2012

Potential Impacts of Replacing Retiring Coal in MISO with Natural Gas & Wind Capacity

NARUC Grants & Research

NARUC

September 2012

The National Association of Regulatory Utility Commissioners

A report for the Iowa Utilities Board
Funded by the U.S. Department of Energy

The report you are reading was created under the State Electricity Regulators Capacity Assistance and Training (SERCAT) program, a project of the National Association of Regulatory Utility Commissioners (NARUC) Grants & Research Department. This material is based upon work supported by the Department of Energy under Award Number DE-OE0000123.

The report was authored by Synapse Energy Economics, INC. Throughout the preparation process, the members of NARUC provided the author(s) with editorial comments and suggestions. However, the views and opinions expressed herein are strictly those of the author(s) and may not necessarily agree with positions of NARUC or those of the U.S. Department of Energy.

Special thanks to the Commissioners and staff at the Iowa Utilities Board for guiding this work, and to the Office of Electricity Delivery and Energy Reliability and the National Energy Technology Lab for their continued technical assistance to NARUC.

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Synapse
Energy Economics, Inc.

Potential Impacts of Replacing Retiring Coal Capacity in the Midwest Independent System Operator (MISO) Region with Natural Gas or Wind Capacity

Prepared for the Iowa Utilities Board (IUB)
September 14, 2012

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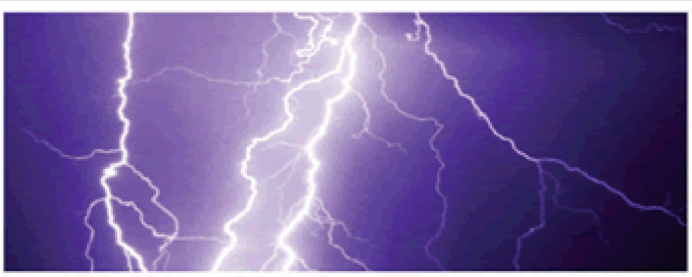

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1. Introduction

Throughout the United States existing coal-fired generating units face the need to comply with a number of tighter and new federal emission standards expected to take effect between 2015 and 2020. It is generally expected that plant operators will decide to retire a number of older, smaller units rather than to invest in the new emission controls required to comply with these emission standards.

Existing coal-fired generating units located in the region covered by the Midwest Independent System Operator (MISO) are facing the same federal standards.[1] The Iowa Utilities Board (IUB), via funding from the National Association of Regulatory Utility Commissioners (NARUC), retained Synapse Energy Economics (Synapse) to help them analyze the factors that will affect the choice of capacity to replace coal-fired capacity located in the MISO region that is likely to retire by 2020.

This report summarizes the findings from our high-level analyses of key potential impacts on the region's wholesale electric and natural gas markets in 2020. It presents findings for three possible cases of coal capacity retirements and mixes of replacement capacity—a base case, a high gas-fired capacity case ('high gas case'), and an additional wind capacity case ('additional wind case') which includes sensitivities for varying quantities of wind additions. Attachment A provides the key assumptions used in the report. Attachment B provides detailed results from the assessment of potential wholesale electric market impacts in the MISO region and Attachment C provides detailed results from the assessment of potential wholesale gas market impacts in the MISO region.

This report provides a high level snapshot of potential impacts on the wholesale electric and natural gas markets in the MISO region for the year 2020 under a specific set of assumptions. Readers are cautioned not to extrapolate these results to individual states or individual utilities. While the study provides useful insight regarding potential impacts on these regional markets in general, the actual impacts will be driven by decisions at the individual utility level. The decisions by each individual utility will depend on a number of issues unique to that utility, including its location, existing resource mix, and assumptions regarding future environmental rules, compliance costs, and fuel costs.

2. Federal emission standards and compliance measures

This report assumes that fossil fuel units operating in 2020 will have to comply with six federal emission standards: the Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standards (MATS, Coal Combustion Residuals (CCR), Clean Water Act § 316(b)[2], Waste Water Rule, and Carbon Dioxide Emissions.

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[1] Within the U.S. this region consists of utility service areas located in Iowa, Indiana, Minnesota, Missouri, Montana, North Dakota, South Dakota, and portions of Illinois and Wisconsin.

[2] Also referred to as Cooling Water Intake Standard (CWIS).

Our analyses assumed that the CSAPR and MATS standards would be in effect in 2015. However, the effective date of CSAPR is now unknown. On August 21, 2012 the United States Court of Appeals for the District of Columbia issued a decision vacating CSAPR. Depending on the outcome of the anticipated appeals of that decision the same rule, or a replacement rule requiring the same reductions, may go into effect sometime between 2016 and 2019. We believe our projections for 2020 are still relevant since many utilities that had decided to invest in retrofits have already begun to make those capital expenditures and because units that were planning on retiring will likely continue to operate until the MATS deadline.

The report assumes the other four standards will be in effect by 2020, i.e., Coal Combustion Residuals (CCR), Clean Water Act § 316(b)[3], Waste Water Rule, and Carbon Dioxide Emissions. While there is considerable uncertainty regarding the timing and design of future federal regulation of carbon emissions, Synapse considers it reasonable to assume that generating units in MISO would be subject to federal regulation of carbon emissions beginning in 2020.

The new environmental control measures existing coal units will have to implement in order to comply with these federal emission standards will vary from unit to unit according to the standard, the existing measures in place at the unit, and the size of the unit. The potential compliance measures required to comply with each rule are summarized in Table 1.

Table 1. Federal Emission Standards and Potential Compliance Measures

Rule	Potential Compliance Measures
Cross-State Air Pollution Rule (CSAPR)	Wet flue gas desulfurization (FGD), low NOx burners, selective catalytic reduction (SCR), dry sorbent injection (DSI)
Mercury and Air Toxics Standards (MATS)	FGD, bag house, activated carbon injection (ACI)
Coal Combustion Residuals (CCR)	Coal ash disposal
Clean Water Act § 316(b)	Recirculating cooling
Waste Water Rule	Wastewater treatment
Carbon Dioxide Emissions	Compliance payment

The cost impacts of those new measures will also vary from unit to unit according to the specific measures that are implemented. The major cost impacts of installing the potential measures required to comply with the first five rules are incremental capital costs, although several of the measures also cause incremental variable operating and maintenance (VOM) costs. The major cost impact of complying with the carbon dioxide emissions standard would be an increase in VOM costs.

[3] Also referred to as Cooling Water Intake Standard (CWIS).

3. Coal unit retrofits and retirements

Our analysis identified 241 existing conventional coal units located in MISO, representing 59.7 GW of existing capacity, which would have to comply with the tighter and new emission standards. Our review identified an additional 70 GW of other capacity existing as of 2011 that would not incur material capital costs in order to comply with the new and tighter standards.[4]

Estimating which of the 241 existing conventional coal units are most likely to invest in new emission controls (i.e., likely to retrofit), and which are likely to retire rather than make those investments is a complex exercise that rests upon numerous assumptions.

Many analysts develop these estimates using an economic screening model to compare the cost of retrofitting each existing coal unit to an alternative source of comparable replacement capacity and energy. These estimates commonly assume the alternative resource would be a gas-fired combined cycle (CC) unit. Their economic models project the incremental, or going-forward, costs that each existing unit would incur to make the necessary retrofits, as well as the incremental costs of obtaining a comparable quantity of capacity and generation from gas-fired units. If the projected incremental cost of retrofitting the existing coal unit is less than the total going-forward cost of comparable capacity and generation from gas-fired units, the economic decision is to retrofit the unit. If the incremental cost of the retrofit is higher than the total going-forward cost of comparable capacity and generation from gas-fired units, the economic decision is to retire the unit.

In order to project the incremental costs a specific existing unit would incur to make the retrofits, analysts need several key pieces of information or assumptions about that specific coal unit. These include:

- The unit's existing emission controls and key operating characteristics such as heat rate, capacity factor, and non-fuel variable operating and maintenance (VOM) costs;
- The additional or new emission controls the unit would require to comply with the tighter and new emission regulations;
- The incremental capital and operating costs the unit would incur if it added those new emission controls; and
- The projected price of coal delivered to the unit.

Analysts also require considerable data and assumptions about the alternative resource in order to project the going-forward capital and annual operating costs of obtaining a comparable quantity of capacity and generation. The information and assumptions include:

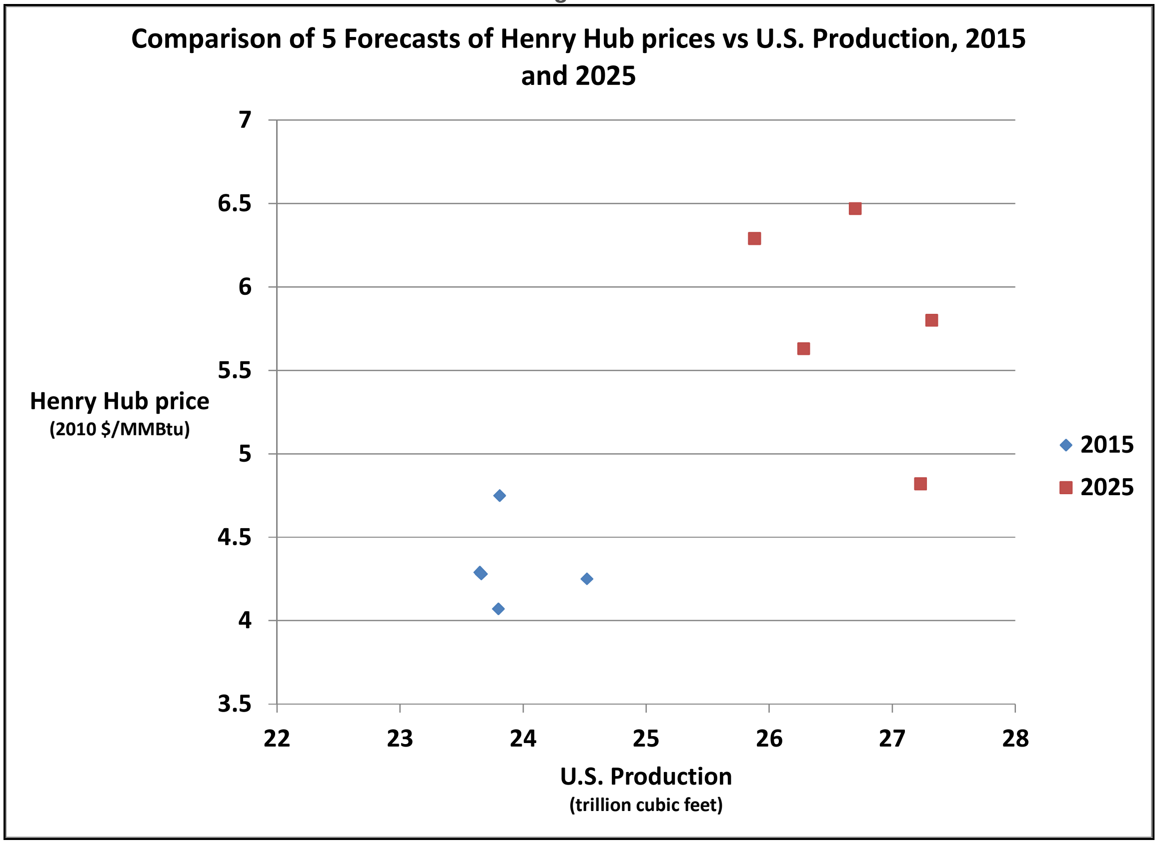
[4] 11.7 GW of the 70 GW of other capacity is coal-fired units that are either cogenerators or units for which we did not have data because they have not been in standard operation in recent years. Given the difficulty of estimating environmental control costs for these units our study excluded them in order to be conservative.

- The quantity and location of existing gas-fired capacity, both combined cycle (CC) and combustion turbines (CT), and the key operating characteristics of that capacity such as heat rate, capacity factor, and non-fuel VOM costs;
- The incremental costs of building and operating new gas fired CC and CT units;
- The projected price of well-head gas supply; and
- The incremental cost of delivering incremental quantities of natural gas to gas-fired generating units.

Given the number of existing coal-fired units in MISO, the number of assumptions underlying estimates of the future economics of retrofitting each of those units, and the uncertainty regarding several of those key assumptions, it is not surprising that there is a range of estimates for the number and capacity of conventional coal units that are likely to be retrofitted.

The future price of natural gas supply production, as reported at the Henry Hub, is a key assumption in these evaluations and there is considerable uncertainty associated with that assumption. Forecasting natural gas production prices has proven to be very difficult over the years. As indicated in Figure 1, there are a range of forecasts of Henry Hub prices and national production for 2015, and the range of those forecasts increases as one goes further out in time to 2025. The five forecasts plotted in Figure 1, from the Energy Information Administration (EIA) Annual Energy Outlook 2012 (AEO 2012), were prepared by the EIA, IHSGlobal Insight, Energy Ventures Analysis, Deloitte LLP, and Strategic Energy and Economic Research respectively.

Figure 1



Our report analyzes projections of the capacity of existing coal units likely to be retrofit, and the capacity likely to be retired. These projections are drawn primarily from an evaluation prepared by MISO in October 2011.[5] We decided to base our projections on the results of the MISO report after reviewing the results of our economic screening analyses and the results of other published projections of the impact of new Environmental Protection Agency (EPA) regulations on existing coal units.[6] [7] [8] The MISO study is based upon very detailed and extensive modeling which has been subject to industry review.

Based on this review of economic screening results, our report groups the conventional coal units operating in the MISO region in 2011 (59.7 GW) into the following three tiers:

- **Tier I:** Units that would be retrofitted and continue to operate - 47.6 GW (80%),
- **Tier II:** Units that may or may not be retrofitted - 9.2 GW (15%), and
- **Tier III:** Units most likely to be retired - 2.9 GW (5%).

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[5] ___. *EPA Impact Analysis. MISO. October 2011.*
[6] ___ *AEO 2012,* EIA, June 2012.
[7] ___, *Coal Capacity at Risk for Retirement,* PJM, January 2012.
[8] ___, EIPC Results, BAU Scenario, Stakeholder Report F1S17, November 2011.

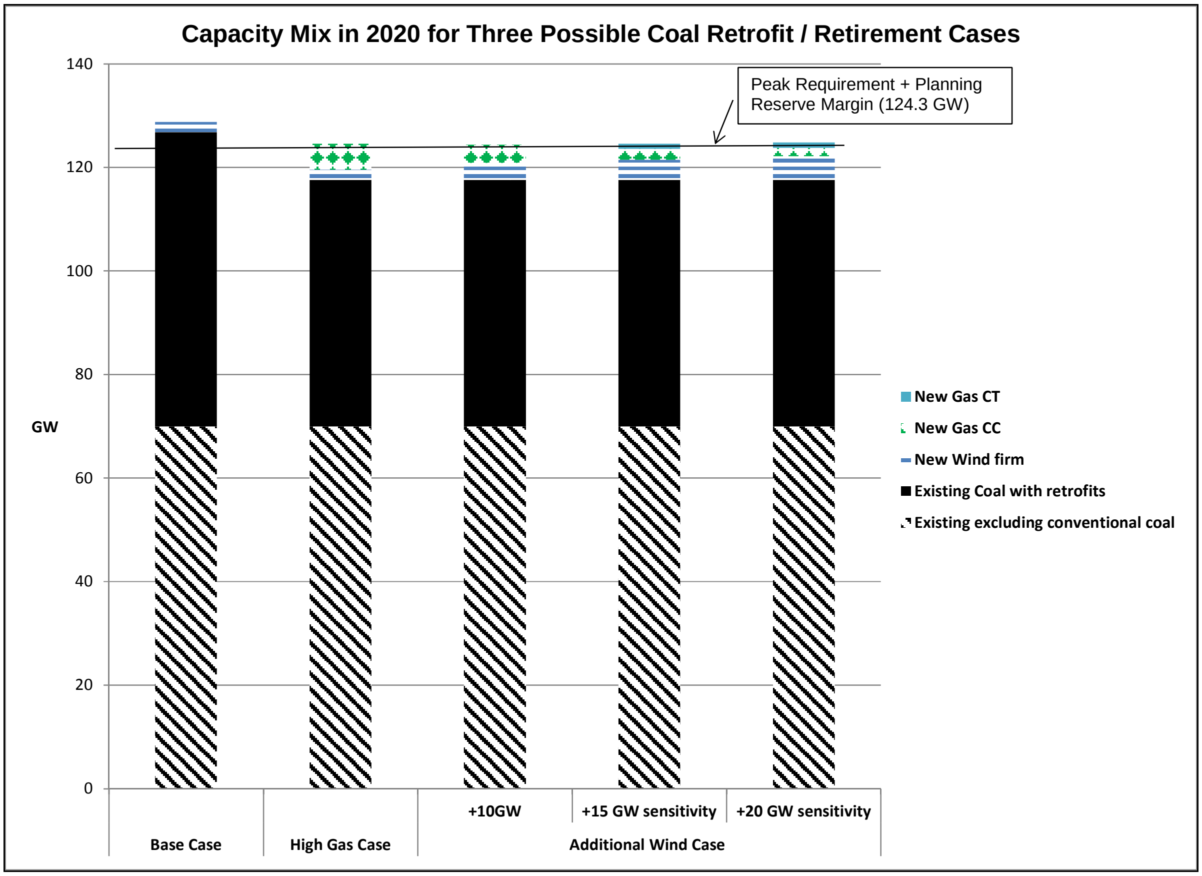
4. Coal Retrofit and Replacement Capacity Cases

The report presents high-level estimates of key potential impacts on the region's electric and natural gas markets in 2020 for three possible cases of coal retrofit capacity and mixes of replacement capacity. The three cases are — a base case, a high gas case, and an additional wind case which includes two additional sensitivities for wind additions of 15 GW and 20 GW, respectively.

