IRPs. Figure 19 shows the location of the Muskogee plant relative to the nearby interstate natural gas pipelines. Although it appears that the natural gas pipeline to the west of the plant is very nearby, it is in fact on the other side of the Arkansas River and the city of Muskogee. With the plant conversion announced in 2014 and to be completed in 2018, this indicates a four year period to complete the project, not including any planning activities prior to 2014.

Figure 19. Muskogee Plant (upper black circle with white triangle) and interstate natural gas pipelines (blue lines), source: EIA

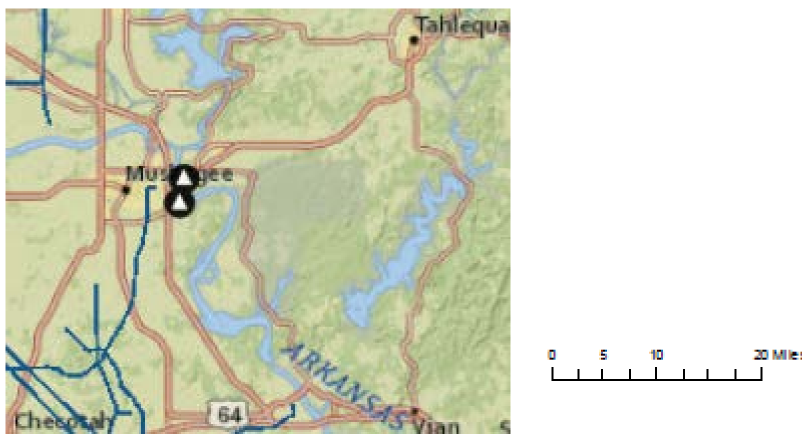


Table 16 shows the information on Muskogee units 4&5, to include 2013 emission rates, estimated capacity factor based upon 2013 Title IV data, and heat rate (from NEEDS v5.13). At over 500 MW each, they are among the largest units identified in this study for coal to gas conversion. Both units burn subbituminous (PRB) coal and in 2013 operated with capacity factors around 50%, indicating that they operated that year in primarily in a load following mode.

Table 16. Information on Muskogee units 4 & 5, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh		
									2013 SO2	2013 NOx	2013 CO2
Muskogee	4	505	OK	tangential	Subbit.	10593	44%	1977	6.3	4.6	2,123
	5	517	OK	tangential	Subbit.	10652	51%	1978	4.6	3.6	2,171

Case Study 12. Brunner Island, Pennsylvania

PPL Brunner Island is a large (over 1400 MW) scrubbed facility with three units shown in Figure 20. As a scrubbed plant, Brunner Island is unique among the facilities. According to the National Electric Energy Data System (NEEDS), the scrubbers went on line in 2008 and 2009. So, they are modern wet FGD systems.

On September 27, 2014 the Pennsylvania Department of Environmental Protection announced that it plans to issue an air permit change allowing gas firing at PPL Brunner Island. The permit will allow "for the addition of natural gas as a fuel firing option for the three existing utility boilers (Source IDs 031A, 032 and 033A) and their associated coal mill heaters that will involve the tying in of a natural gas pipeline (Source ID 301), as well as the construction of two natural gas-fired pipeline heaters (Source ID 050) at the Brunner Island Steam Electric Station in East Manchester Township, York County."[66]

Figure 20. Brunner Island Power Plant

[66] http://www.power-eng.com/articles/2014/09/ppl-permits-gas-firing-at-big-brunner-island-coal-plant.html

The project has not yet been decided for certain. According to PPL spokesman George Lewis, PPL is still in the process of exploring gas co-firing as an option for the Brunner Island plant. "It's important to note that a decision has not been made on whether to go ahead with the project,"[67] Because the project is at an early stage, cost information is not yet available.

The plant, located southeast of Harrisburg, PA, is less than ten miles from an interstate pipeline, as shown in Figure 21.

Figure 21. Location of Brunner Island Power Plant (black circle with white triangle) and interstate natural gas pipeline (blue lines), source: EIA

It may be of note that, although Brunner Island is scrubbed, it is not equipped with SCR for NOx control. As such, gas cofiring would provide Brunner Island additional flexibility in reducing NOx emissions further and be an option that might help PPL avoid installation of SCR for NOx control at Brunner Island in the event that the reinstated Cross State Air Pollution Rule imposes more stringent NOx emission requirements on the plant in the future. It would also provide them additional flexibility to mitigate CO_2 emissions. Other considerations are that the location, in central Pennsylvania, situates it well in relation to Marcellus shale gas.

[67] http://generationhub.com/2014/09/29/ppl-permits-gas-firing-at-big-brunner-island-coal

Table 17 shows data on Brunner Island, including 2013 emission rates and capacity factor. Brunner Island is significant in the fact that it is scrubbed and has some fairly large units – one over 700 MW. The 2013 capacity factors in the range of 50% are significantly lower than they were in 2009 when capacity factors were above 70% for all three units. This drop in capacity factor is likely the result of the drop in natural gas prices during that time. Brunner Island power plant is located just to the east of the Marcellus shale gas sources.

Table 17. Information on Brunner Island, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Brunner Island	1	312	PA	tang	Bit	10023	58%	1961	3.2	3.5	1,884
	2	371	PA	tang	Bit	9695	50%	1965	3.6	3.3	1,858
	3	744	PA	tang	Bit	9502	55%	1969	3.3	3.3	1,827

Cast Study 13 New Castle, Pennsylvania

NRG Energy announced that they will be converting New Castle power plant to natural gas. The facility, shown in Figure 22, has three units ranging from 93 to 132 MW in size and was destined to be shut down by April 2015 until NRG Energy announced in June 2013 that they would convert the plant to natural gas by May 2016.[68]. The conversion is scheduled to be completed in 2016 and will likely operate as a peaking unit. In September 2014, Pennsylvania Department of Environmental Protection announced its plans to issue a permit for the gas conversion, which would include the addition of gas burners to the boilers.[69]