Figure 2 illustrates the total firm capacity that would be required to ensure reliable service in 2020 (i.e., to meet the projected peak requirement plus the Planning Reserve Margin), and the mix of coal and other capacity assumed in each of the cases.

- The base case assumes Tier I and Tier II coal-fired capacity would be retrofitted, for a total of 56.8 GW. It does not assume any other new capacity additions since total firm capacity exceeds the peak requirement plus PRM.
- The high gas case assumes that the 47.6 GW of Tier I coal capacity would be retrofitted and that the 9.2 GW of Tier II capacity would be retired. This case assumes 5 GW of new gas CC capacity would be added to meet the PRM.
- The additional wind case also assumes the Tier I capacity would be retrofitted and the Tier II capacity would be retired. It assumes that a further 10 GW of wind capacity would be added, beyond the 15.4 GW added to meet the RPS, for a total of 25.4 GW of new wind capacity. That addition reduces the additional quantity of new gas CC required to meet the PRM to 3.5 GW.
- The two additional wind case sensitivity analyses assume additional increments of 15 GW and 20 GW of wind capacity, respectively. These two increments are each measured relative to the base case and are in addition to the 15.4 GW added to meet the RPS. They result in totals of 30.4 GW and 35.4 GW of new wind capacity, respectively. Under each of these two sensitivities, less new gas capacity in total is required to meet the PRM, but the mix of new gas capacity is different. The two sensitivities assume additions of new gas CC capacity of 2.1 GW and 1.6 GW respectively, as well as the addition of 1 GW of gas-fired CT under each sensitivity.

Figure 2



The key assumptions regarding firm requirements and sources of capacity in 2020 common to the three cases in 2020 are summarized below.

- Approximately 124.3 GW of firm capacity would be required to meet the Planning Reserve Margin (PRM), which is assumed to be 19%.
- The total firm capacity in each case would meet, or exceed, the PRM.
- Approximately 70 GW of other capacity existing as of 2011 would continue to operate.
- Out of the 59.7 GW of coal-fired capacity facing material costs to comply with the new emissions standards, 2.9 GW of coal-fired capacity would be retired.
- Generators would meet, or exceed, the Renewable Portfolio Standard (RPS) in MISO states projected to have such requirements in 2020 by adding at least 15.4 GW of new wind capacity. [9]
- Wind units would be credited for firm capacity equivalent to 12.9% of their installed or nameplate capacity.[10]
- Wind units do not receive a Production Tax Credit.

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[9] See Appendix Table A-6. Synapse estimated RPS requirements in 2020 by state based on data from the Database of State Incentives for renewables and efficiency (www.DSIREusa.org) and 2010 sales from EIA Form 861-File2.

[10] ___. *Planning Year 2011 LOLE Study Report. MISO. Section 4.1.3. https://www.misoenergy.org/Library/Repository/Study/LOLE/2011%20LOLE%20Study%20Report.pdf*

5. Potential impacts on wholesale electric market in 2020

The major potential impacts of the retirement of coal units in MISO on the region's wholesale electricity market will depend on the number and capacity of units that will be retired, and on the new resources that are chosen to replace that retiring capacity. Our report assesses the implications of three possible cases of coal capacity retirements and mixes of replacement capacity. The assessment addresses the following questions:

- Under what circumstances could wind energy provide some firm capacity without the assistance of natural gas capacity or other generation support?
- What additional costs must typically be incurred to deliver electricity generated from wind?
- Would wholesale electricity costs and prices be materially different if generation from retiring coal capacity was replaced primarily with generation from natural gas capacity versus from wind capacity?

A. Under what circumstances could wind energy provide some firm capacity without the assistance of natural gas capacity or other generation support?

Our study assumes 15.4 GW to 25.4 GW of wind capacity could be added in MISO in 2020, and be credited with firm capacity, without the support of new natural gas or other generation capacity. That quantity of wind capacity could be added because existing capacity in MISO, including gas-fired CT capacity of 21.9 GW, would provide the necessary dispatch flexibility. As higher quantities of new wind capacity are added, such as 30.4 GW or 35.4 GW, our analysis assumes that that 1 GW of new gas-fired CT capacity would be required to supplement the existing capacity.

B. What additional costs must typically be incurred to deliver electricity generated from wind?

The additional costs typically incurred to deliver more wind energy into the grid are costs for incremental operating reserves and for incremental transmission.

Our cases do not include estimates for incremental costs for operating reserves, as we do not expect these to be material, and estimating those costs was beyond the scope of this study. The incremental costs of additional operating reserve levels will vary depending on the forecasting tools used by the system operator, the spatial diversity (and thus the temporal diversity of energy output) of the aggregate wind resources connected, and the general level of flexibility exhibited by the non-wind resources connected to the MISO grid.

Our cases do not include estimates for incremental transmission costs because it does not appear that adding 15.4 GW to 35.4 GW of new wind capacity by 2020 would cause material incremental costs relative to current MISO transmission investment plans. MISO's current transmission plans include sufficient transmission facilities to support the 15.4 GW of new wind capacity assumed in our base case and high gas case. The current transmission plans include $5.2 billion in total costs for 17 "multi-value project" (MVP) investments whose costs are spread across the entire MISO region, with completion generally slated for no later than 2020.[11] These projects are planned for multiple purposes, including (primarily) allowance of wind integration (roughly at RPS levels) onto the grid. Additional transmission investment (incremental to the MVP portfolio) is also planned for baseline reliability purposes, and the costs for these facilities will be allocated to benefiting consumers in the local regions of MISO. Additional transmission investment is also planned for interconnecting new generation, with costs borne by those generators.

The additional wind cases add 10 GW to 20 GW to the 15.4 GW in the base case. Our assumptions regarding the capital cost of that new wind capacity are sufficient to cover transmission interconnection costs for this incremental level of wind, which we assume would be borne by the wind unit developers. The extent of additional bulk transmission need (beyond that approved for the MVP portfolio) specifically to integrate the incremental wind capacity assumed in the Additional Wind case, i.e., 10 GW to 20 GW, is unclear, as is the extent to which such transmission would be built by 2020. Whether or not additional bulk transmission would be needed for this level of wind would depend on many factors, including: 1) the location of the additional wind, 2) its proximity to the existing (and MVP-reinforced) transmission system, 3) whether it connects as an energy resource or a firm network resource, and 4) other driving factors for transmission need, including peak load levels and the makeup and configuration of other supply resources. Finally, MISO projections of incremental costs for the MVP portfolio average roughly $1/MWh of load served in the MISO region.[12] This investment, while serving multiple purposes, nonetheless allowed for roughly an incremental 15 GW of wind to be integrated onto the system.[13] It would not be unreasonable to notionally consider an additional transmission cost roughly in that same range (i.e., $1/MWh of MISO load served) for the additional wind case. However, we note that it is very difficult to accurately impute such a cost because it is likely that the next increments of transmission might be sized to handle more than just an incremental 10 to 20 GW.[14]

C. How would wholesale electricity costs differ if generation from retiring coal capacity was replaced primarily with generation from natural gas capacity or from wind capacity?

One would expect wholesale electricity costs in 2020 to differ for different quantities of coal capacity retrofits and different mixes of capacity replacement. In order to estimate those differences for each of the three cases we focused on two key sets of costs in 2020 - wholesale

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[11] See MISO "Multi-Value Project Portfolio, Results and Analysis," January 12, 2012. Available at https://www.midwestiso.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MVP%20Portfolio%20Analysis%20Full%20Report.pdf.

[12] MISO MVP report, page 87, "Figure 10.3: Indicative usage rate for recommended MVP portfolio from 2012 to 2051."

[13] See MVP report page 48. This section of the MVP characterizes the amount of wind "enabled" by the MVP portfolio in terms of the level of wind curtailment that would otherwise be needed, but for this new transmission. Thus the report suggests that more than 12 GW of wind would otherwise be curtailed. We interpret this finding as indicating that 10 to 20 additional GW of wind could be added to the grid even without adding more transmission, but the amount of curtailed energy from the incremental wind resource would likely be greater in the absence of new transmission. The actual average annual energy curtailment level would depend on numerous factors and is beyond the scope of the analytical effort for this report.

[14] MISO 2011 Transmission Expansion Plan (MTEP 11) appendices A, B, and C include numerous transmission alternative projects to build out the 765 kV system to allow for dramatically increased levels of potential wind integration in the region. See https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=113909.

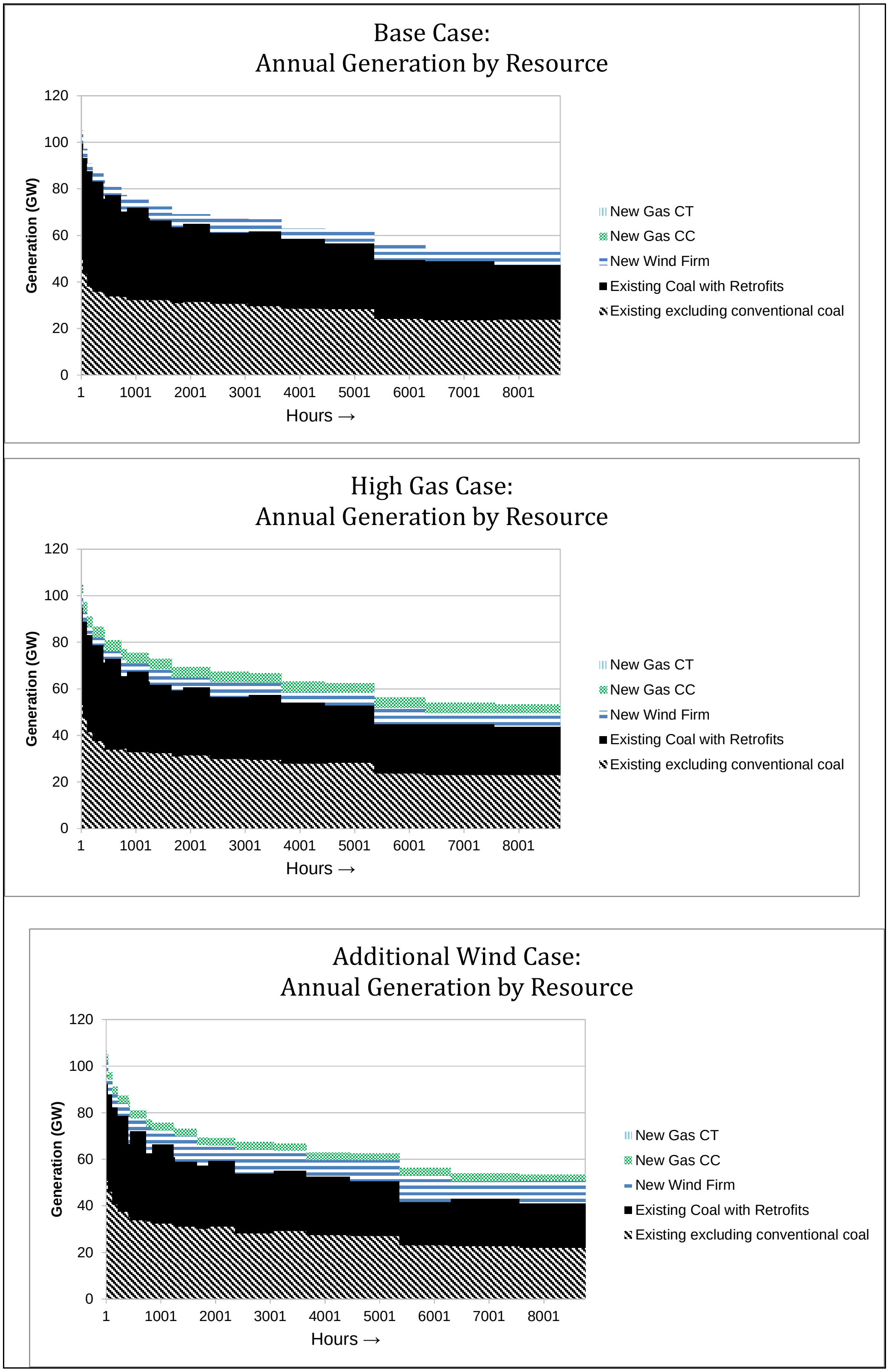
electric energy costs and the revenue requirements associated with incremental capital costs for environmental retrofits and capacity replacements. Wholesale electric energy costs are by far the larger of the two amounts.

Annual wholesale electric energy cost was calculated as the quantity of energy generated to supply load during each of the 20 blocks of hourly load used in our model multiplied by the energy cost of the marginal resource during each of those blocks. The revenue requirements in 2020 associated with incremental capital costs for environmental retrofits and capacity replacements represent the amounts plant owners would expect to collect in that year to recover depreciation of, and return on, those capital expenditures

We developed that projected energy mix, and the resulting annual average wholesale electric energy price under each case using a production costing model, the same basic approach MISO used in its October 2011 report.[15] However, our much simpler, spreadsheet production costing model simulated operation of the energy market in MISO in 2020 by dispatching capacity to supply 20 blocks of hourly load rather than dispatching capacity to meet load in each of the 8,760 hours of the year. Figure 3 provides the dispatch by load block for the base case, the high gas case and the additional wind case respectively.

15 ___. *EPA Impact Analysis. MISO. October 2011.*

Figure 3



Base Case:
Annual Generation by Resource
Generation (GW)
120
100
80
60
40
20
0
1
1001
2001
3001
4001
5001
6001
7001
8001
Hours →
New Gas CT
New Gas CC
New Wind Firm
Existing Coal with Retrofits
Existing excluding conventional coal
High Gas Case:
Annual Generation by Resource
Generation (GW)
Hours →
New Gas CT
New Gas CC
New Wind Firm
Existing Coal with Retrofits
Existing excluding conventional coal
Additional Wind Case:
Annual Generation by Resource
Generation (GW)
Hours →
New Gas CT
New Gas CC
New Wind Firm
Existing Coal with Retrofits
Existing excluding conventional coal

Figure 4 illustrates the projected annual quantity of energy from each major source under each case in 2020.

Figure 4

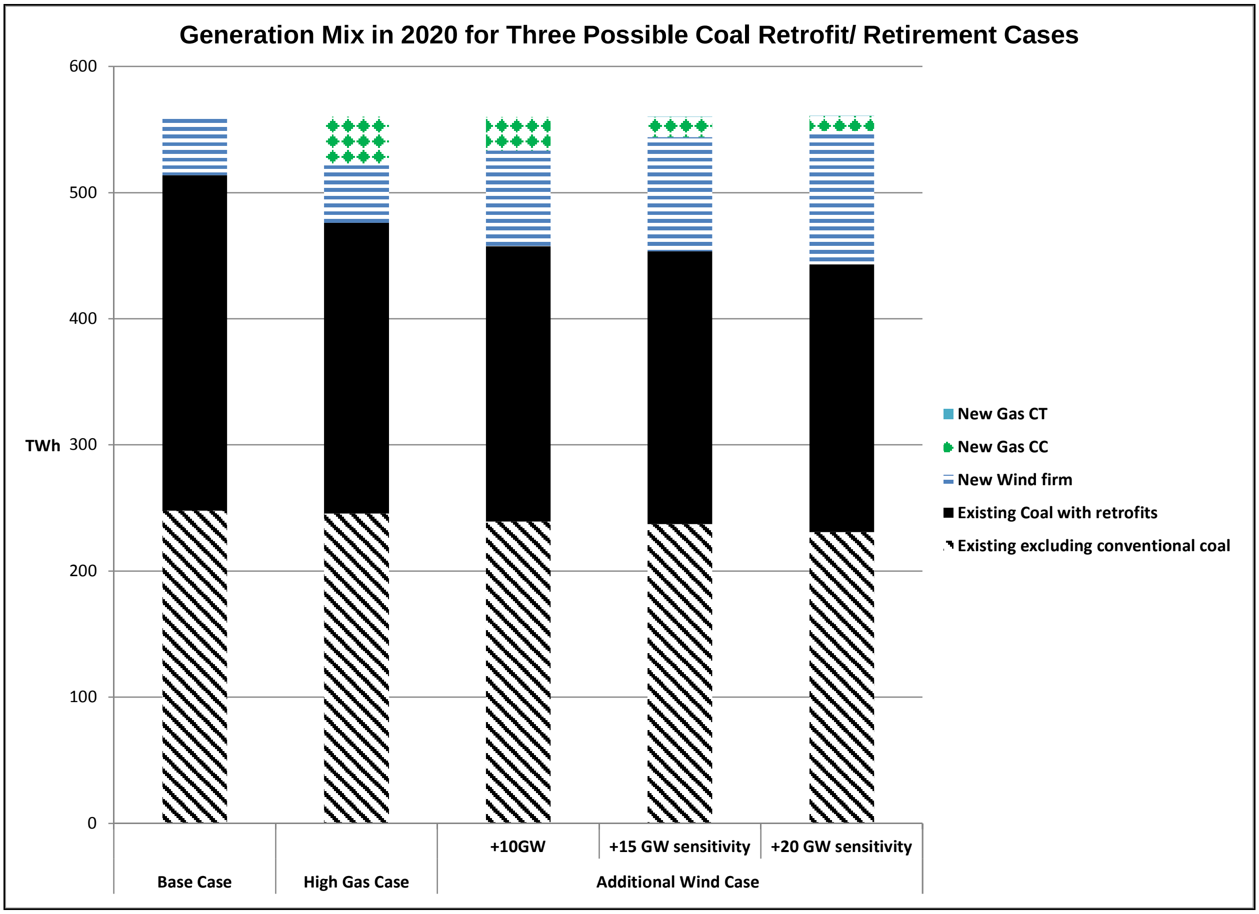
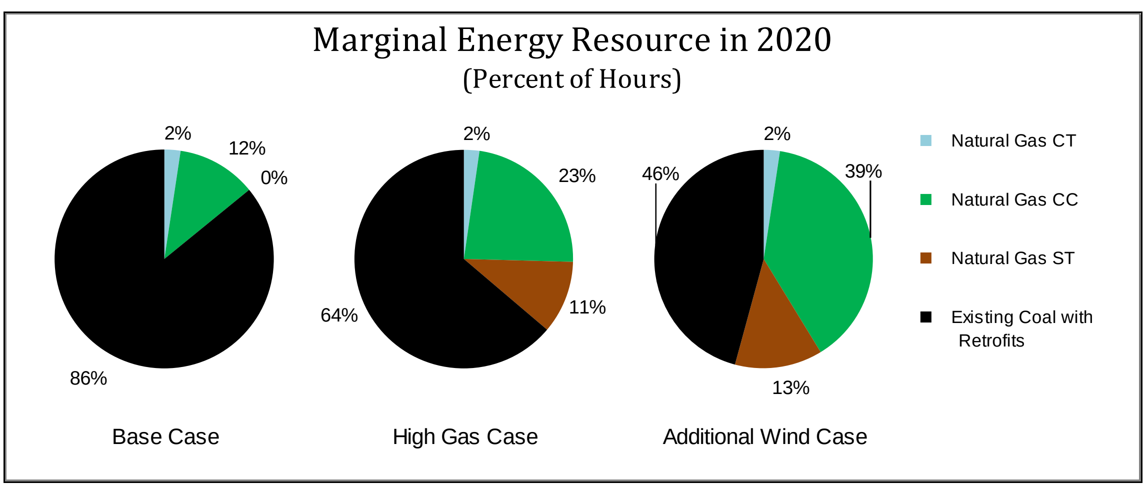


Figure 5 identifies the distribution of marginal resources under each case.

Figure 5



Our analyses indicate that the high gas case and the additional wind case each have a somewhat lower total annual cost of electric energy plus incremental revenue requirements than the base case. Table 2 summarizes those electricity market cost impacts.

The high gas case has a slightly higher (0.2%) annual average wholesale electric energy price than the base case. However its total annual cost of electric energy plus incremental revenue requirements is 2.4% lower. This lower total amount is due to our projection of somewhat lower incremental revenue requirements under the high gas case relative to the base case.

The wind case has a slightly lower (0.6%) annual average wholesale electric energy price than the base case as well as a lower total annual cost of electric energy plus incremental revenue requirements (1.2%). However, the wind case has a higher total annual cost of electric energy plus incremental revenue requirements than the high gas case. This higher total amount is due to our projection of somewhat higher incremental revenue requirements under the wind case relative to the high gas case.

The two wind sensitivity cases each have progressively lower annual average wholesale electric energy prices than the base case and lower total annual costs of electric energy plus incremental revenue requirements. However, the two wind sensitivity cases indicate that as more wind capacity is added beyond 25.4 GW the savings relative to the base case begin to decline. The increasing incremental revenue requirements associated with these capacity additions offsets their reductions in annual average wholesale electric energy prices.

Table 2. Impact on wholesale electric market in 2020 ($2010)

Parameter	Base Case	High Gas Case	Additional Wind Case (+10 GW)	Additional Wind Case sensitivity (+15 GW)	Additional Wind Case sensitivity (+20 GW)
Average annual wholesale energy price ($/MWh)	$47.02	$47.10	$46.75	$46.66	$46.30
Change vs. base case ($/MWh)		$0.08	($0.27)	($0.36)	($0.72)
Change vs. base case (%)		0.2%	-0.6%	-0.8%	-1.5%
Change vs. high gas case (%)			-0.7%	-0.9%	-1.7%
Wholesale electric energy cost ($ million)	$26,331	$26,388	$26,187	$26,131	$25,970
Revenue requirement in 2020 associated with incremental capital costs ($ million)	$4,687	$3,885	$4,454	$4,738	$5,031
Total amount ($ million)	$31,018	$30,273	$30,641	$30,869	$31,001
Change vs. base case		-2.4%	-1.2%	-0.5%	-0.1%
Change vs. high gas case			+1.2%	+2.0%	+2.4%

6. Potential impacts on wholesale natural gas market in 2020

The major potential impacts of the retirement of coal units in MISO on the region's wholesale natural gas market will depend on the extent to which the region turns to generation from gas-fired units as a replacement for coal units that retire. Our report assesses the implications of additional gas-fired generation on average annual wholesale natural gas prices in the MISO region in 2020 and on gas transmission infrastructure in the region. The assessment addresses two main questions:

- How will additional gas consumption for power generation affect wholesale natural gas prices in the MISO region?
- Will limitations of the existing gas delivery system constrain use of gas for electric generation within the MISO region?

A. Estimates of additional gas consumption for power generation

The first step in our assessment of the impacts of the retirement of coal units in MISO on the region's wholesale natural gas market was to estimate the potential change in annual gas use for electric generation, as well as the change in the approximate location of that gas use, relative to current gas use for electric generation in MISO.

Our analysis estimates that gas use for electric generation in MISO was approximately 275 Bcf, or 0.75 Bcf per day in 2010. This estimate reflects the fact that many of the gas-fired plants in the MISO market are peaking units, and existing CC units tended to operate at relatively low capacity factors during this time period.

Our projection of generation in 2020 using the production costing model provided estimates of the annual quantity of gas use for electric generation under each case. The projections are as follows:

- **Base case:** Total gas use for electric generation in this case is projected to be 1.08 Bcf per day, which is approximately 0.3 Bcf per day higher than in 2010. The gas consumption in 2020 is higher in the West region of MISO and lower in Michigan and Indiana.[16] This change in the location of gas consumption reflects changes in the operation of existing combined-cycle generating plants in those areas, i.e., increases in annual capacity factors.
- **High gas case:** Total gas use for electric generation in this case is projected to be 1.7 Bcf per day, approximately 1 Bcf per day higher than in 2010 and a 60 percent increase over the base case. Much of the increase in gas consumption relative to the base case occurs in Indiana and Michigan.

[16] The regions used in the study are not identified using state borders, but are instead aggregations of control areas/ planning areas. The West region of MISO consists of IA, MN, MT, ND, SD as well as portions of WI and IL.

- **Additional wind case:** Total gas use for electric generation in this case, and the two sensitivities, is greater than in 2010 and the base case, but less than the high gas case. This reflects the reduced reliance on new gas-fired CC units for capacity and generation.

B. How will additional gas consumption for power generation affect wholesale natural gas prices in the MISO region?

Wholesale natural gas prices in the MISO region consist of two main components: a production price and a location differential or "basis". Our report uses the Henry Hub price as a measure of natural gas production prices at the national level and the difference between the Henry Hub price and the regional market price as the basis. The Henry Hub price is, by far, the larger of these two components. For example, the Chicago city-gate price is a representative wholesale gas price in MISO. In 2011 the average Chicago city-gate price was $4.11 per MMBtu, while the average Henry Hub price was $3.99 per MMBtu, indicating a Chicago region basis of $0.12 per MMBtu (i.e., $4.11 - $3.99).

Henry Hub Price

Our report uses the AEO 2012 Reference Case forecast as the source of the Henry Hub price in 2020. That AEO 2012 forecast projects a 30 percent increase in gas use for electricity generation from 2010 to 2020 for a region approximating MISO.[17] In order for additional gas consumption for power generation to have an impact on Henry Hub prices in 2020, that consumption would need to be incremental to the 30 percent increase in MISO region gas use for electric generation that we assume the EIA has already factored into its AEO 2012 Reference Case price forecast.

Our study calculates the consumption of gas for each case that is incremental to the AEO 2012 Reference case by subtracting 0.977 bcf/day, which is 130 percent of the estimated 2010 gas use for electric generation in MISO, from our projection for each case. The resulting estimates of the incremental gas use for electric generation under each of our cases relative to the AEO 2012 Reference Case are presented in Table 3.

Table 3. Gas for Electric Generation in MISO (Bcfd)

	Base Case	High Gas Case	Additional Wind Case (+10 GW)	Additional Wind Case sensitivity (+15 GW)	Additional Wind Case sensitivity (+20 GW)
Annual Gas Use for Electric Generation (Bcfd)	1.076	1.721	1.411	1.189	1.012
Increment to AEO 2012 Reference Case forecast for 2020 of 0.977 (Bcfd)	0.099	0.744	0.434	0.212	0.035

The incremental gas use for electricity generation in all cases except the high gas case is closer to the growth in demand that is already included in the AEO 2012 Reference Case, so there is less reason to expect those increments would cause an increase in Henry Hub prices. In contrast, the

[17] West North Central plus East North Central census regions.

incremental annual gas use for electricity generation under the high gas case is approximately 0.75 Bcf per day. Based on the results of recent gas supply price elasticity projections prepared by Navigant and EIA, incremental gas production required to supply incremental consumption of that magnitude could cause a short-term increase in the Henry Hub price in the order of 2 to 4 percent.[18] (As mentioned earlier, it is important to note that forecasting Henry Hub prices has proven to be very difficult over the years, and there are a wide range of forecasts of Henry Hub prices and gas production.)

MISO Region Price Basis

The regional gas price basis is affected by the availability and cost of pipeline transportation into, and within, the region. Our analysis of pipeline transportation capacity into, and within, the MISO region indicates that pipeline capacity into the region will likely be adequate to supply gas for additional gas-fired generation. However, the adequacy of pipeline capacity within the region to deliver to new gas-fired units will depend largely on where new gas-fired units in the high gas case are located relative to existing pipelines within MISO. Thus, while we do not expect incremental gas use in the high gas case to increase the basis for the MISO region as a whole, it may have an upward impact on the basis in local markets within the MISO region where specific gas transmission capacity is more constrained.

C. Will limitations of the existing gas delivery system constrain use of gas for electric generation?

The addition of new gas-fired units has the potential to affect the natural gas delivery grid at two major levels: capacity into the region and capacity within the region. Additional mainline transmission capacity may be needed to bring more gas into the MISO region to supply the increase in natural gas use for power generation. Pipelines and gas distribution companies within the region may need to invest in upgrades, or major new laterals, in order to transport gas to new gas-fired units depending on where those new units are located.

Our analysis indicates that pipeline capacity into the MISO region will likely be adequate to supply gas for additional gas-fired generation.

- First, there is currently surplus annual pipeline capacity into the MISO region that could be used to support additional gas-fired generating capacity. The EIA estimates that the total current capacity of natural gas pipelines entering the MISO region is approximately 25 Bcf per day. Total natural gas use within the MISO region and deliveries from the MISO region was approximately 15.4 Bcf/day in 2010. The difference between the total pipeline capacity entering the MISO region and the average daily flows into the region reflects capacity that is used during the peak winter season to deliver gas into the Upper Midwest from production-area natural gas storage facilities. However, that difference also reflects some quantity of surplus annual pipeline capacity that could be used to support additional gas-fired generating capacity. A recent study sponsored by MISO indicates that while available capacity varies considerably across the pipeline systems supplying the MISO

[18] Navigant Consulting, “North America Gas System Model to 2040”, September 2011, and EIA, “Effect of Increased Natural Gas Exports on Domestic Energy Markets”, January 2012.

region, there is existing capacity available to provide incremental transportation services to power generators.[19]

- Second, it is reasonable to expect further additions to the pipeline capacity into the MISO region. Over the past ten years, pipeline capacity into the region has expanded approximately 17 percent as a result of large producer-driven projects that transport gas through the Upper Midwest to markets in Eastern Canada and the Northeast U.S. It is reasonable to expect continued growth in unconventional natural gas production will lead to shifts in natural gas flow patterns. For example, production from the Marcellus and Utica shales in Pennsylvania and Ohio may allow existing west-to-east pipeline capacity currently used to deliver gas to the Northeast region to be used to supply markets in the Midwest, while further increases in gas production in the Rockies area is expected to result in supplier-driven pipeline projects.

Pipeline capacity within MISO may, or may not, be adequate to supply new gas-fired units. The adequacy of that capacity will depend largely on where new gas-fired units in the high gas case are located relative to existing pipelines within MISO. The natural gas pipelines that operate in the MISO region include major long-haul pipelines that transport gas from outside the region to major market “hubs,” such as Chicago and Detroit; pipelines that transport gas into the MISO region, but also supply downstream markets (e.g., Great Lakes Gas Transmission, Texas Eastern, and Rockies Express); and regional pipelines that transport gas from market hubs to local markets (e.g., Guardian Pipeline). Some pipelines, such as Northern Natural Gas, which supplies much of the Minnesota and Iowa markets, combine a long-haul mainline system with a network of smaller diameter delivery lines within the region. The extent to which the capacity of regional pipelines will need to expand to supply new electric generating capacity will depend on location. Generally speaking, the opportunities to tap directly into major long-haul pipelines with available delivery capacity are likely to be greater in Illinois and Indiana, where multiple pipelines cross the area and where the Rockies Express pipeline was recently completed, than in areas such as Minnesota or western Wisconsin.

The addition of new gas-fired units will also require investment in laterals and metering facilities in order to connect to the natural gas transmission grid. These plant-specific facilities are designed to supply the plant’s maximum hourly gas use. Large generating plants typically connect directly to major gas transmission lines through a dedicated lateral pipeline. These interconnection facilities may be constructed and operated by an interstate pipeline company, a local gas distribution company, or the plant operator. The interconnection costs will depend on the size of the generating facility, but are also greatly affected by the plant’s location relative to existing high-pressure pipelines. For example, interconnection costs for the new large gas-fired generating plants that have been built in Ontario within the last five years to support the province’s coal replacement policy have ranged from $4.6 million for a plant located beside a major pipeline in a rural area, to $42.5 million for a plant located near downtown Toronto. The total cost of gas interconnection facilities for the 4,430 MW of gas-fired generation that has been built in Ontario since 2008 is about $150 million. The high gas case requires 5,000 MW of additional combined-cycle generating capacity. Based on the Ontario experience, the gas interconnection costs for

[19] “Gas and Electric Infrastructure Interdependency Analysis,” February 22, 2012.

5,000 MW of new gas-fired capacity would be approximately $175 million. Interconnection costs of that magnitude would represent approximately 3 percent of total gas-related incremental capital costs in the High Gas case, and less than 0.2 percent of total incremental capital costs for that case.

7. Conclusion

Existing coal-fired generating units located in the region covered by MISO, like existing coal units throughout the United States, face the need to comply with a number of tighter and new federal emission standards expected to take effect between 2015 and 2020. It is generally expected that plant operators will elect to retire a limited number of older, smaller units rather than to invest in the new emission controls required to comply with these emission standards. However, there is considerable uncertainty regarding the number and capacity of larger units that will be retired, what new resources will replace that retiring capacity, and what the potential implications are for the region's electricity and natural gas markets.

Our key conclusions regarding the potential implications for the region's electricity market are as follows:

- With a PRM of 19 percent, 15.4 GW to 25.4 GW of wind capacity could be added in MISO in 2020, and credited with firm capacity, without the support of new natural gas or other generation capacity. We assume there would be no material incremental transmission costs, relative to current MISO transmission investment plans, required to support those quantities of incremental wind capacity.
- The high gas case and the additional wind case both have a somewhat lower total annual cost of electric energy plus incremental revenue requirements than the base case.
- The wind case has a higher total annual cost of electric energy plus incremental revenue requirements than the high gas case.
- The two wind sensitivity cases indicate that as more wind capacity is added beyond 25.4 GW, the savings relative to the base case begin to decline.