Figure 22. New Castle Power Plant

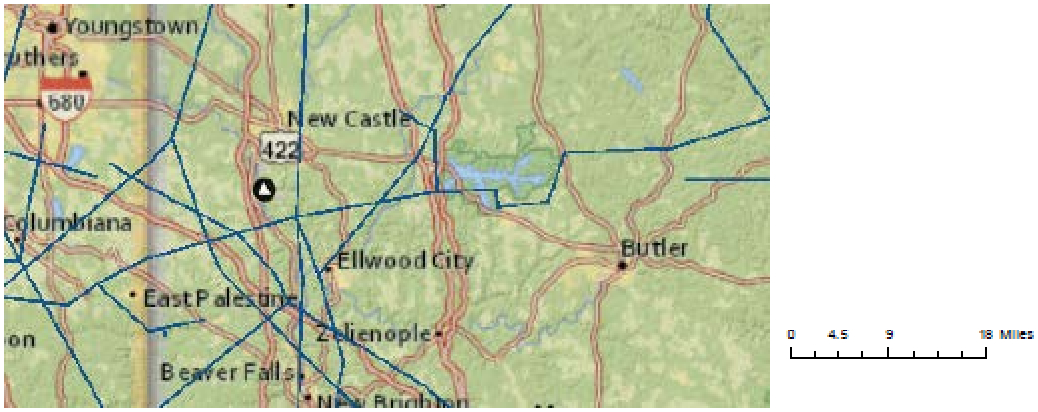
New Castle power plant is located in the middle of the Marcellus shale gas region of western Pennsylvania and is only a few miles from an interstate natural gas pipeline. The plant did not previously burn natural gas. Therefore, a natural gas pipeline will need to be built to connect the plant to the interstate pipeline, shown in Figure 23.

---

[68] http://www.post-gazette.com/local/region/2013/06/24/New-Castle-power-plant-switching-to-natural-gas/stories/201306240188

[69] http://www.power-eng.com/articles/2014/09/nrg-nears-permit-for-coal-to-gas-conversion-at-new-castle.html

Figure 23. New Castle Power Plant (black circle with white triangle) and interstate natural gas pipelines (blue lines), source: EIA



Data on the New Castle Plant is shown in Table 18, including emission rates and capacity factor. The units are only in the 100 MW range and will likely be operated as peaking units in the future. Capacity factors dropped off by about half between 2009 and 2013, likely due to reduced natural gas prices.

Table 18. Information on New Castle Power Plant, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh		
									2013 SO2	2013 NOx	2013 CO2
New Castle	3	93	PA	wall	Bit	11265	12%	1952	25.1	4.0	2,149
	4	95	PA	wall	Bit	11028	15%	1958	23.2	3.4	2,007
	5	132	PA	wall	Bit	10846	15%	1964	26.0	4.7	2,189

Case Study 14. Clinch River Power Plant, Virginia

Appalachian Power, part of AEP, has decided to retire one of the Clinch River units in Russell County, VA, and will convert the other two to natural gas. Clinch River Plant is shown in Figure 24. One Clinch River unit will be switched to gas in September 2015, the other in February 2016. A third 240-MW coal unit was planned for shutdown in 2014. The two remaining 230 MW units will be operating on 100% natural gas starting spring of 2016, in time to avoid retrofitting equipment for compliance with MATS. The total cost of the project, including pipeline for natural gas, is estimated to be $56 million, or $107/kW, well below the cost of a new combined cycle plant or combustion turbine. The impact to the average residential customer is estimated at less than fifty cents a month.[70] Information was not available on how much of the cost was related to the pipeline versus the boiler modifications.

Figure 24. The Clinch River Power Plant

[70] http://www.tricities.com/workittricities/business_news/article_44610142-bf81-11e3-9eae-0017a43b2370.html
http://www.platts.com/latest-news/coal/louisvillekentucky/aeps-clinch-river-power-plant-in-virginia-to-21100599

Clinch River was once one of the world's most efficient power plants. In 1960 it was the first power plant to operate with a heat rate below 9,000 Btu/kWh for a full calendar year. For the conversion it was necessary to add natural gas pipeline. Approval was sought from Virginia and West Virginia regulators in spring of 2013. In April 2014 the pipeline contract had already been awarded and both units should be operating on gas in early 2016.[70] As shown in Figure 25, Clinch River is located under ten miles from the nearest interstate pipeline.

Figure 25. Clinch River Power Plant (black circle with white triangle) and interstate natural gas pipelines (blue line)
Source: Energy Information Administration

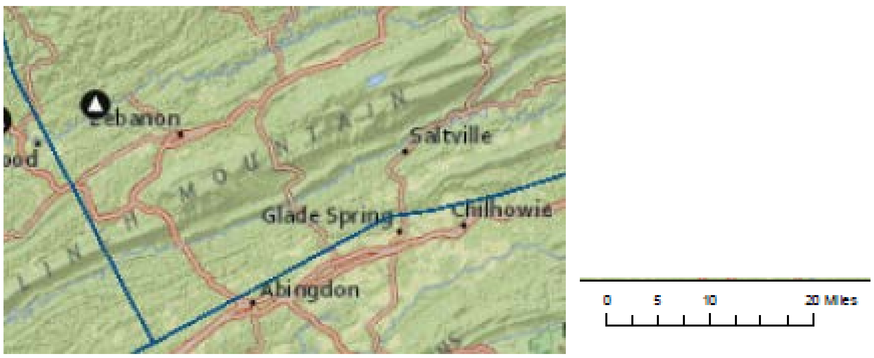


Table 19 shows data on Clinch River Power Plant, including 2013 emission rates and estimated capacity factor. As shown, the units had been operating in 2013 more or less as cycling or peaking units.

Table 19. Information on Clinch River units 1-3 to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
	1	230	VA	vertical	Bit.	10227	21%	1958	7.8	2.1	2,027
Clinch River	2	230	VA	vertical	Bit.	10179	14%	1958	8.0	2.1	2,050
	3	230	VA	vertical	Bit.	10179	14%	1958	8.4	1.8	2,099

Case Study 15. Blount Street, Wisconsin

Blount Street Station, shown in Figure 26, is in Madison, WI and has two roughly 50 MW units. With demand for electricity from the plant greatly reduced, in 2010 Madison Gas & Electric converted the plant to natural gas. The two boilers operate only as peaking units now.