Our key conclusions regarding the potential implications for the region's natural gas market and infrastructure are as follows:

- Additional gas consumption for generation under the high gas case has the potential to increase wholesale natural gas prices in the MISO region. Based on studies by EIA and Navigant the that incremental use could cause a short term increase in the Henry Hub price of 2 to 4 percent. However, forecasting Henry Hub prices has proven to be very difficult over the years and there are a wide range of forecasts of Henry Hub prices and gas production.
- We do not expect incremental gas use in the high gas case to increase the basis for the MISO region as a whole, but it may cause increases in the basis at specific locations within the MISO region where gas transmission capacity is more constrained.
- Pipeline transportation capacity into the MISO region will likely be adequate to supply gas for additional gas-fired generation. However, the adequacy of pipeline capacity within the

region to deliver to new gas-fired units will depend largely on where new gas-fired units are located relative to existing pipelines within MISO.

- Gas interconnection costs for new gas-fired generating plants will depend on the size of the plant and its location relative to existing gas transmission lines. If new gas-fired capacity is built at sites that already have access to natural gas, these costs should be less.

Appendix A. Assumptions

This appendix summarizes our general analytical approach and key input assumptions. The study was prepared for the MISO region in 2020. This region encompasses all, or portions of, eleven states (Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Montana, North Dakota, South Dakota, Wisconsin) and the Canadian province of Manitoba. All monetary values are expressed in constant 2010 year dollars, unless noted otherwise.

A. Federal emission standards and compliance measures

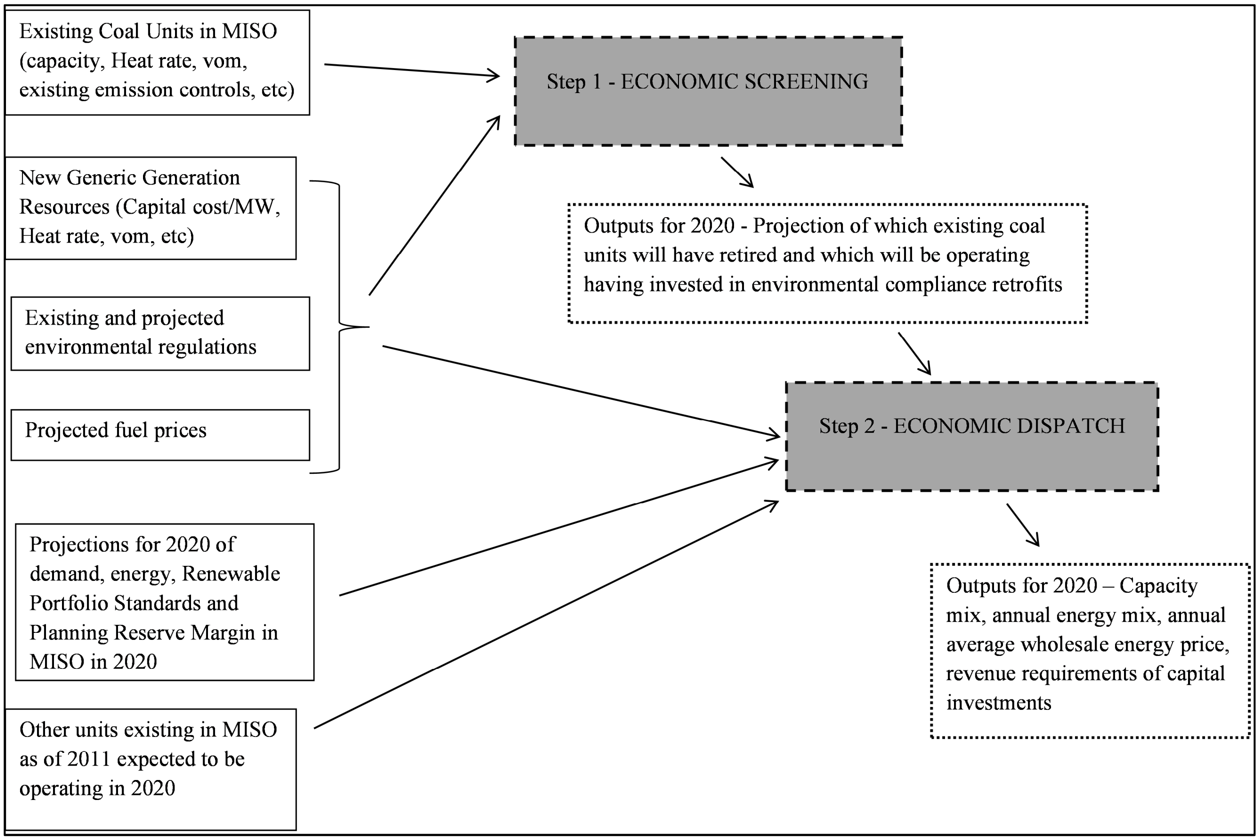
This report assumes that fossil fuel units operating in 2020 will have to comply with six federal emission standards: the Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standards (MATS, Coal Combustion Residuals (CCR), Clean Water Act § 316(b)[1], Waste Water Rule, and Carbon Dioxide Emissions. Those rules are summarized in Table A-1.

Our analyses assumed that the CSAPR and MATS standards would be in effect in 2015. However, the effective date of CSAPR is now unknown. On August 21, 2012 the United States Court of Appeals for the District of Columbia issued a decision vacating CSAPR. Depending on the outcome of the anticipated appeals of that decision the same rule, or a replacement rule requiring the same reductions, may go into effect sometime between 2016 and 2019. We believe our projections for 2020 are still relevant since many utilities that had decided to invest in retrofits have already begun to make those capital expenditures and because units that were planning on retiring will likely continue to operate until the MATS deadline.

B. General Analytical Approach

The general analytical approach consisted of two major steps, economic screening of existing coal units and economic dispatch in 2020. We used the results of the economic dispatch to estimate the average annual wholesale marginal energy cost ($/MWh) in 2020 and the quantities of natural gas used for electric generation in the MISO region. The two steps are illustrated in Figure 1 and summarized below.

[1] Also referred to as Cooling Water Intake Standard (CWIS).



Economic Screening

The economic screening estimated the long-term going-forward economics of each existing non-cogenerating coal-fired generating unit potentially available to serve MISO load.

Page 1 of Table A-2 summarizes the findings from our review of existing capacity located in MISO in 2011. Our analysis identified 241 existing conventional coal units located in MISO, representing 59.7 GW of existing capacity, which would have to comply with the tighter and new emission standards. Our review identified an additional 70 GW of other capacity existing as of 2011 that would not incur material capital costs in order to comply with the new and tighter standards. The source of this list of generating units is Ventyx EPM Simulation Ready Data. It reflects our review of public announcements of coal unit retirements as of June 1, 2012. Our input data for each of these existing generating units consists of heat rates, outage rates, fuel types, online year, variable O&M, and fixed O&M drawn from EIA Form 860 2010 dataset, EIA Form 923 2010 dataset, EPA Air Markets Program Data 2011 dataset, 2010 NERC Special Reliability Scenario Assessment, and Ventyx EPM Simulation Ready Data, NERC Database, Release 9.1.0, February 2011.

Page 2 of Table A-2 summarizes the findings from our review of existing gas-fired capacity located in MISO in 2011.

The long-term going-forward economics were evaluated relative to the costs of building a similarly sized new natural gas-fired combined cycle unit (NGCC) and operating that generic CC at a capacity factor similar to the specific existing coal unit being evaluated. The model uses the going forward costs of a new NGCC as the reference point because a new NGCC is generally assumed to be the lowest cost new source of base load capacity and energy. The model calculates the going-forward economics of continuing to operate each existing unit in compliance with all environmental regulations under a retrofit option and a gas conversion option. The retrofit option estimates the total incremental costs, i.e., all projected capital costs and annual variable costs, if any, the unit would require for environmental control technologies to comply with all emission regulations expected to be in effect from 2015 onward. The gas conversion option estimates the total incremental costs that would be required to convert, and operate, that existing unit as a gas-fired unit.

The going forward costs are expressed as a levelized total cost of energy ($/MWh) over the respective projected life of the unit. The projection of the most likely case for each existing unit is made by comparing the levelized cost of energy from each unit under each option to the levelized cost of energy from a new gas CC. The decision rule is as follows:

- If the total forward cost of the retrofit option is less than the total forward cost of the conversion option and less than the total forward cost of a new gas CC, the economic decision is to retrofit;
- If the total forward cost of the retrofit option is greater than the total forward cost of the conversion option, but the total forward cost of the conversion option is less than the total forward cost of a new gas CC, the economic decision is to convert; and
- If the total forward cost of the conversion option is greater than the total forward cost of a new gas CC, the economic decision is to retire.

In other words the economic screening model determines whether a given unit will be retrofitted, converted to natural gas, or retired based upon its levelized going-forward costs, in $/MWh, relative to those of a new NGCC.

Input assumptions

The model calculates the total forward or incremental cost of retrofitting each existing unit with the specific environmental controls it would require to comply with the environmental regulations over its expected life. The projections are based upon the following financial assumptions:

- Inflation Rate of 2.00%.
- Nominal Discount Rate of 6.8%. This rate represents the value for an independent power producer with a mix of equity and bond financing. Based on a 50/50 equity/debt mix with 10% for

equity and 6% for debt. This rate is used for levelization of capital expenditures. Actual rates for specific projects will vary depending on the nature of the project and the implementing entity.

- Combined Income Tax Rate of 40%, i.e. federal plus state. The rate for property tax rate is the nominal level of 0.5% per annum of the initial plant cost (local rates vary considerably).
- Capital recovery factors of 12.7% (over 15 years for environmental retrofits) and 8.5% (over 30 years for new natural gas combined cycle units and repowering of coal units to natural gas).

Table A-3 provides the performance and cost assumptions for each type of generic generating unit. These consist primarily of capital cost, heat rates, variable operation and maintenance and outage rates. They do not assume any Production Tax Credits, or other tax credits, for wind. All assumptions except for outage rates are drawn from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2011 and the National Renewable Energy Laboratory (NREL) February 2012 paper "Recent developments in the Levelized Cost of Energy from U.S. Wind Power Projects".

Our assumptions regarding new generation resource performance and costs reflect our review of the following reports:

- EIA 2010, *Updated Capital Cost Estimates for Electricity Generation Plants*, US EIA, November 2010, http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf
- Black & Veatch, 2011. Ryan Pletka, *Black & Veatch's (RETI's) Cost of Generation Calculator*, Presentation to the California Energy Commission Cost of Generation Workshop. May 16, 2011.
- E3 Analytics 2010, Energy and Environmental Economics. *Capital Cost Recommendations for 2009 TEPPC Study*, (Available at: http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/Forms/AllItems.aspx)
- EPRI 2011, *Program on Technology Innovation: Integrated Generation Technology Options*, Electric Power Research Institute, publication 1022782, Technical Update June 2011, www.epri.com
- Lazard 2010. Lazard, Ltd. *Levelized Cost of Energy Analysis – Version 4.0*. May, 2010. (Not really public although widely distributed.)
- NREL 2010, *Cost and Performance Assumptions for Modeling Electricity Generation Technologies*, ICF International, NREL/SR-6A20-48595, www.nrel.gov

Table A-4 provides our assumptions regarding prices of coal and of natural gas delivered to power plants in MISO. These consist of the production costs of those fuels plus the additional cost of delivering those fuels from their source of production to the power plants. We developed the production cost component of those delivered prices using projections of coal mine mouth prices (Powder River Basin, Illinois Basin, and Appalachian) and Henry Hub natural gas prices from the EIA AEO 2012 Reference Case. We developed the delivery cost, or basis differential, component of those delivered prices using forecast adders for each MISO state derived from Ventyx EPM Simulation Ready Data, NERC Database, Release 9.1.0, February 2011. The adders for coal reflect Ventyx Advisors' market-based forecasts of the demand for coal at individual power plants, the supply of coal from existing mines, and the available modes of transportation. The adders for natural gas are based on forecasts prepared by the Ventyx Advisors' Fuels team using a general equilibrium model of gas supply and demand. Those adders are proprietary to Ventyx and covered by copyright. As a high-level check for reasonableness Synapse has compared the adders from Ventyx to the adders reflected in AEO 2012.

Economic Dispatch model

The economic dispatch model determines the current most likely mix of energy, and associated energy costs, to meet MISO region annual load in in 2020. Synapse developed and applied this model to prepare its May 2011 report, *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region.* The economic dispatch mode provides a simplified representation of the MISO wholesale energy market using Excel.

The model's core characteristics are as follows:

- **Capacity mix**. The mix of capacity available to be dispatched will consist of the existing coal units projected to continue operation from step one, plus the non-coal existing capacity expected to be operating in 2020, plus new renewable capacity added to meet RPS requirements in 2020 plus new natural gas generating units expected to be built and/or needed to meet the 2020 reserve margin.
- **Single energy zone.** For the purposes of this modeling exercise, we will assume a single energy zone, encompassing the entire MISO region.
- **Supply curve**. The supply curve will be based upon the variable cost of production of each of the units in the capacity mix. That variable cost of production of each unit in the capacity fleet will be a function of our assumptions regarding heat rates, fuel prices, VOM and environmental regulations described earlier.
- **Outages.** We will use a planned outage assumption of 8% for all non-wind resources, and we will spread these outages out across "shoulder season" (i.e., spring and fall) load blocks. We will use forced outage data from our Ventyx data set to define "derated" net capacity values for all non-wind supply resources. Wind resource output values will use aggregate average capacity values by load block and by MISO sub-region.
- **MISO region peak load projection**. We will use the MISO region peak load projection, as reported in MTEP 2011 and in the NERC 2011 LTRA.

- **20 load blocks per year.** Load patterns vary daily and seasonally, but with a large degree of predictability, within certain error bounds. Conventional supply resources can be economically dispatched to meet these patterns. We will define twenty load blocks per year, across each of summer, winter, and shoulder seasons. These blocks will capture the broad patterns of supply and demand. Each block will be modeled as a fraction of the highest peak demand projected for the MISO region. The load block definition will allow us to capture the price effects during "peaky" periods, and to discern wind output differences that exist between day and night, and between winter, summer, and spring and fall. The block representation will allow us to assign planned outage periods to shoulder seasons.
- **Uniform energy market clearing price.** For each block, we will "clear the market" by using the applicable system supply curve—which incorporates average wind output that respects the seasonal and diurnal variability.

Table A-5 presents the projected peak load (MW) and annual energy (GWh) for MISO in 2020. This data is obtained from MISO's 2011 MTEP (MISO Transmission Expansion Plan) document, and associated appendices (Peak); and from their tariff filing for projected annual energy. Our report uses a conservative minimum planning reserve margin for 2020 of 19%. MISO's 2011 minimum planning reserve margin is 17.4%, and their projected 2020 minimum planning reserve margin is 18.4%. It is obtained from the Planning Year 2011 LOLE Study Report", available at https://www.midwestiso.org/Library/Repository/Study/LOLE/2011%20LOLE%20Study%20Report.pdf,

Table A-6 presents our estimate of the additional wind capacity that will have to be added by 2020 to meet the estimated Renewable Portfolio Standards (RPS) of states in MISO with an RPS. The projected percentage RPS requirements in 2020 are drawn from the Database of State Incentives for renewables and efficiency (www.DSIREusa.org). Those percentages are multiplied by 2010 sales in those states, from EIA Form 861-File2, to estimate the MWh that we assume would be me from wind. We estimated the GW of wind which would have to be added to produce that MWh using the EIPC assumption that wind units would have an average capacity factor of 35 percent .

Table A- 1. Environmental Regulation assumptions

The Environmental Protection Agency (EPA) has recently proposed a number of regulations, in various stages of promulgation, which may have a significant impact on coal-fired generation in the MISO region. Utilities are currently in the process of determining whether to retrofit existing coal units with necessary pollution control technologies, or to retire uneconomic coal units. The sections below describe the relevant EPA regulations.

Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule (CSAPR) was finalized by EPA on July 6, 2011. The Rule is designed to reduce emissions of SO_2 and NO_x from power plants that cross state lines and contribute to ground-level ozone and fine particle pollution in those neighboring states. Emissions reductions under CSAPR will occur in two phases. Phase 1 begins on January 1, 2012 for SO_2 and annual NO_x, and on May 1, 2012 for ozone season NO_x. Phase 2 will reduce emissions of SO_2 at a greater rate and will begin on January 1, 2014. EPA estimates that CSAPR and other federal rules will result in power plant emissions reductions of 73% of SO_2 and 54% of NO_x from 2005 levels by 2014.

Of the MISO states, Nebraska, Kansas and Minnesota must control for annual SO_2 and NO_x only. Missouri, Iowa, Wisconsin, Illinois, Indiana, Ohio and Michigan must control for ozone season NO_x in addition to annual NO_x and SO2. Some emissions allowance trading is permitted under CSAPR among covered sources within the same program (e.g. annual SO_2) in the same or different states, however, an emission ceiling is established for each state, and emissions shifting that occurs as a result of allowance trading shall not exceed that ceiling.

On August 21, 2012 the United States Court of Appeals for the District of Columbia issued a decision vacating CSAPR. Depending on the outcome of the anticipated appeals of that decision the same rule, or a replacement rule requiring the same reductions, may go into effect sometime between 2016 and 2019.

Mercury and Air Toxics Standards

The final Mercury and Air Toxics Standards (MATS) Rule was announced by EPA on December 21, 2011, and limits the emissions of mercury, total metals, particulate matter, hydrogen chloride, and sulfur dioxide from new and existing power plants. When examining the impacts of these standards, EPA suggested that many power plants would need to install widely available pollution control technologies in order to reduce emissions. These control technologies include the following: wet scrubbers (flue gas desulfurization systems), selective catalytic reduction systems, activated carbon injection systems, and baghouses. Standards include: 1.2 pounds per trillion Btu (lb/TBtu) for mercury, 0.0020 pounds per million Btu (lb/MMBtu) for acid gases or a surrogate 0.20 lb/MMBtu SO_2 limit, and individually prescribed limits for non-mercury metals or a surrogate 0.030 lb/MMBtu filterable particulate matter limit. Existing generators would have three years after the standards become effective to comply with the MATS rule, and may ask for a one-year extension to install controls. Coal units are expected to meet compliance standards in 2015.

Coal Combustion Residuals

Following the accidental release of fly ash, bottom ash, and coal combustion byproducts from the ash pond at the Tennessee Valley Authority's Kingston power plant, federal and state officials began to call for greater regulation of these coal combustion residuals (CCRs). On May 4, 2010, EPA released a proposal that offered two approaches for the disposal and management of CCRs under the Resource Conservation and Recovery Act (RCRA), the first approach under Subtitle C of the Act and the second approach under Subtitle D.

Under the Subtitle C approach, CCRs would be a special waste from its generation to its disposition. Regulations establish location restrictions, standards for ash pond liners, leachate collection and removal systems, groundwater monitoring for landfill disposal units, fugitive dust control, closure and post-closure care requirements, storage requirements, collective action, financial assurance, waste characterization, and permitting requirements.

Under the Subtitle D approach, EPA would establish minimum nationwide standards for the disposal of CCRs, akin to the standards for municipal solid waste (non-hazardous waste). These standards would restrict placement of CCR landfills and surface impoundments in certain areas, and new landfills and surface impoundments would be required to install a composite liner and leachate collection and removal system. Existing landfills and surface impoundments in certain areas would have to be closed until they could meet more stringent safety requirements.

Requirements of each proposal would take effect at different times. For Subtitle C, the CCR requirements would go into effect when individual states adopt the rule; timing would therefore vary from state to state. For Subtitle D, the rule would become effective six months after promulgation.

Clean Water Act § 316(b)

Section 316(b) of the Clean Water Act requires that new power plants use the best available cooling water intake technologies for minimizing adverse environmental impacts.[1] Adverse environmental impacts include the intake of aquatic organisms with cooling water when using once-through systems.

The EPA promulgated a 316(b) rule in 2004 that covered large existing power plants with water intake in excess of 50 million gallons per day. In 2007, the Second Circuit Court of Appeals remanded this rule to the EPA. Absent federal regulations, states have begun to consider and adopt rules governing the retrofit of existing power plants with closed-loop cooling systems. EPA is developing revised national regulatory standards implementing Section 316(b) for existing power plants and manufacturing facilities, and published the draft rule in April 2011.

The proposed 316(b) rule has three components: 1) existing facilities that withdraw more than 2 million gallons of water per day, and withdraw 25% of water from an adjacent water body for cooling purposes, would be subject to an impingement limit, which restricts the number of fish that can be killed by being pinned against intake screens. The facility could also reduce water intake velocity to 0.5 feet per second or less; 2) Existing facilities withdrawing 125 million gallons of water per day or more would be required to conduct studies to determine if controls would be required to reduce entrainment of aquatic organisms in cooling water systems; and 3) New units would be required to add technology that is equivalent to recirculating cooling technology.

EPA estimates that this rule covers approximately 1,260 existing facilities, of which 670 are power plants. Compliance dates will not be relevant until EPA has issued the final rule, but power plants are expected to have to comply by no later than 2020.

Waste Water Rule

Following a multi-year study of steam generating units across the country, EPA found that coal-fired power plants are currently discharging a higher-than-expected level of toxic-weighted pollutants. Current effluent regulations were last updated in 1982 and do not reflect the changes that have occurred in the electric power industry over the last thirty years, and do not adequately manage the pollutants being discharged from coal-fired generating units. Coal ash ponds and flue gas desulfurization (FGD) systems used by such power plants are the source of a large portion of these pollutants, which are likely to increase in the future environmental regulations are promulgated and as pollution controls are installed. No new rule has yet been proposed, but EPA intends to issue the proposed regulation in mid-2012 and a final rule in late 2013.

Carbon Dioxide Emissions Compliance

There is considerable uncertainty regarding the timing and design of future federal regulation of carbon emissions. However, Synapse considers it reasonable to assume that some form of federal regulation of carbon emission regulation will be in effect by 2020. A number of electric utilities located in MISO

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[1] Thermal power plants using water for cooling purposes use one of three types of cooling systems: once-through, recirculating, and dry cooling. Once-through systems withdraw water in large volumes and then discharge it back into the same water body at elevated temperatures. Recirculating systems withdraw water in smaller volumes, and continuously circulate the cooling water through a plant's heat exchangers with the aid of cooling towers. Dry cooling systems are closed-loop systems that do not rely on cooling water, but instead on forced draft air flow.

apparently share that expectation, as they have assumed a cost for complying with carbon emission regulation in the long-term plans they filed in 2010 and 2011.

We are proposing to all generating units in MISO, both existing and new, will be subject to federal regulation of carbon emissions beginning in 2020 at a cost of compliance of $15 per ton of carbon. This price, drawn from the Low Case in the *2011 Carbon Dioxide Price Forecast,*[2] is consistent with long-term plans filed by Duke Energy Ohio, Otter Tail Power, Minnesota Power, Indiana Michigan Power Company, and Indianapolis Power and Light. Figure A-5.1, below, shows the Synapse price forecasts against the range of Reference case carbon dioxide forecasts used by utilities across the country. As seen in the Figure, the Synapse Low Case is well within the range of prices used by utilities in resource planning.

[2] Johnston, L., E. Hausman, B. Biewald, R. Wilson and D. White. *2011Carbon Dioxide Price Forecast.* Amended August 10, 2011. Available at: http://www.synapse-energy.com/Downloads/SynapsePaper.2011-02.0.2011-Carbon-Paper.A0029.pdf

Figure A-5.1. Synapse CO_2 Price Forecasts among Various Utility Forecasts.

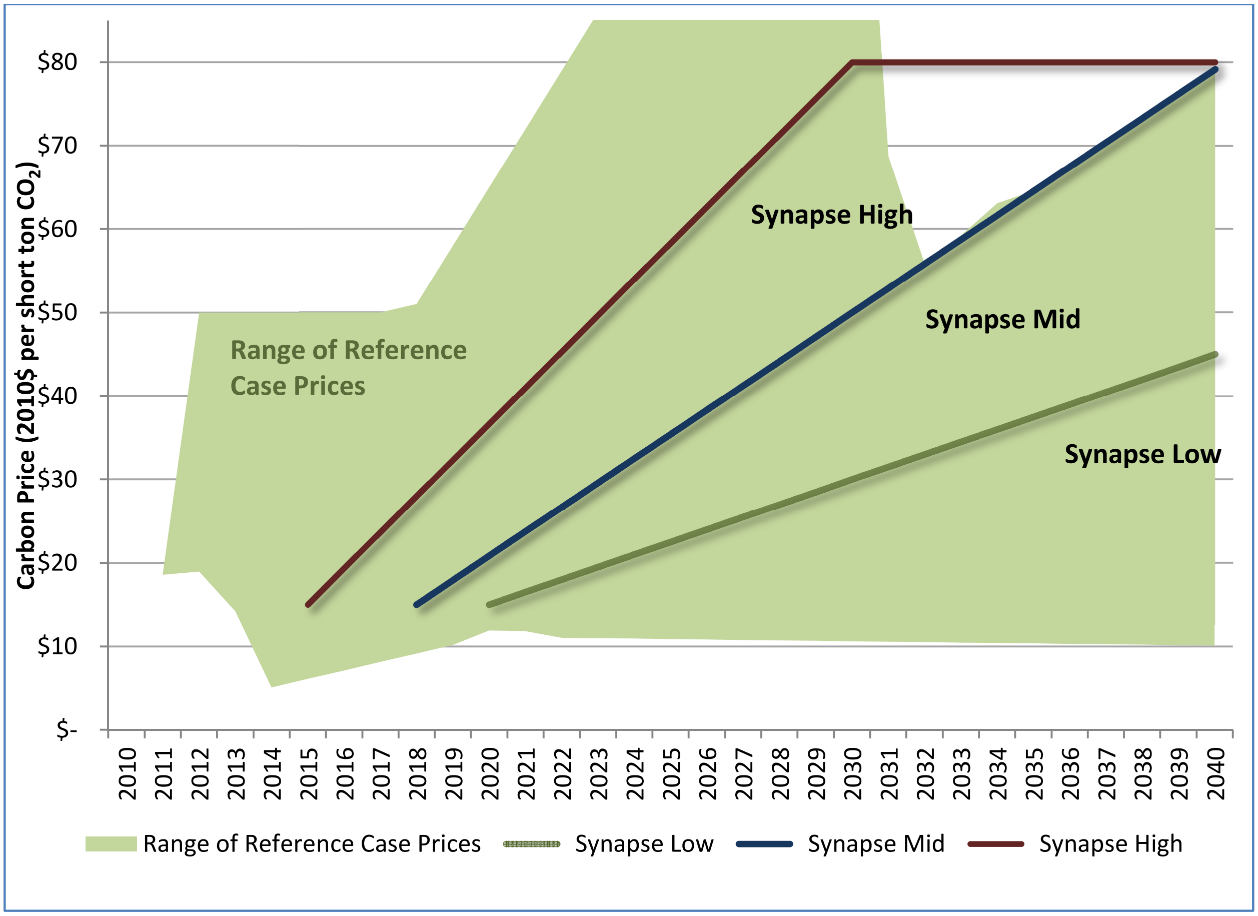

Table A - 2
Capacity (MW) existing in MISO as of 2011

Conventional coal units which would have to comply with new and tighter standards

Tier		Nameplate capacity	
I	Units that would be retrofitted and continue to operate	47,600	80%
II	Units that may or may not be retrofitted	9,200	15%
III	Units most likely to be retired	2,900	5%
	Sub-total	**59,700**	**100%**

Capacity which would not incur material capital costs to comply with new and tighter standards

Fuel	Nameplate capacity	Effective firm capacity
Natural Gas	41,028	41,028
Wind	10,447	1,348
Biomass	351	351
Coal	11,716	11,716
Water	1,431	1,431
Fuel Oil	4,084	4,084
Waste Heat	29	29
Wood	470	470
Uranium	8,531	8,531
Refuse	243	243
Petroleum Coke	127	127
Other	128	128
Pumped	493	493
Kerosene	24	24
Sub-total	**79,102**	**70,002**

Table A-2

Gas Fired Generating Capacity and Gas Use in MISO - 2010

	West	WI	MI	MO-IL	IN	MISO
Gas-Fired Capacity (MW)						
CC	3,583	2,498	2,416	1,349	883	10,729
CT	4,798	3,925	3,868	5,739	3,527	21,857
Other	680	856	5,461	529	917	8,442
Total	9,061	7,279	11,745	7,617	5,327	41,028
Dual-Fuel Capacity (MW)						
CC	1,533	1,316	0	0	0	2,849
CT	3,320	3,452	102	1,445	541	8,860
Other	416	386	2,218	0	0	3,020
Total	5,269	5,154	2,320	1,445	541	14,729
Potential Gas Use (Bcfd)						
Gas-Only Generating Units	0.9	0.5	2.2	1.6	1.2	6.4
Dual Fuel Generating Units	1.3	1.3	0.7	0.4	0.2	3.9
Total	2.2	1.8	2.9	2.1	1.4	10.3
Gas Use for Electric (2010)						
Annual (MMcf)	49,791	42,639	113,245	24,108	44,707	274,490
Avg. Daily (Bcfd)	0.136	0.117	0.310	0.066	0.122	0.752

Gas Fired Generating Capacity and Gas Use in MISO – 2020, High Gas Case

	West	WI	MI	MO-IL	IN	MISO
New Gas Capacity (MW)						
CC	1,000	700	1,000	500	1,800	5,000
CT	0	0	0	0	0	0
Total	1,000	700	1,000	500	1,800	5,000
Potential Gas Use (Bcfd)	2.3	1.9	3.0	2.1	1.7	11.1
Change from Task 3 (Bcfd)	0.2	0.1	0.2	0.1	0.3	0.8
Gas Use for Electricity						
Annual (MMcf)	191,366	128,353	128,912	67,696	111,762	628,089
Avg. Daily (Bcfd)	0.524	0.352	0.353	0.185	0.306	1.721
Change from 2010 (Bcfd)	0.388	0.235	0.043	0.119	0.184	0.969

Note – West MISO encompasses service territories in IA, MN, MT, ND, SD, WI and IL

Table A-3. Performance and Cost Assumptions for New and Existing Generic Resources

Technology	Online Year	Size (MW)	Lead Time (years)	Base Overnight Cost in 2010 (2009 $/kW)	Project Contingency Factor	Total Overnight Cost in 2010 (2009 $/kW)	Variable O&M (2009 $/MWh)	Fixed O&M (2009 $/kW)	Heatrate in 2010 (Btu/kWh)	nth-of-a-kind Heatrate (Btu/kWh)
Conv Gas/Oil Comb Cycle (Existing CC)	2013	540	3	921	1.05	967	3.4	14.22	7050	6800
Adv Gas/Oil Comb Cycle (New CC)	2013	400	3	917	1.08	991	3.1	14.44	6430	6333
Conv Comb Turbine (Existing CT)	2012	85	2	916	1.05	961	8.2	9.75	10745	10450
Adv Comb Turbine (New CT)	2012	210	2	626	1.05	658	6.9	14.52	9750	8550
Wind	2012	1.62				1820	3.4	59.02		

Sources:
CT and CC assumptions: EIA AEO 2011 Assumptions Table 8.2. July 2011.
Wind assumptions: "Recent developments in the Levelized Cost of Energy from U.S. Wind Power Projects". NREL. February 2012.

Table A-4. Fuel Price Projections

Production area	Natural Gas (1) (2010 $/MMBtu)	Coal (2) (2010 $/short ton)			Coal (2010 $/MMBtu)		
	Henry Hub	Appalachia *(North App)*	Interior *(Illinois Basin)*	West (Northern Great Plains) *(PRB)*	Appalachia *(North App)*	Interior *(Illinois Basin)*	West (Northern Great Plains) *(PRB)*
2009	4.00	63.15	35.68	12.63	2.43	1.51	0.72
2010	4.39	69.36	37.74	13.06	2.67	1.60	0.74
2011	3.94	75.54	40.15	13.75	2.91	1.70	0.78
2012	3.58	75.86	40.23	14.09	2.92	1.70	0.80
2013	4.06	77.20	40.78	14.49	2.97	1.73	0.82
2014	4.17	81.02	41.16	15.28	3.12	1.74	0.87
2015	4.29	84.14	41.54	16.20	3.24	1.76	0.92
2016	4.26	83.73	42.24	16.52	3.22	1.79	0.94
2017	4.29	83.04	42.81	16.83	3.19	1.81	0.96
2018	4.34	83.41	43.11	17.19	3.21	1.83	0.98
2019	4.46	84.42	43.15	17.47	3.25	1.83	0.99
2020	4.58	86.47	43.31	17.81	3.33	1.84	1.01
2021	4.82	87.82	43.99	18.18	3.38	1.86	1.03
2022	5.11	89.62	43.92	18.57	3.45	1.86	1.06
2023	5.32	91.96	43.40	19.17	3.54	1.84	1.09
2024	5.46	93.89	43.38	19.73	3.61	1.84	1.12
2025	5.63	96.00	43.51	20.24	3.69	1.84	1.15
2026	5.77	97.26	44.02	20.70	3.74	1.87	1.18
2027	5.94	97.56	43.96	21.12	3.75	1.86	1.20
2028	6.03	99.07	44.63	21.57	3.81	1.89	1.23
2029	6.15	100.00	45.50	22.00	3.85	1.93	1.25
2030	6.29	100.98	46.01	22.46	3.88	1.95	1.28
2031	6.42	103.10	46.63	22.88	3.97	1.98	1.30
2032	6.58	103.37	47.36	23.23	3.98	2.01	1.32
2033	6.71	105.13	47.45	23.50	4.04	2.01	1.34
2034	7.06	106.04	48.04	23.91	4.08	2.04	1.36
2035	7.37	107.36	48.87	24.44	4.13	2.07	1.39

Heat Content (Btu/lb)		13,000	11,800	8,800

Sources:
(1) EIA AEO 2012 ref2012.d020112c, Table 133
(2) EIA AEO 2012 ref2012.d020112c, Table 139
(2) EIA Coal News and Markets. June 2012.