Figure 26. Blount Street Station

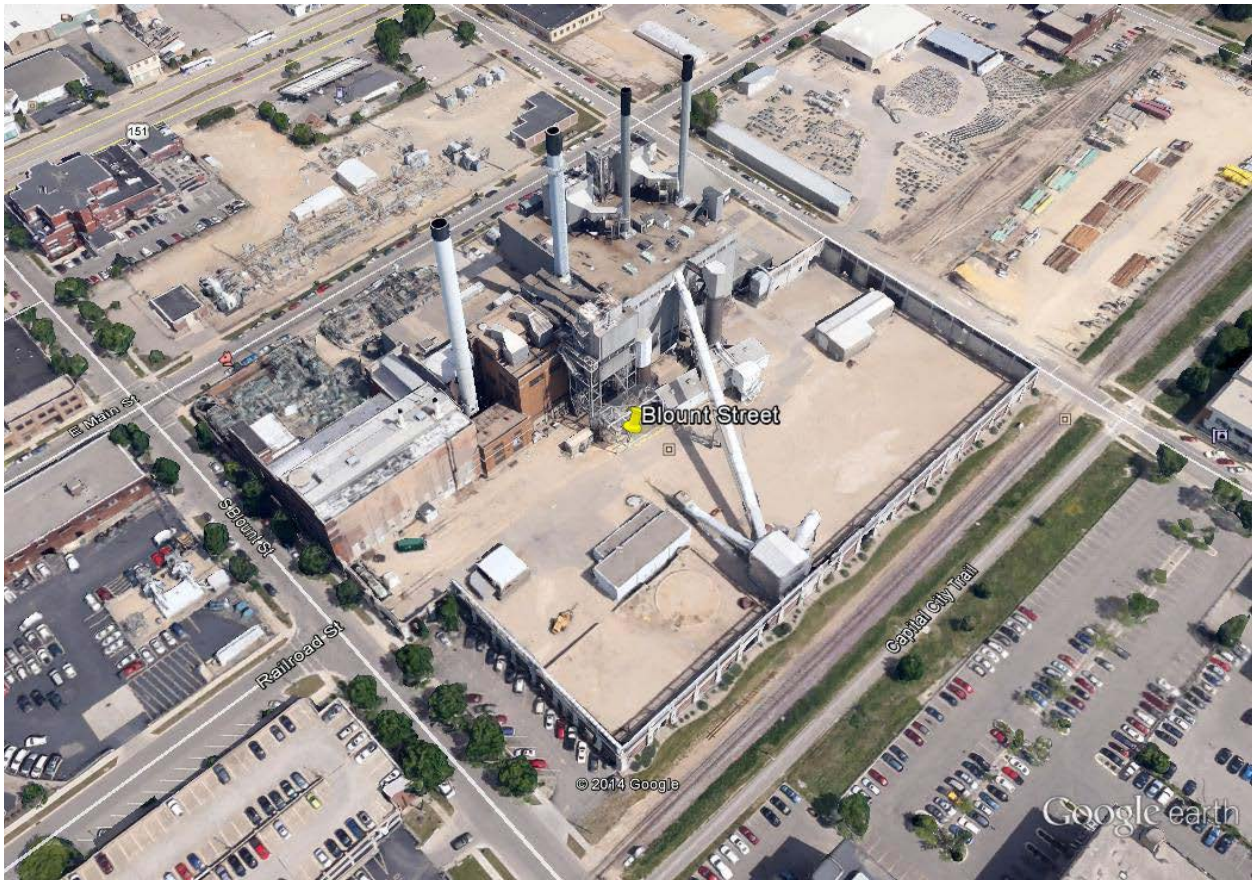


Table 20 shows data on Blount Street Station, to include 2009 and 2013 emission rates. As shown, emission rates dropped significantly, 100% for SO_2, about 45% for NOx and about 28-33% for CO_2. As noted, the units are only operated for peaking use.

Table 20. Information on Blount Street units 8 & 9 to include 2009 and 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	Heat Rate	Yr in Srvc	2009 Cap. Fctr	2013 Cap. Fctr	2009 lb/MWh			2013 lb/MWh		
										SO2	NOx	CO2	SO2	NOx	CO2
Blount Street	8	51	WI	wall	Bit.	14500	1957	4%	2%	25.8	4.2	2,479	0.0	2.3	1,794
	9	50	WI	wall	Bit.	14278	1961	3%	2%	25.8	4.3	2,401	0.0	2.5	1,608

Case Study 16. Valley units 1-4, Wisconsin

Valley units 1-4, shown in Figure 27, supplies electricity to the grid and steam to nearby customers in downtown Milwaukee. Conversion of each of the four 67 MW units will be completed in 2015 and 2016, thereby avoiding the retrofit of equipment for MATS compliance. The total cost of the project is $62 million for the plant modifications and $4.25 million to install 1,800 feet of high pressure natural gas supply and regulation equipment.[71] This equates to a total cost of $247/kW. The relatively high cost of the boiler retrofit is a result of the small size (67 MW each) and the extensive modifications to the boiler and steam supply system that included:

- Removing the coal burners and associated coal piping from the existing four boilers;
- De-energizing and decommissioning coal conveyors, coal silos, coal mills, coal feeders, the bottom ash removal system, and the fly ash removal system;
- Installing new natural gas burners in each of the four boilers;
- Installing a natural gas header and associated valves to supply fuel to the new gas burners;
- Installing new flue gas recirculation (FGR) fans and associated ductwork and electrical work for use in the control of emissions from the boilers;
- Sealing each boiler after removal of existing burners, soot blowers, and bottom seal equipment;
- Installing boiler let-down valves to reliably support steam supply to the district heating system under single steam turbine operation; and
- Updating the control system to integrate new equipment into Valley's distributed control system.