Table A-5. MISO Capacity and Energy Forecasts for 2020

MISO Capacity Forecast

Region	West	East	Central	2011 Forecast
2020	42,770	25,629	36,076	104,475

Source:
2011 MTEP (MISO Transmission Expansion Plan) Resource Assessment, Appendix E6

MISO Energy Forecast

Local Balancing Authority	2010 Withdrawals (MWh)	2020 Withdrawals (MWh)
ALTE	12,186,226	14,031,538
ALTW	19,763,102	22,755,752
AMIL	45,963,542	52,923,621
AMMO	42,844,500	49,332,275
BREC	6,358,573	7,321,427
CIN	66,143,914	76,159,828
CONS	43,183,494	49,722,601
CWLD	1,434,449	1,651,662
CWLP	1,969,123	2,267,299
DECO	51,796,627	59,639,987
DPC	5,555,689	6,396,966
GRE	12,206,726	14,055,142
HE	395,476	455,361
IPL	15,157,443	17,452,675
MDU	2,624,984	3,022,476
MEC	23,772,354	27,372,108
MGE	3,397,476	3,911,942
MP	10,405,799	11,981,509
MPW	874,017	1,006,366
NIPS	18,713,128	21,546,783
NSP	46,290,179	53,299,720
OTP	7,741,784	8,914,091
SIGE	7,771,825	8,948,683
SIPC	0	0
SMP	1,658,694	1,909,864
UPPC	1,125,810	1,296,287
WEC	33,353,045	38,403,566
WPS	13,993,353	16,112,312
Exports and Wheel-Throughs excluding those sinking in PJM	11,203,439	12,899,932
Total	507,884,771	584,791,771

Note:
Energy Values exclude load under Carve-Out Grandfathered Agreements. Assumes an annual energy growth rate of 1.42% consistent with the MTEP 11 Business as Usual with historic demand and energy growth rates future.

Source:
"Planning Year 2011 LOLE Study Report Section 5.2: Expected PRM for 2012-2020, available at
https://www.midwestiso.org/Library/Repository/Study/LOLE/2011%20LOLE%20Study%20Report.pdf

Table A- 6. Total RPS Wind Requirements, MISO 2020

States and Applicable Entities	2020 RPS Percent[1]	2010 Sales (MWh)[2]	Wind Capacity (GW)
Illinois			
IOUs	12%	141,166,903	5.53
Retail Suppliers	10%	56,008,018	1.75
Indiana (IOUs, Coops, Retail Suppliers)	7%	97,839,378	2.23
Michigan			
Detroit Edison[3]			0.6
Consumers Energy[3]			0.5
Munis, Coops, Retail Suppliers, other IOUs	10%	112,626,721	3.67
Missouri (IOUs)	10%	59,915,285	1.95
Minnesota			
Xcel	30%	35,868,470	3.51
Munis, Coops, Other IOUs	25%	31,109,354	2.54
Montana (IOUs, Retail Suppliers)	15%	11,597,303	0.57
North Dakota (Munis, IOUs, Coops)	10%	12,767,081	0.42
South Dakota (Munis, IOUs, Coops)	10%	10,998,704	0.36
Wisconsin (Munis, IOUs, Coops)	10%	68,752,417	2.24
Total			25.87
Currently Installed Wind Capacity			10.45
New wind capacity required			**15.42**

[1] Source: DSIREusa.org database

[2] Source: EIA Form 861-File2, 2010

[3] The RPS requirements for Detroit Edison and Consumers Energy apply to capacity, not generation.

Average MISO Wind Capacity Factor 35%

Sopurce : EIPC Input Assumptions, MRN-NEEM Business as Usual Modeling Assumptions, Appendix A, Exhibit 11 - NEEM Capacity Factors (New and Existing) and Resource Potentials

Table B-1 - Detailed Results of Economic Dispatch

#	Scenario Report			Task 3 (Base)		Task 2 (Retire Tier II, replace with gas)		Task 4 (Wind in addition to RPS) 10 GW		Task 4 (Wind in addition to RPS) 15 GW		Task 4 (Wind in addition to RPS) 20 GW	
	Capacity Requirement												
1		Peak Demand (Block B1) MW		104,475		104,475		104,475		104,475		104,475	
2		Reserve margin (%)		19%		19%		19%		19%		19%	
3		Reserve margin (MW)		124,325		124,325		124,325		124,325		124,325	
4	Total Capacity Mix (MW)	Coal Units from 2011											
5			Retrofitted	56,806	44.1%	47,613	38.2%	47,613	38.3%	47,613	38.2%	47,613	38.2%
6			Sub-total	56,806	44.1%	47,613	38.2%	47,613	38.3%	47,613	38.2%	47,613	38.2%
7		Natural Gas											
8			CT as of 2011	21,857	17.0%	21,857	17.5%	21,857	17.6%	21,857	17.5%	21,857	17.5%
9			new CT	0	0.0%	0	0.0%	0	0.0%	1,000	0.8%	1,000	0.8%
10			CC as of 2011	10,730	8.3%	10,730	8.6%	10,730	8.6%	10,730	8.6%	10,730	8.6%
11			new CC	0	0.0%	5,000	4.0%	3,500	2.8%	2,100	1.7%	1,600	1.3%
12			other gas as of 2011[A]	8,441	6.6%	8,441	6.8%	8,441	6.8%	8,441	6.8%	8,441	6.8%
13			Sub-total	41,028	31.9%	46,028	36.9%	44,528	35.8%	44,128	35.4%	43,628	35.0%
14		Wind											
15			as of 2011 (nameplate)	10,447		10,447		10,447		10,447		10,447	
16			as of 2011 (firm)	1,348	1.0%	1,348	1.1%	1,348	1.1%	1,348	1.1%	1,348	1.1%
17			new (nameplate)	15,424		15,424		25,424		30,424		35,424	
18			new (firm)	1,990	1.5%	1,990	1.6%	3,280	2.6%	3,925	3.1%	4,570	3.7%
19			Sub-total (nameplate)	25,871		25,871		35,871		40,871		45,871	
20			Sub-total (firm)	3,337	2.6%	3,337	2.7%	4,627	3.7%	5,272	4.2%	5,917	4.7%
21		Hydro		1,924	1.5%	1,924	1.5%	1,924	1.5%	1,924	1.5%	1,924	1.5%
22		Nuclear		8,531	6.6%	8,531	6.8%	8,531	6.9%	8,531	6.8%	8,531	6.8%
23		Other[B]		17,172	13.3%	17,172	13.8%	17,172	13.8%	17,172	13.8%	17,172	13.8%
24		TOTAL		128,798	100.0%	124,604	100.0%	124,394	100.0%	124,639	100.0%	124,784	100.0%
25	2020 Revenue requirement of incremental capacity costs												
26	(2010 $ Million)	Retrofitted		$3,733	79.6%	$2,763	71.1%	$2,763	62.0%	$2,763	58.3%	$2,763	54.9%
27		Wind		$954	20.4%	$954	24.6%	$1,573	35.3%	$1,882	39.7%	$2,192	43.6%
28		Gas CT		$0	0.0%	$0	0.0%	$0	0.0%	$22	0.5%	$22	0.4%
29		Gas CC		$0	0.0%	$168	4.3%	$118	2.6%	$71	1.5%	$54	1.1%
30		TOTAL		$4,687	100.0%	$3,885	100.0%	$4,454	100.0%	$4,738	100.0%	$5,031	100.0%
31	Unit 2020 Revenue requirement of incremental capacity costs (2010 $/MWh)			$8.37		$6.93		$7.95		$8.46		$8.97	
32	Generation by capacity factor (GWh)												
33		Peaking (<10% capacity factor)		8,471	1.5%	8,569	1.5%	8,716	1.6%	8,753	1.6%	8,691	1.5%
34		Intermediate and baseload		551,496	98.5%	551,708	98.5%	551,395	98.4%	551,339	98.4%	552,247	98.5%
35		TOTAL		559,967	100.0%	560,277	100.0%	560,111	100.0%	560,091	100.0%	560,938	100.0%
36	Total Generation Mix (GWh)	Coal											
37			Retrofitted	266,001	47.5%	230,317	41.1%	218,328	39.0%	216,000	38.6%	212,290	37.8%
38			Sub-total	266,001	47.5%	230,317	41.1%	218,328	39.0%	216,000	38.6%	212,290	37.8%
39		Natural Gas											
40			CT as of 2011	749	0.1%	1,404	0.3%	1,176	0.2%	1,132	0.2%	988	0.2%
41			new CT	0	0.0%	0	0.0%	0	0.0%	45	0.0%	21	0.0%
42			CC as of 2011	46,436	8.3%	44,173	7.9%	39,566	7.1%	37,848	6.8%	33,521	6.0%
43			new CC	0	0.0%	38,202	6.8%	26,742	4.8%	16,045	2.9%	12,225	2.2%
44			other gas as of 2011[A]	6,961	1.2%	6,631	1.2%	6,183	1.1%	6,163	1.1%	5,302	0.9%
45			Sub-total	54,146	9.7%	90,410	16.1%	73,666	13.2%	61,233	10.9%	52,056	9.3%
46		Wind											
47			as of 2011	33,710	6.0%	33,710	6.0%	33,710	6.0%	33,710	6.0%	33,710	6.0%
48			new	45,953	8.2%	45,953	8.2%	75,746	13.5%	90,642	16.2%	105,538	18.8%
49			Sub-total	79,663	14.2%	79,663	14.2%	109,456	19.5%	124,352	22.2%	139,249	24.8%
50		Hydro		9,412	1.7%	9,412	1.7%	9,412	1.7%	9,412	1.7%	9,412	1.7%
51		Nuclear		66,369	11.9%	66,369	11.8%	66,369	11.8%	66,369	11.8%	66,369	11.8%
52		Other[B]		84,375	15.1%	84,105	15.0%	82,880	14.8%	82,724	14.8%	81,562	14.5%
53		TOTAL		559,967	100.0%	560,277	100.0%	560,111	100.0%	560,091	100.0%	560,938	100.0%
54	Total Annual Energy Cost @ LMP (2010 $ Million)			$26,331		$26,388		$26,187		$26,131		$25,970	
55	Avg Annual LMP (2010 $/MWh)			$47.02		$47.10		$46.75		$46.66		$46.30	
56	2020 Revenue requirement of incremental capacity and capital addition costs + energy @ LMP (2010 $/MWh)			$55.39		$54.03		$54.71		$55.11		$55.27	
57	Annual natural gas consumption (000 MMBtu)			392,737		628,089		515,186		433,885		369,471	

Notes:

[A] The category "Other gas" includes capacity and generation from natural gas using steam turbines, cogeneration, or internal combustion engines.

[B] The category "Other" includes capacity and generation from units using waste heat, fuel oil, wood, other biomass, refuse, petroleum coke, kerosene, and all other miscellaneous fuels. This category also includes capacity and generation from coal-powered units excluded from the screening analysis due to cogeneration or low generation.

[C] Coal retrofits require the addition of an FGD, an SCR, a baghouse, an ACI, a closed-loop cooling system, control of combustion residuals, and control of effluent.

[D] The capital cost of converting a coal unit to a gas CC includes new gas burners and piping, widnbox modifcations, aiar heater upgrades, gas recirculating fans, control system modifcations, and lateral pipeline spur extensions.

Sources:

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Table B-1 - Detailed Results of Economic Dispatch

	Scenario Report			Task 3 (Base)	Task 2 (Retire Tier II, replace with gas)	Task 4 (Wind in addition to RPS) 10 GW	Task 4 (Wind in addition to RPS) 15 GW	Task 4 (Wind in addition to RPS) 20 GW
	Scenario Report (Block LMP)			Task 3 (Base)	Task 2 (Retire Tier II, replace with gas)	Task 4 (Wind in addition to RPS) 10 GW	Task 4 (Wind in addition to RPS) 15 GW	Task 4 (Wind in addition to RPS) 20 GW
58	Load Shape and Clearing Prices (2010 $/MWh)							
59	*Season*	*Hours*	*Block*					
60	Summer	10	B1	$72.97	$74.70	$73.14	$70.78	$68.62
61		25	B2	$72.00	$74.50	$73.14	$71.91	$69.79
62		75	B3	$66.55	$69.21	$68.22	$68.01	$67.58
63		100	B4	$61.69	$64.94	$64.90	$64.91	$64.19
64		200	B5	$55.53	$58.39	$58.32	$58.32	$57.32
65		300	B6	$51.76	$52.55	$52.42	$52.48	$52.06
66		400	B7	$48.09	$48.50	$48.28	$48.28	$48.09
67		500	B8	$46.45	$46.45	$46.26	$46.26	$46.15
68		800	B9	$45.91	$45.70	$45.53	$45.53	$45.26
69		1262	B10	$44.31	$43.97	$43.68	$43.43	$43.31
70	Shoulder	25	B11	$47.28	$47.42	$46.63	$46.45	$46.26
71		200	B12	$46.49	$46.45	$46.15	$46.06	$45.91
72		600	B13	$46.80	$46.80	$46.30	$46.29	$46.06
73		900	B14	$46.36	$46.30	$45.99	$45.91	$45.91
74		1203	B15	$45.62	$45.26	$44.87	$44.75	$44.16
75	Winter	25	B16	$48.33	$48.95	$47.52	$46.80	$46.29
76		100	B17	$47.29	$47.42	$46.45	$46.29	$46.06
77		400	B18	$46.52	$46.45	$46.06	$45.99	$45.91
78		700	B19	$45.99	$45.91	$45.64	$45.53	$45.26
79		935	B20	$44.31	$43.94	$43.20	$43.03	$42.69

Changes relative to Task 3 (Base)

	Scenario Report			Task 2 (Retire Tier II, replace with gas)		Task 4 (Wind in addition to RPS) 10 GW		Task 4 (Wind in addition to RPS) 15 GW		Task 4 (Wind in addition to RPS) 20 GW	
	Capacity Requirement										
1		Peak Demand (Block B1) MW		0	0.0%	0	0.0%	0	0.0%	0	0.0%
2		Reserve margin (%)		0%	0.0%	0%	0.0%	0%	0.0%	0%	0.0%
3		Reserve margin (MW)		0	0.0%	0	0.0%	0	0.0%	0	0.0%
4	Total Capacity Mix (MW)	Coal Units from 2011									
5			Retrofitted	-9,193	-16.2%	-9,193	-16.2%	-9,193	-16.2%	-9,193	-16.2%
6			Sub-total	-9,193	-16.2%	-9,193	-16.2%	-9,193	-16.2%	-9,193	-16.2%
7		Natural Gas									
8			CT as of 2011	0	0.0%	0	0.0%	0	0.0%	0	0.0%
9			new CT	0	0.0%	0	0.0%	1,000	0.0%	1,000	0.0%
10			CC as of 2011	0	0.0%	0	0.0%	0	0.0%	0	0.0%
11			new CC	5,000	0.0%	3,500	0.0%	2,100	0.0%	1,600	0.0%
12			other gas as of 2011[A]	0	0.0%	0	0.0%	0	0.0%	0	0.0%
13			Sub-total	5,000	12.2%	3,500	8.5%	3,100	7.6%	2,600	6.3%
14		Wind									
15			as of 2011 (nameplate)	0	0.0%	0	0.0%	0	0.0%	0	0.0%
16			as of 2011 (firm)	0	0.0%	0	0.0%	0	0.0%	0	0.0%
17			new (nameplate)	0	0.0%	10,000	64.8%	15,000	97.2%	20,000	129.7%
18			new (firm)	0	0.0%	1,290	64.8%	1,935	97.2%	2,580	129.7%
19			Sub-total (nameplate)	0	0.0%	10,000	38.7%	15,000	58.0%	20,000	77.3%
20			Sub-total (firm)	0	0.0%	1,290	38.7%	1,935	58.0%	2,580	77.3%
21		Hydro		0	0.0%	0	0.0%	0	0.0%	0	0.0%
22		Nuclear		0	0.0%	0	0.0%	0	0.0%	0	0.0%
23		Other[B]		0	0.0%	0	0.0%	0	0.0%	0	0.0%
24		TOTAL		-4,194	-3.3%	-4,404	-3.4%	-4,159	-3.2%	-4,014	-3.1%
25	2020 Revenue requirement of incremental capacity costs										
26	(2010 $ Million)	Retrofitted		-$970	-26.0%	-$970	-26.0%	-$970	-26.0%	-$970	-26.0%
27		Wind		$0	0.0%	$619	64.8%	$928	97.2%	$1,237	129.7%
28		Gas CT		$0	0.0%	$0	0.0%	$22	0.0%	$22	0.0%
29		Gas CC		$168	0.0%	$118	0.0%	$71	0.0%	$54	0.0%
30		TOTAL		-$802	-17.1%	-$234	-5.0%	$51	1.1%	$343	7.3%
31	Unit 2020 Revenue requirement of incremental capacity costs (2010 $/MWh)			-$1.44	-17.2%	-$0.42	-5.0%	$0.09	1.1%	$0.60	7.2%
32	Generation by capacity factor (GWh)										
33		Peaking (<10% capacity factor)		98	1.2%	245	2.9%	282	3.3%	220	2.6%
34		Intermediate and baseload		212	0.0%	-101	0.0%	-157	0.0%	751	0.1%
35		TOTAL		310	0.1%	144	0.0%	125	0.0%	971	0.2%
36	Total Generation Mix (GWh)	Coal									
37			Retrofitted	-35,684	-13.4%	-47,673	-17.9%	-50,000	-18.8%	-53,711	-20.2%
38			Sub-total	-35,684	-13.4%	-47,673	-17.9%	-50,000	-18.8%	-53,711	-20.2%
39		Natural Gas									
40			CT as of 2011	655	87.4%	427	57.0%	383	51.2%	239	31.9%
41			new CT	0	0.0%	0	0.0%	45	0.0%	21	0.0%
42			CC as of 2011	-2,264	-4.9%	-6,871	-14.8%	-8,588	-18.5%	-12,915	-27.8%
43			new CC	38,202	0.0%	26,742	0.0%	16,045	0.0%	12,225	0.0%
44			other gas as of 2011[A]	-330	-4.7%	-779	-11.2%	-799	-11.5%	-1,660	-23.8%
45			Sub-total	36,264	67.0%	19,519	36.0%	7,087	13.1%	-2,090	-3.9%
46		Wind									
47			as of 2011	0	0.0%	0	0.0%	0	0.0%	0	0.0%
48			new	0	0.0%	29,793	64.8%	44,689	97.2%	59,586	129.7%
49			Sub-total	0	0.0%	29,793	37.4%	44,689	56.1%	59,586	74.8%
50		Hydro		0	0.0%	0	0.0%	0	0.0%	0	0.0%
51		Nuclear		0	0.0%	0	0.0%	0	0.0%	0	0.0%
52		Other[B]		-269	-0.3%	-1,495	-1.8%	-1,651	-2.0%	-2,813	-3.3%
53		TOTAL		310	0.1%	144	0.0%	125	0.0%	971	0.2%
54	Total Annual Energy Cost @ LMP (2010 $ Million)			$56	0.2%	-$144	-0.5%	-$200	-0.8%	-$361	-1.4%
55	Avg Annual LMP (2010 $/MWh)			$0.08	0.2%	-$0.27	-0.6%	-$0.36	-0.8%	-$0.72	-1.5%
56	2020 Revenue requirement of incremental capacity and capital addition costs + energy @ LMP (2010 $/MWh)			-$1.36	-2.5%	-$0.68	-1.2%	-$0.28	-0.5%	-$0.12	-0.2%
57	Annual natural gas consumption (000 MMBtu)			235,352	59.9%	122,449	31.2%	41,148	10.5%	-23,267	-5.9%

Notes:

[A] The category "Other gas" includes capacity and generation from natural ga

[B] The category "Other" includes capacity and generation from units using wa
This category also includes capacity and generation from coal-powered units

[C] Coal retrofits require the addition of an FGD, an SCR, a baghouse, an ACI, a

[D] The capital cost of converting a coal unit to a gas CC includes new gas burn
modifcations, and lateral pipeline spur extensions.

Sources:

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Documentation Supplement for EPA Base Case v4.10_PTox – Updates for Pr
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Integrated Planning Model (IPM) – Revisions to Cost and Performance for AP
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Recent developments in the Levelized Cost of Energy from U.S. Wind Power
Ventyx EPM Simulation Ready Data, NERC Database, Release 9.1.0, February

Changes relative to Task 3 (Base)

	Scenario Report			Task 2 (Retire Tier II, replace with gas)		Task 4 (Wind in addition to RPS) 10 GW		Task 4 (Wind in addition to RPS) 15 GW		Task 4 (Wind in addition to RPS) 20 GW	
	Scenario Report (Block LMP)			Task 2 (Retire Tier II, replace with gas)		Task 4 (Wind in addition to RPS) 10 GW		Task 4 (Wind in addition to RPS) 15 GW		Task 4 (Wind in addition to RPS) 20 GW	
58	Load Shape and Clearing Prices (2010 $/MWh)										
59	*Season*	*Hours*	*Block*								
60	Summer	10	B1	$1.73	2.4%	$0.17	0.2%	-$2.19	-3.0%	-$4.35	-6.0%
61		25	B2	$2.50	3.5%	$1.14	1.6%	-$0.09	-0.1%	-$2.21	-3.1%
62		75	B3	$2.66	4.0%	$1.67	2.5%	$1.46	2.2%	$1.03	1.5%
63		100	B4	$3.25	5.3%	$3.21	5.2%	$3.22	5.2%	$2.50	4.1%
64		200	B5	$2.86	5.2%	$2.79	5.0%	$2.79	5.0%	$1.79	3.2%
65		300	B6	$0.79	1.5%	$0.66	1.3%	$0.72	1.4%	$0.30	0.6%
66		400	B7	$0.41	0.9%	$0.19	0.4%	$0.19	0.4%	$0.00	0.0%
67		500	B8	$0.00	0.0%	-$0.19	-0.4%	-$0.19	-0.4%	-$0.30	-0.6%
68		800	B9	-$0.21	-0.5%	-$0.38	-0.8%	-$0.38	-0.8%	-$0.65	-1.4%
69		1262	B10	-$0.34	-0.8%	-$0.63	-1.4%	-$0.88	-2.0%	-$1.00	-2.3%
70	Shoulder	25	B11	$0.14	0.3%	-$0.65	-1.4%	-$0.83	-1.8%	-$1.02	-2.2%
71		200	B12	-$0.04	-0.1%	-$0.34	-0.7%	-$0.43	-0.9%	-$0.58	-1.2%
72		600	B13	$0.00	0.0%	-$0.50	-1.1%	-$0.51	-1.1%	-$0.74	-1.6%
73		900	B14	-$0.06	-0.1%	-$0.37	-0.8%	-$0.45	-1.0%	-$0.45	-1.0%
74		1203	B15	-$0.36	-0.8%	-$0.75	-1.6%	-$0.87	-1.9%	-$1.46	-3.2%
75	Winter	25	B16	$0.62	1.3%	-$0.81	-1.7%	-$1.53	-3.2%	-$2.04	-4.2%
76		100	B17	$0.13	0.3%	-$0.84	-1.8%	-$1.00	-2.1%	-$1.23	-2.6%
77		400	B18	-$0.07	-0.2%	-$0.46	-1.0%	-$0.53	-1.1%	-$0.61	-1.3%
78		700	B19	-$0.08	-0.2%	-$0.35	-0.8%	-$0.46	-1.0%	-$0.73	-1.6%
79		935	B20	-$0.37	-0.8%	-$1.11	-2.5%	-$1.28	-2.9%	-$1.62	-3.7%

Appendix C. Potential Gas Market Impacts

This Attachment considers the implications of increased gas use for power generation in the MISO region on natural gas supply and gas transmission infrastructure. We address two main questions:

1) How will additional gas consumption for power generation affect wholesale natural gas prices in the MISO region?

2) Will limitations of the existing gas delivery system within the MISO region put constraints on the construction of new power plants, or the ability of existing coal units to fuel switch? If so, what new pipeline construction is likely to be needed?

Natural Gas Use for Power Generation – Existing Plants

The power plant database that was used for this study identifies 41,028 MW of gas-fired generating capacity in the MISO market as of 2011. This includes 10,730 MW of combined cycle (CC) capacity, 21,857 MW of combustion turbine (CT) capacity and 8,441 MW of other gas-fired capacity (Table C-1). The "Other" category includes steam plants and cogeneration.

If all of the existing gas-fired plants in the MISO market operated at full output, these plants could consume natural gas at a peak rate of roughly 10 Bcf per day. However, the actual peak daily gas delivery requirement for these plants is less than this because many of the gas-fired plants in the MISO market have dual-fuel capability. Based on the EIA's power plant database, we estimate that gas-fired generating units with the ability to use oil as a secondary fuel currently represent about 35 percent of the gas-fired generating capacity in the MISO market. When gas use by these dual-fuel plants is removed, the potential peak consumption of gas-only plants is reduced from 10.3 Bcf per day to 6.4 Bcf per day.

Since many of the gas-fired plants in the MISO market operate as peaking plants, average daily gas use for power generation is much lower than the maximum potential consumption. We estimate that natural gas-fired plants in the MISO market consumed approximately 275 Bcf, or 0.75 Bcf per day in 2010.

Table C-1: Base Period Generating Capacity and Natural Gas Use

	West	WI	MI	MO-IL	IN	MISO
Gas-Fired Capacity (MW)						
CC	3,583	2,498	2,416	1,349	883	10,729
CT	4,798	3,925	3,868	5,739	3,527	21,857
Other	680	856	5,461	529	917	8,442
Total	9,061	7,279	11,745	7,617	5,327	41,028
Dual-Fuel Capacity (MW)						
CC	1,533	1,316	0	0	0	2,849
CT	3,320	3,452	102	1,445	541	8,860
Other	416	386	2,218	0	0	3,020
Total	5,269	5,154	2,320	1,445	541	14,729
Potential Gas Use (Bcfd)						
Gas-Only Generating Units	0.9	0.5	2.2	1.6	1.2	6.4
Dual Fuel Generating Units	1.3	1.3	0.7	0.4	0.2	3.9
Total	2.2	1.8	2.9	2.1	1.4	10.3
Gas Use for Electric (2010)						
Annual (MMcf)	49,791	42,639	113,245	24,108	44,707	274,490
Avg. Daily (Bcfd)	0.136	0.117	0.310	0.066	0.122	0.752

Gas use for power generation is a relatively small portion of the total natural gas market in the MISO region. Table C-2 shows that although total gas consumption has declined over the last decade, and gas use for electricity has grown, electricity generation still accounts for only about 10 percent of the market. By comparison, electric generation currently accounts for more than 30 percent of total gas consumption for the United States as a whole.

Table C-2: Natural Gas Consumption in the MISO States[1] (Bcf/day)

Market Sector	2000	2005	2010
Residential & Commercial	6.2	5.9	5.6
Industrial	3.5	3.1	3.4
Electricity Generation	0.7	1.0	1.0
Other	0.4	0.4	0.3
Total	10.8	10.4	10.3

EIA

Natural Gas Use for Power Generation - Coal Retirement Cases

The implications of the coal retirement scenarios for potential peak day gas demand and annual natural gas consumption are described in Tables E-3 through E-5.

Base Case

The Base Case assumes 2,888 MW of coal plant retirements, no additions to gas-fired generating capacity, and 15.4 GW of wind additions to meet RPS requirements between 2011 and 2020. Total gas use for power generation in 2020 is projected to be 0.3 Bcf per day higher than the 2010 actuals, an increase of 43 percent.

[1] The MISO states are defined as IA, IL, IN, MI, MN, MO, ND, SD and WI.

Table C-3: Capacity Additions and Gas Use – Base Case

	West	WI	MI	MO-IL	IN	MISO
New Gas Capacity (MW)						
CC	0	0	0	0	0	0
CT	0	0	0	0	0	0
Total	0	0	0	0	0	0
Potential Gas Use (Bcfd)	2.2	1.8	2.9	2.1	1.4	10.3
Gas Use for Electricity						
Annual (MMcf)	153,702	92,875	84,307	40,667	21,186	392,737
Avg. Daily (Bcfd)	0.421	0.254	0.231	0.111	0.058	1.076
Change from 2010 (Bcfd)	0.285	0.138	(0.079)	0.045	(0.064)	0.324

High Gas Case

The High Gas Case assumes 12,081 MW of coal plant retirements, no wind additions above RPS requirements, and 5,000 MW of new CC generating capacity to meet minimum reserve margins. Potential peak gas use for power generation is 11.1 Bcf per day, which is 800 MMcf per day higher than the Base Case. Gas use for power generation is projected to reach 1.7 Bcf per day in 2020. This is a 60 percent increase from the Base Case, and a 129 percent increase from the 2010 actuals. If the same growth rate is applied to all gas-fired generation in the MISO states, and non-electric gas consumption is relatively flat, as the AEO 2012 Reference Case projects, the electric market share of total gas consumption in the High Gas Case would roughly double, from 10 percent in 2010 to 20 percent in 2020.

Table C-4: Capacity Additions and Gas Use – High Gas Case

	West	WI	MI	MO-IL	IN	MISO
New Gas Capacity (MW)						
CC	1,000	700	1,000	500	1,800	5,000
CT	0	0	0	0	0	0
Total	1,000	700	1,000	500	1,800	5,000
Potential Gas Use (Bcfd)	2.3	1.9	3.0	2.1	1.7	11.1
Change vs. Base Case (Bcfd)	0.2	0.1	0.2	0.1	0.3	0.8
Gas Use for Electricity						
Annual (MMcf)	191,366	128,353	128,912	67,696	111,762	628,089
Avg. Daily (Bcfd)	0.524	0.352	0.353	0.185	0.306	1.721
Change vs. Base Case (Bcfd)	0.103	0.097	0.122	0.074	0.248	0.645
Change from 2010 (Bcfd)	0.388	0.235	0.043	0.119	0.184	0.969

Additional Wind Cases

The Additional Wind cases add increments of wind capacity to the High Gas Case. As additional wind generation is added to the mix, the need for additional CC capacity is less, but the need for CT capacity to support wind generation increases. Potential peak gas use is lower than in the High Gas Case, but is about 0.5 Bcf per day higher than the Base Case in all of the Additional Wind scenarios.

The additional wind capacity lowers the 2020 gas use projections relative to the High Gas Case. In Scenario C, which includes 20 MW of wind generation above the RPS requirement, projected gas use for power generation falls below the Base Case projection.

Table C-5: Capacity Additions and Gas Use – Wind Cases

SCENARIO A (+ 10 GW)	**West**	**WI**	**MI**	**MO-IL**	**IN**	**MISO**
New Gas Capacity (MW)						
CC	700	500	700	300	1,300	3,500
CT	0	0	0	0	0	0
Total	700	500	700	300	1,300	3,500
Potential Gas Use (Bcfd)	2.3	1.8	3.0	2.1	1.6	10.8
Change vs. Base Case (Bcfd)	0.1	0.1	0.1	0.0	0.2	0.5
Gas Use for Electricity						
Annual (MMcf)	174,414	98,933	107,292	53,109	81,437	515,186
Avg. Daily (Bcfd)	0.478	0.271	0.294	0.146	0.223	1.411
Change vs. Base Case (Bcfd)	0.057	0.017	0.063	0.034	0.165	0.335
Change from 2010 (Bcfd)	0.341	0.154	(0.016)	0.079	0.101	0.659

SCENARIO B (+ 15 GW)	West	WI	MI	MO-IL	IN	MISO
New Gas Capacity (MW)						
CC	300	300	500	300	700	2,100
CT	200	200	200	200	200	1,000
Total	500	500	700	500	900	3,100
Potential Gas Use (Bcfd)	2.3	1.9	3.0	2.1	1.5	10.8
Change vs. Base Case (Bcfd)	0.1	0.1	0.1	0.1	0.2	0.6
Gas Use for Electricity						
Annual (MMcf)	150,444	86,980	96,057	48,521	51,884	433,885
Avg. Daily (Bcfd)	0.412	0.238	0.263	0.133	0.142	1.189
Change vs. Base Case (Bcfd)	(0.009)	(0.016)	0.032	0.022	0.084	0.113
Change from 2010 (Bcfd)	0.276	0.121	(0.047)	0.067	0.020	0.437

SCENARIO C (+ 20 GW)	West	WI	MI	MO-IL	IN	MISO
New Gas Capacity (MW)						
CC	300	300	400	0	600	1,600
CT	200	200	200	200	200	1,000
Total	500	500	600	200	800	2,600
Potential Gas Use (Bcfd)	2.3	1.9	3.0	2.1	1.5	10.8
Change vs. Base Case (Bcfd)	0.1	0.1	0.1	0.0	0.1	0.5
Gas Use for Electricity						
Annual (MMcf)	136,832	80,986	77,557	31,759	42,336	369,471
Avg. Daily (Bcfd)	0.375	0.222	0.212	0.087	0.116	1.012
Change vs. Base Case (Bcfd)	(0.046)	(0.033)	(0.018)	(0.024)	0.058	(0.064)
Change from 2010 (Bcfd)	0.238	0.105	(0.098)	0.021	(0.006)	0.260

Implications of Increased Natural Gas Use – Wholesale Natural Gas Prices

The wholesale price of natural gas can be split into two pieces: (1) the Henry Hub benchmark price, which is an indicator of changes in natural gas prices at the national level, and (2) the difference between the national reference price and the regional market price, often referred to as the "basis". For example, for the 2011 calendar year the average Henry Hub price was $3.99 per MMBtu and the average Chicago Citygate price was $4.11 per MMBtu. The Chicago market basis was $0.12 per MMBtu. We consider the implications of higher natural gas use for power generation for each of these price components separately.