The $62 million cost is broken down into:

- Structures and improvements $9,000,000
- Boiler plant equipment 46,200,000
- Accessory electric equipment 5,600,000
- Miscellaneous power plant equipment 1,200,000
- Total $62,000,000

Table 21 shows data on Valley Station to include 2013 emission rates (expressed in lb/MMBtu because generation data was not available in the Title IV data). As shown, the capacity factors of the units in 2013 were in the range of 22% to 31%, meaning that these units served more as cycling units. The heat rate for Valley is high because Valley produces both power and heating steam. The plant fixed and variable operating costs will be reduced.

[71] PUBLIC SERVICE COMMISSION OF WISCONSIN, Final Decision, Application of Wisconsin Electric Power Company for Authority to Convert the Valley Power Plant from a Coal-Fired Cogeneration Facility to a Natural Gas-Fired Cogeneration Facility, March 17, 2014

Figure 27. Valley Station

Table 21. Information on Valley units 1-4, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MMBtu 2013 SO2	2013 NOx	2013 CO2
Valley	1	67	WI	wall	Bit.	14500	31%	1968	0.7	0.2	205
	2	67	WI	wall	Bit.	14500	30%	1968	0.7	0.2	205
	3	67	WI	wall	Bit.	14500	22%	1969	0.7	0.2	205
	4	67	WI	wall	Bit.	14500	27%	1969	0.7	0.2	205

.

Case Study 17. Naughton Unit 3, Wyoming

The Naughton unit 3 in Wyoming is a 330 MW BART-affected unit that burns Powder River Basin coal and is shown in Figure 28. Pacificorp, the owners, elected to convert the unit to natural gas for compliance with the Regional Haze Rule. Although base-loaded, Naughton plant is located adjacent to gas pipelines and has access to natural gas. March 4, 2014 comments from the Oregon PUC indicates a conversion date in 2018. This document also indicates that Oregon PUC staff would like Pacificorp to further consider retirement as an alternative to conversion in their 2015 IRP.[72, 73] Cost information was not available in the IRP documentation.

Figure 28. Naughton Power Plant

Table 22 shows information on Naughton unit 3, including 2013 emission rates and estimated capacity factor based upon Title IV data and NEEDS v5.13 reported heat rate and MW output. As shown, Naughton 3 is a base loaded unit.

[72] PUBLIC UTILITY COMMISSION OF OREGON STAFF REPORT PUBLIC MEETING DATE: March 17, 2014; http://www.puc.state.or.us/meetings/pmemos/2014/031714/reg1-LC%2057.pdf

[73] BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON LC 57; "In the Matter of PACIFICORP, dba PACIFIC POWER ORDER; 2013 Integrated Resource Plan. DISPOSITION: 2013 IRP ACKNOWLEDGED WITH EXCEPTIONS AND REVISIONS JUL 0 8 2014

Table 22. Information on Naughton unit 3, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Naughton	3	330	WY	tangential	PRB	10,517	97%*	1971	3.5	2.7	2,029

* This capacity factor was estimated from Title IV reported generation and the nameplate capacity in NEEDSv5.13. Although it seems very high, Pacificorp assumed a 90% capacity factor in their 2007 BART analysis.[74] So, the Naughton unit 3 capacity factor was likely around 90% or better in 2013.

[74] See Appendix A of "Final Report BART Analysis for Naughton Unit 3 Prepared For: PacifiCorp" by CH2MHill, December 2007

Natural Gas Transmission Infrastructure Proximity to Coal Power Plants

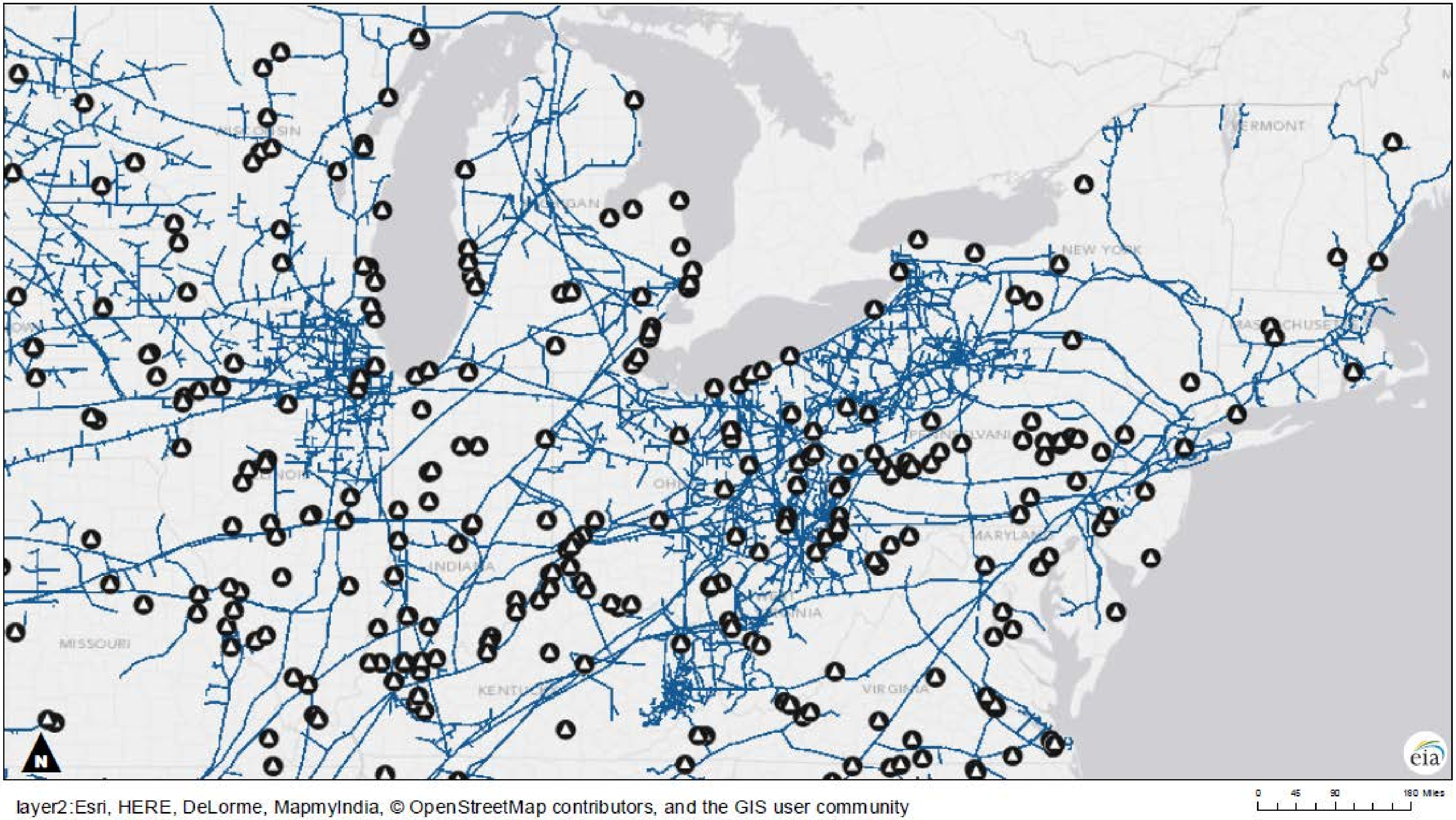
Natural Gas is available in most parts of the United States and, if not available on site, is often located someplace near an existing coal fired power plant. Figures 29 through 33 show the locations of coal-fired power plants (including some large coal-fired industrial plants, such as paper mills) in round black circles with white triangles and the location of interstate pipelines in blue lines. As shown, the vast majority of coal fired plants is located in the general vicinity of an interstate pipeline and, as such, could have access to natural gas. There are, however, a small number of power plants in fairly remote locations that would require longer pipelines to gain access to natural gas.

Figures 29-33 do not provide information on the need to enlarge or expand existing pipeline infrastructure to accommodate increased natural gas demand from the power sector. In their analysis, EPA attempted to incorporate this into their analysis, and this is perhaps why in some cases they concluded that some plants required extensive pipeline needs. For example, they determined that conversion would require 310 miles of pipeline for the Presque Isle Power Plant near Marquette, MI. On the other hand, as shown in Figure 34, the Presque Isle Power Plant is only a few miles from an interstate pipeline. So, making the connection to the interstate pipeline could not possibly explain the length of pipeline estimated by EPA. It is likely that this is what EPA has estimated is needed to enlarge the existing interstate pipeline infrastructure. But, it is also may be that these assumptions are conservative, as demonstrated by EPA's analysis of Edge Moor plant in Delaware. EPA estimated that 24.7 miles of pipeline must be constructed for Edge Moor 3; however, Edge Moor 3 has already been converted to natural gas.

In any event, the existence of this infrastructure does eliminate one of the major hurdles to expansion of infrastructure along these routes where pipelines already exist– the need to gain rights of way.

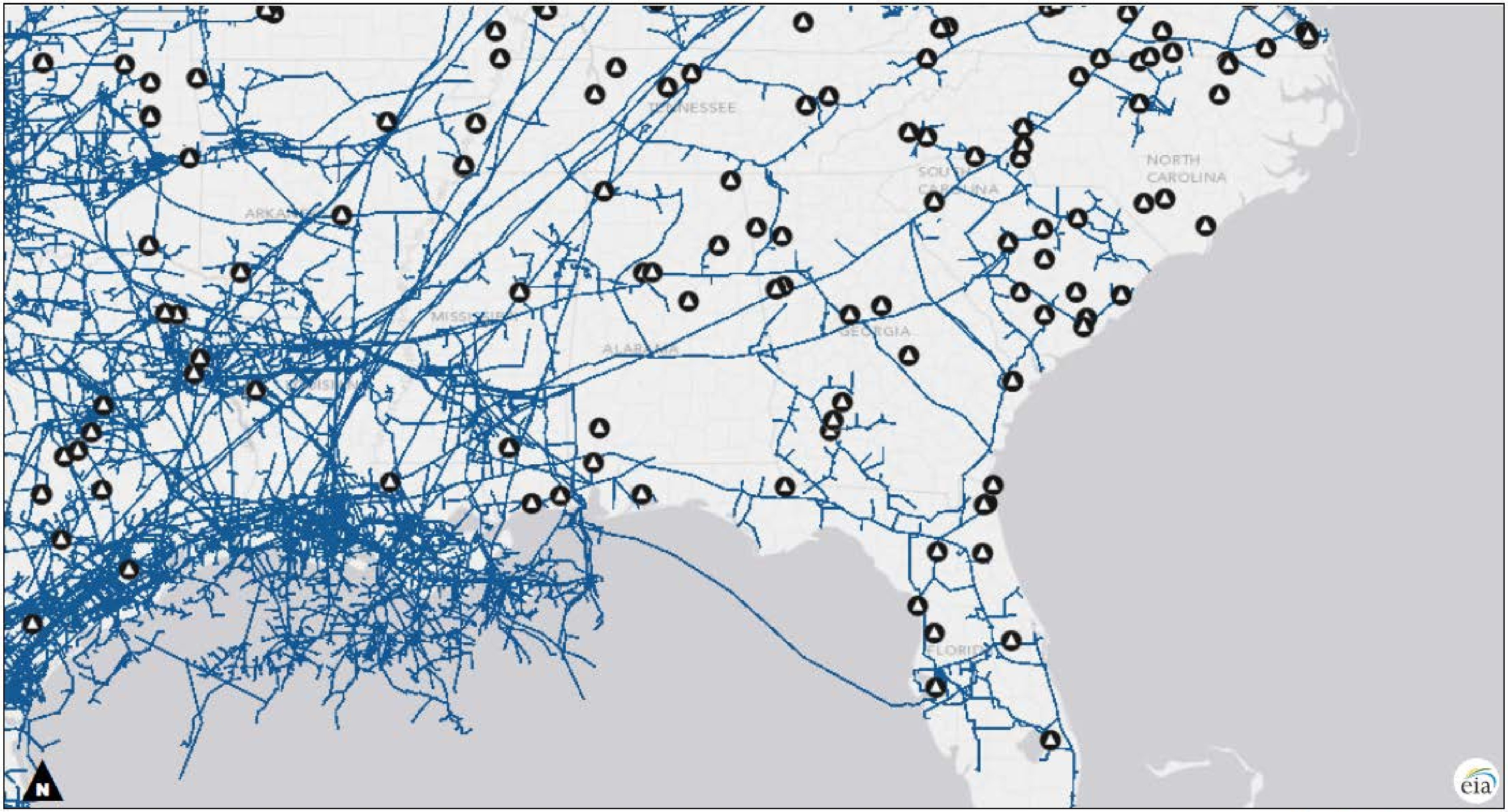
Another factor that has played into the conversion of many coal fired power plants is the increased availability of natural gas from shale gas, and especially from the Marcellus region that spans from upstate New York through Pennsylvania, Ohio and West Virginia. This formation, shown in Figure 35, has had a steady increase in natural gas production from about 2 million cubic feet per day in 2010 to about 16 million cubic feet per day today, as shown in Figure 36.