Henry Hub Price

The effect of an increase in gas consumption on the market price will depend to a large degree on the price elasticity of supply. With a steep supply curve, an increase in demand will generally cause a relatively large increase in price. If the supply curve is relatively flat, the price change will be smaller (all else equal). Two recent studies examined the potential impact of increased natural gas demand on natural gas prices at the national level, as measured by the Henry Hub spot price. We use the results from these studies as guidelines to assess whether the change in gas use for power generation resulting from the coal plant retirement modeling would be expected to cause an increase in the Henry Hub price relative to the AEO 2012 Reference Case forecast.

Estimates of the effects of incremental additions in natural gas demand on the Henry Hub reference price are shown on the table below. The EIA study reports the change relative to the Henry Hub forecast in the AEO 2011 Reference Case while the Navigant study reports the change relative to the Henry Hub price forecast in Navigant's Spring 2011 Forecast. Both studies assume that additional gas demands are phased in over the period 2016 through 2020. The 2020 prices therefore show the short-term impact on natural gas prices while the 2030 prices show the longer-term implications. The Navigant analysis shows a greater short-term and long-term sensitivity of gas prices to increased demand than does the EIA.

Table C-6: Sensitivity of Henry Hub Price to Increased Demand for Natural Gas

Study	Additional Demand (Bcfd)	Percentage Change in Henry Hub Price	
		2020	2030
Navigant[2]	1.0	5.7%	4.1%
	4.4	17.5%	7.7%
EIA[3]	6.0	13.7%	8.0%

To assess how coal plant retirements in the MISO region are likely to affect gas prices for the year 2020, we first need to account for the growth in gas use for power generation that is already factored into the AEO 2012 Reference Case price forecast. As shown in Table C-7, EIA projects that gas use for electricity generation in the West North Central and East North Central census regions will increase by roughly 30 percent from 2010 to 2020.[4] We therefore subtract 30 percent of the 2010 gas use of plants in the MISO market, or 0.225 Bcf per day, to calculate the incremental gas use for the MISO market. This is shown in Table C-8.

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[2] Navigant Consulting, "North America Gas System Model to 2040", September 2011 (filed with the Department of Energy by Dominion Cove Point LNG in Docket 11-128-LNG). Table 1. *Cove Point* and A*ggregate Demand* scenarios.

[3] EIA, "Effect of Increased Natural Gas Exports on Domestic Energy Markets", January 2012. Data from Table 13 in workbooks *EIA, AEO2011 NEMS ref2011.d020911a* and *EIA, AEO2011 NEMS rfexrpd.d090911a.*

[4] The WNC and ENC census regions include the MISO states, plus KS, NE, and OH.

Table C-7: EIA Gas Consumption Forecast by Customer Class (Quads)

	Customer Class	2010	2020	Change
West North Central	Res. & Commercial	1.48	1.52	2.7%
	Electric Generation	0.13	0.08	-38.5%
	Total	1.61	1.60	-0.6%
East North Central	Res. & Commercial	3.26	3.28	0.6%
	Electric Generation	0.33	0.52	57.6%
	Total	3.59	3.80	5.8%
WNC + ENC	Res. & Commercial	4.74	4.80	1.3%
	Electric Generation	0.46	0.60	30.4%
	Total	5.20	5.40	3.8%

EIA, AEO 2012 Reference Case

Table C-8: Incremental MISO Gas Use for Electric Generation

	Electric Generation Gas Use (MMcf)	Change from 2010 (Bcfd)	Incremental Demand (Bcfd)
Base Case	392,737	0.324	0.099
High Gas Case	628,089	0.969	0.744
Wind (+10 GW)	515,186	0.659	0.434
Wind (+15 GW)	433,855	0.437	0.212
Wind (+20 GW)	369,471	0.260	0.035

Under the High Gas Case, the incremental gas demand for electricity generation in the MISO region is estimated to be 0.744 Bcf per day. Based on the Navigant and EIA results, it is possible that the change in MISO market gas use of this magnitude would be large enough to cause a measurable increase in the Henry Hub gas price, at least in the short term. The short-term increase in price is likely to be small, in the range of 2 to 4 percent. Since the incremental gas use for electricity generation in the other cases is closer to the growth in demand that is already included in the AEO 2012 Reference Case forecast, there is less reason to expect that these cases would lead to an additional change in the Henry Hub gas price.

MISO Region Price Basis

The regional gas price basis is affected by variable transportation costs and constraints on pipeline deliveries into the area. Pipeline delivery capacity into the MISO region is discussed below. Based on our assessment of currently-available gas transmission capacity and expected market developments, we do not expect that the additional gas use for power generation identified in this report would change the price basis at the major trading hubs located within the MISO region. However, it is possible that a large increase in gas use could put upward pressure on gas prices in local areas where existing gas transmission capacity is relatively tight, particularly during periods of high gas demand.

Implications of Increased Natural Gas Use – Delivery Infrastructure

Additional gas-fired generating capacity affects the natural gas delivery system at three levels of infrastructure. First, if an increase in gas use for power generation leads to a significant increase in total gas consumption, additional inter-regional pipeline capacity may be required to bring more gas into the MISO region.

Second, even if there is sufficient gas delivery capacity entering the MISO region, it may be necessary to upgrade pipeline facilities within the region to transport gas to specific locations where gas use for electricity generation has increased. The need for intra-regional gas transmission facilities will largely depend on where new gas-fired generating plants are located relative to major gas transmission lines. There should also be less need for additional intra-regional pipeline capacity if new plants are able to switch to alternate fuels during periods of peak gas demand.

Finally, pipeline and metering facilities must be constructed connect new plants to the natural gas transmission grid. These plant-specific facilities are typically designed to supply the plant's maximum hourly gas use. Gas interconnection facilities may be constructed and operated by an interstate pipeline company, a local gas distribution company, or the plant operator.

Existing Gas Transmission Capacity into the MISO Region

Natural gas is transported into the MISO Region from three main gas-producing areas: (1) the Gulf Coast (Texas, Louisiana); (2) the Rockies/Midcontinent area (Wyoming, Colorado, Oklahoma); and (3) Western Canada (Alberta, British Columbia). EIA estimates the total capacity of the natural gas pipelines entering the MISO Region to be approximately 25 Bcf per day. Pipeline capacity into the region expanded between 2000 and 2010, as large producer-driven projects that were built to transport gas through the Upper Midwest to markets in Eastern Canada and the Northeast U.S. (Table C-9). Two projects are particularly significant:

Table C-9: Natural Gas Pipeline Capacity into the MISO Region (Bcfd)

	2000	2010
Gulf Coast	8.1	7.8
Rockies/Midcontinent	6.8	8.7
Western Canada	8.0	9.1
Total	22.9	25.6

EIA, “U.S. State-to-State Capacity”

- The Alliance Pipeline, which began operating in late 2000, expanded gas transmission capacity into the MISO region from Western Canada. Alliance currently transports 1.6 Bcf per day from British Columbia and Alberta to Chicago. A companion project, the Vector Pipeline, moves gas from Chicago to the Dawn Hub in southwestern Ontario.
- The Rockies Express (REX) pipeline extends from Colorado and Wyoming to the Ohio/Pennsylvania border. REX, which has a capacity of 1.8 Bcf per day, was completed in 2009. The REX pipeline connects with markets in Missouri, Illinois and Indiana, and provides an additional source of natural gas for north-south pipelines that were originally constructed to move gas from the Gulf Coast to the Upper Midwest.

As west-to-east gas transmission capacity has expanded, the flow of gas into the MISO region from the Rockies area has increased, while deliveries from the Gulf Coast area have declined. Annual gas deliveries into the MISO region from all areas grew by 17 percent from 2000 to 2010. However, since total natural gas use within the MISO region has remained relatively flat, exports from the MISO region to Ontario and Ohio increased by roughly the same amount.

Table C-10: Natural Gas Entering and Leaving the MISO Region (Bcfd)

	2000	2010
Gulf Coast	4.4	4.2
Rockies/Midcontinent	3.8	5.8
Western Canada	5.0	5.4
Total Inflow	13.2	15.4
Ontario	1.5	2.8
Ohio	2.1	2.7
Total Outflow	3.6	5.5
Net	9.6	9.9

EIA, "Interstate Movements and Movements Across U.S. Borders of Natural Gas by State"

The difference between the total pipeline capacity entering the MISO region and the average daily gas deliveries into the MISO region includes pipeline capacity that is used during the peak winter season to deliver gas into the Upper Midwest from production-area natural gas storage facilities. It also includes some amount of surplus annual pipeline capacity that could be used to support additional gas-fired generating capacity, although the availability of surplus capacity will vary from pipeline to pipeline.[5] .

Gas Transmission Capacity into the MISO Region – Outlook through 2020

The current outlook is for strong growth in natural gas supply. The AEO 2012 Reference Case forecast projects that U.S. natural gas production will increase by 16 percent from 2010 to 2020. Other analysts are predicting even higher growth rates for both production and consumption (Table C-11).

[5] See EnVision Energy Solutions, "Gas and Electric Infrastructure Interdependency Analysis", February 22, 2012. This report, prepared for the MISO, concludes that there is generally sufficient pipeline capacity in the MISO region to provide incremental firm transportation services for power generators. However, six pipelines were found to have insufficient capacity, and two additional pipelines were identified as "questionable" (p. 96).

Table C-11: Natural Gas Supply and Demand Forecasts

	2010	2020 Forecasts		
	Actual	AEO 2012	Navigant	ICF
U.S. Production (Bcfd)	59.3	68.9	70.6	75.3
Net Imports	7.1	1.0	3.1	5.2
Total Consumption	66.1	69.8	73.4	79.2
Electric Sector Gas Use	20.2	21.6	29.7	29.6
Henry Hub Price ($2010)	4.39	4.58	4.98	5.59

EIA, AEO 2012 Reference Case

Navigant Consulting, "North America Gas System Model to 2040", September 2011

INGAA, "North American Midstream Infrastructure through 2035", June 2011 (ICF Forecast)

Strong growth in natural gas production is expected to cause significant shifts in natural gas flow patterns throughout North America. These changes are expected to have positive implications for gas delivery capacity into the MISO Region.

- Growth in Marcellus and Utica shale production in Pennsylvania and Ohio will allow west-to-east pipeline capacity that is currently used to transport gas to Northeast U.S. markets to be redirected to supply markets in Midwest. If shale gas production continues to grow, the REX pipeline owners are considering reversing the direction of gas on the eastern end of the pipeline, which would further expand gas delivery capacity into the MISO Region.[6]
- The growth in Northeast gas production is also expected to reduce gas flows from the Midwest region into Eastern Ontario for domestic consumption and for re-export to New York and New England. A recent TransCanada PipeLines forecast shows deliveries from Michigan to Ontario declining from 2.8 Bcf per day in 2010 to 2.1 to 2.2 Bcf per day in 2020.[7] This drop in exports would free up capacity on Great Lakes Gas Transmission and Vector Pipeline that could be used to supply incremental gas demands in Minnesota and Michigan.
- Further increases in Rockies gas production would support additional supply-driven pipeline projects. Wood Mackenzie, for example, projects that new pipeline capacity connecting the Rockies to the Chicago market could come on line by 2018.[8]

Based on the currently availability of pipeline capacity, and anticipated shifts in gas flows through the region, it is reasonable to expect that sufficient inter-regional pipeline capacity will be available to support increased gas use for power generation in the MISO region.

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[6] Kinder Morgan 2012 Analyst Conference, January 2012.
[7] TCPL 2012-2013 Tolls Application, Appendix C1: Throughput Study, October 31, 2011.
[8] Wood Mackenzie presentation at the Vector Pipeline Customer Meeting, October 2011.

Gas Transmission Capacity within the MISO Region

The natural gas pipelines that operate in the MISO region include major long-haul pipelines that transport gas from outside the region to major market “hubs”, such as Chicago and Detroit; pipelines that transport gas into the MISO Region, but also supply downstream markets (e.g. Great Lakes Gas Transmission, Texas Eastern, and Rockies Express); and regional pipelines that transport gas from market hubs to local markets (e.g. Guardian Pipeline). Some pipelines, such as Northern Natural Gas, which is a major supplier to Minnesota and Iowa markets, combine a long-haul mainline system with a network of smaller diameter delivery lines within the market area.

Some amount of investment in intra-regional gas transmission capacity will be necessary to support additional gas use for power generation within the MISO region. For example, a recent study sponsored by the MISO found that most pipelines in the region have insufficient capacity to supply a large increase in gas use by existing gas-fired plants and the gas requirements of new CC and CT plants that could be built under a 12.6 GW coal-to-gas retirement scenario.[9] How much the new pipeline capacity will be needed will depend to a large extent on where the new gas-fired capacity is located. Generally speaking, the opportunities to tap directly into available capacity on major long-haul pipelines will be greater in Illinois and Indiana, where multiple pipelines cross the area, than in areas such as Minnesota or western Wisconsin, which are supplied primarily by smaller-diameter branch lines that were constructed specifically to serve these markets. The need for additional intra-regional pipeline capacity will also depend on whether new plants have dual-fuel capability, or are only able to operate on natural gas.

While new facilities will be required, intra-regional pipeline capacity is not likely to be a constraint on increasing of gas-fired generating in the MISO region. As the author of a recent Congressional Research Service study that looked potential increases in generation at existing gas-fired power plants observed, “given sufficient lead time, the natural gas industry has the ability to install large amounts of additional transportation capacity to meet increased demand”.[10] Pipelines routinely expand market-area capacity to supply market growth or provide access to new sources of natural gas. Recent intra-regional projects that have been undertaken by pipelines in the MISO region to serve electric and non-electric gas requirements are summarized in Table C-12.

[9] EnVision Energy Solutions, “Embedded Natural Gas-Fired Electric Power Generation Infrastructure Analysis: An Analysis of Daily Pipeline Capacity Availability”, July 6, 2012.

[10] Congressional Research Service, “Displacing Coal with Generation from Existing Natural Gas-Fired Power Plants”, January 19, 2010.

Table C- 12: Recent Pipeline Expansion Projects within the MISO Region

Pipeline (FERC Docket)	Project	Incremental Delivery Capacity	Facilities	Cost
Guardian Pipeline (CP07-8)	G-II Expansion	537,200 Dth/day	119.2 of new pipe; 78K HP compression	$261 million
ANR Pipeline (CP08-465)	2009 Wisconsin Expansion	97,880 Dth/day	8.9 mi. of 30-in. pipeline loop	$32 million
Northern Natural (CP09-11)	2009-2010 Zone EF Expansion	136,042 Dth/day	Pipeline loop; 15K HP compression	$126 million
ANR Pipeline (CP11-539)	Marshfield Reduction Project	101,135 Dth/day	6.3K HP compression	$25 million

Company filings with the Federal Energy Regulatory Commission

Gas Interconnection Facilities

Plant interconnection costs depend on the size of the generating facility, but are also greatly affected by the plant's location relative to existing high-pressure pipelines. New large-scale generating plants are often built in close proximity to a major gas transmission line, and are supplied through a dedicated pipeline lateral. However, where the plant site is further from existing pipelines, or is embedded in a local gas distribution system, more extensive facilities may be needed to supply the quantities gas required, at adequate delivery pressures.

Table C-13 shows actual gas interconnection costs for the new large gas-fired generating plants that have been built in Ontario within the last five years to support the province's coal replacement policy. Interconnection costs for these plants range from $4.6 million for a plant located beside a major pipeline in a rural area, to $42.5 million for a plant located near downtown Toronto. The total gas interconnection cost for the 4,430 MW of new CC and CT plants that have been built in Ontario since 2008 is approximately $150 million.

The High Gas Case requires 5,000 MW of additional combined-cycle generating capacity. Based on the Ontario experience, we estimate that gas interconnection costs for 5,000 MW of new gas-fired capacity would be approximately $175 million. This cost could be lower if new gas-fired capacity can be located at existing generating sites with access to gas transmission lines.[11]

[11] For example, Calpine has told Minnesota regulators that it could add 345 MW of capacity to its existing Mankato Energy Center using the existing natural gas infrastructure (MPUC Docket E002/CN-11-184).

Table C-13: Gas Interconnection Costs for New Ontario Generating Plants

Generating Plant	Capacity (MW)	Plant Type	Gas Use (MMcfd)	Interconnection Facilities	Cost ($Million)	Start Date
Greenfield Energy Centre	1,005	CC	193	1.2 mi. of 16-in. lateral	$4.6	2008
Portlands Energy Centre	550	CC	98	4.0 mi. of pipeline loop; 1.8 mi. of new pipeline	$42.5	2009
Goreway Station	860	CC	153	4.0 mi. of 24-in. lateral	$21.9	2009
St. Clair Power	635	CC	96	2.8 mi. of pipeline loop; 1.8 mi. of new pipeline	$10.6	2009
Halton Hills Generating Station	680	CC	100	2.9 mi. of 20-in. pipeline	$21.3	2010
Thorold Cogeneration	265	Cogen	72	1.8 mi. of 12-in. lateral	$9.5	2010
York Energy Centre	435	CT	115	10.4 mi. of 16-in lateral	$38.9	2012
Total	4,430		827		$149.3	

Company filings with the Ontario Energy Board