Figure 29. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Northeast United States. Source: Energy Information Administration



layer2:Esri, HERE, DeLorme, MapmyIndia, © OpenStreetMap contributors, and the GIS user community

Figure 30. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Southeast United States. Source: Energy Information Administration



layer2:Esri, HERE, DeLorme, MapmyIndia, © OpenStreetMap contributors, and the GIS user community

Figure 31. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Upper Great Plains United States. Source: Energy Information Administration

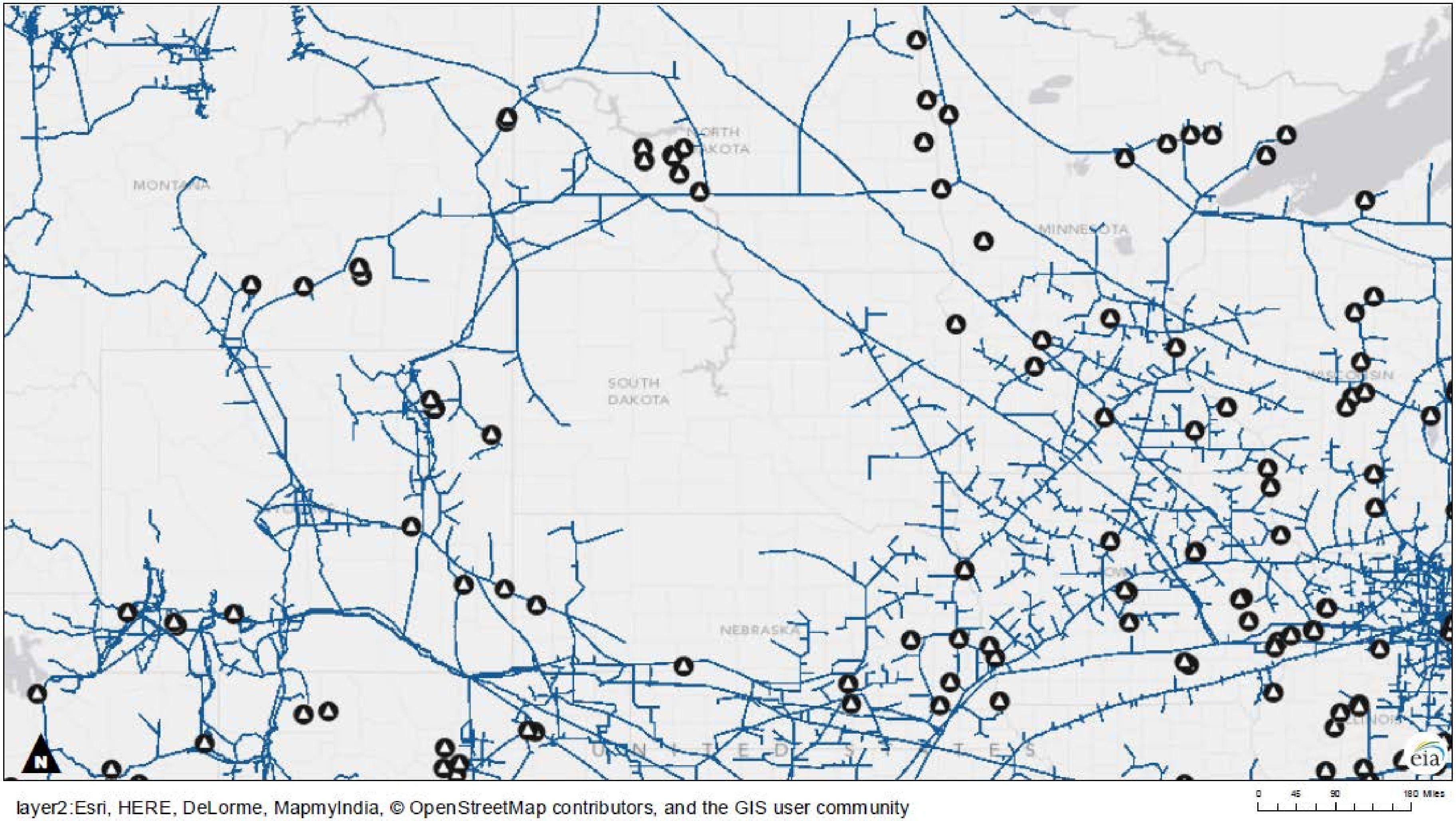
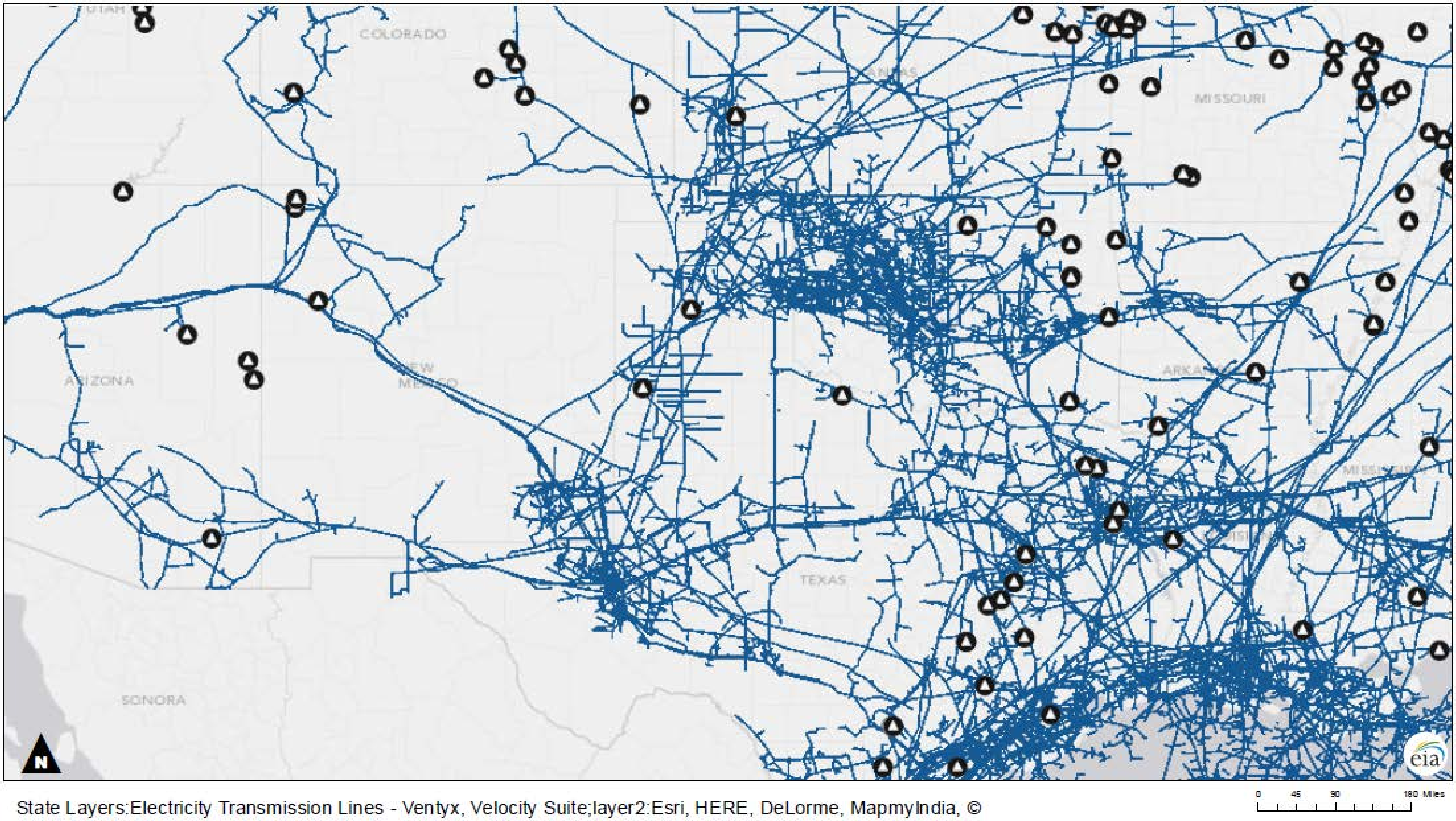
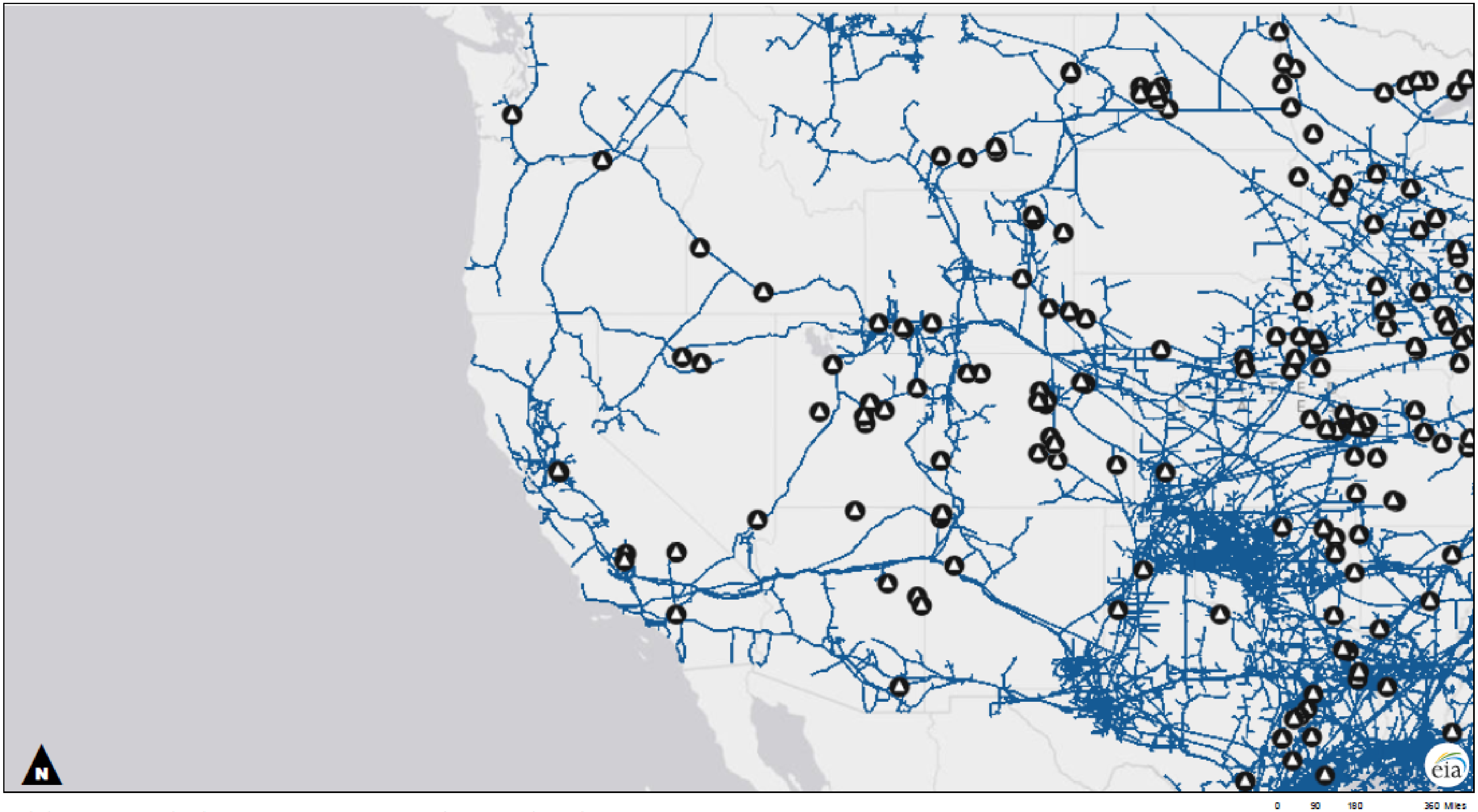


Figure 32. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Lower Great Plains United States. Source: Energy Information Administration



State Layers:Electricity Transmission Lines - Ventyx, Velocity Suite;layer2:Esri, HERE, DeLorme, MapmyIndia, ©

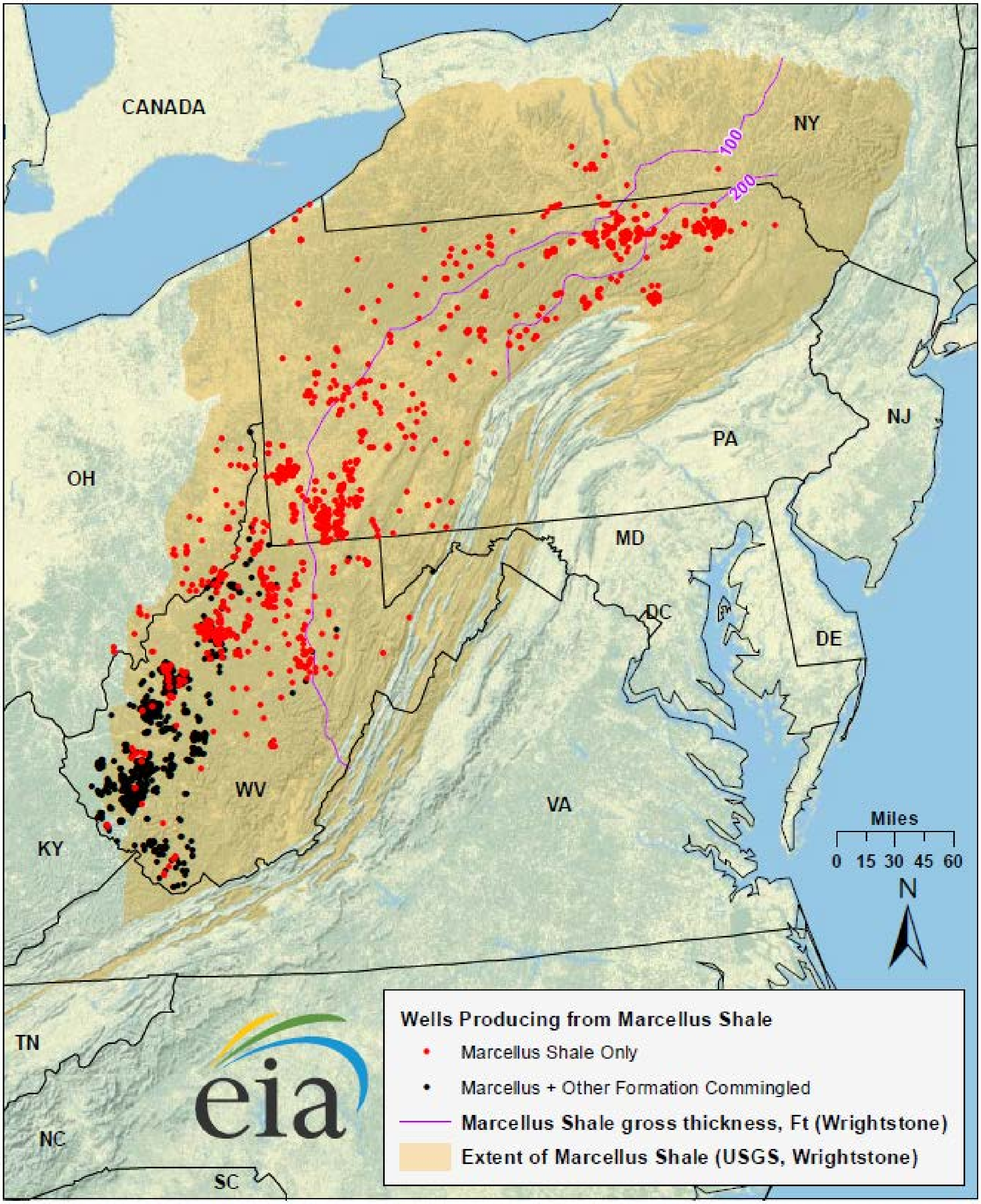
Figure 33. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Upper Western United States. Source: Energy Information Administration



State Layers:Electricity Transmission Lines - Ventyx, Velocity Suite;layer2:Esri, HERE, DeLorme, MapmyIndia, ©

Figure 34. Presque Isle Power Plant (black circle with white triangle above Marquette, MI), and Interstate Gas Pipelines (blue lines), map is from EIA

Figure 35. The Marcellus Shale Gas Play, Appalachian Basin (EIA)



Source: US Energy Information Administration based on data from WVGES, PA DCNR, OH DGS, NY DEC, VA DMME, USGS, Wrightstone (2009). Only wells completed after 1-1-2003 are shown. Updated June 1, 2011

Figure 36. Marcellus Region Natural Gas Production (source: EIA)