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1. Introduction

These comments were prepared for the Iowa Office of Consumer Advocate ("OCA") by Synapse Energy Economics ("Synapse") to address the responses of MidAmerican Energy Company ("MidAmerican") and Interstate Power and Light Company ("IPL") to the Iowa Utilities Board's ("the Board") September 2011 notice of inquiry regarding "the potential impacts of U.S. Environmental Protection Agency regulations on coal-fired generation in Iowa." (Docket No. NOI-2011-0003).

Synapse's comments address the extent to which MidAmerican and IPL sufficiently responded to the questions set out in the Board's notice of inquiry ("NOI"). Our comments are organized as follows. First, we identify areas in the utility filings where relevant information is needed or not up-to-date. Second, we provide an assessment of the strategies presented by the utilities to comply with the EPA regulations. Third, we describe relevant analyses performed in other states and regions to identify "best practices" that could be applied in Iowa. We note that the Board has "undertaken an abbreviated review of existing studies…concerning the impact of the new EPA regulations on coal plants and ratepayers," and that these studies did not provide the level of detail and specificity required by the Board. Therefore, we have focused our comments in this section on identifying "best practice" processes and analyses that could be applied in Iowa to assess impacts, instead of the results of these studies in general. Finally, we provide specific recommendations for analysis of EPA regulations in Iowa. These recommendations support the Board's intent, as described in the NOI, to:

- Assess the possible impact of these [EPA] regulations on Iowa utilities;
- Ensure a thorough consideration of the various alternatives by the utilities and the affected parties;
- Provide the parties and the Board the background information necessary for expeditious and informed consideration of proposals to implement strategies responding to the new rules; and
- Provide policymakers with specific details and compliance scenarios to assist them in making any necessary decisions regarding coal-fired (and other) generation that serves Iowa customers.

2. Overview of Utility Filings

A. IOU Unit and Emissions Data

i. MidAmerican

MidAmerican's responses to the questions posed by the Iowa Utilities Board's Notice of Inquiry (NOI) are missing certain important data. In particular, the Company's filings lack sufficient detail to determine whether or not the utility's underlying assumptions are reasonable, and whether or not the compliance strategies presented do in fact lead to emissions reductions sufficient to fulfill its obligations under upcoming EPA regulations.[1]

The first request in the Board's NOI asks MidAmerican to provide a list of its coal plants, including the technology of each such plant, and its emissions. Table 1, below, presents data from MidAmerican's response to this request, along with data from the company's 2010 Emissions Planning and Budget Filing. Included in Table 1 is information on MidAmerican's coal-fired generating units, currently installed emissions control technologies, approved future control technologies, and emissions allowances under the EPA's Cross-States Air Pollution Rule for NO_x and SO_2.

Table 1. MidAmerican Coal-Fired Generating Units, Emissions Control Technologies, and Emissions Allocations under EPA's CSAPR

Unit Name	Operation Date	Capacity (MW)	Existing Environmental Controls	Approved Environmental Controls	2010 NOx Emissions	NOx - 2012 CSAPR Allocation	NOx - 2014 CSAPR Allocation	2010 SO2 Emissions	SO2 - 2012 CSAPR Allocation	SO2 - 2014 CSAPR Allocation
Neal North Unit 1	1964	140	Neural network, OFA, hot ESP		2,594	947	925	3,062	2,808	1,944
Neal North Unit 2	1972	294	Neural network, LNB, OFA, cool ESP		2,470	1,781	1,738	6,689	5,277	3,653
Neal North Unit 3	1975	522	Neural network, LNB, OFA, cool ESP	{[redacted]}	4,434	3,483	3,400	11,911	10,322	7,145
Neal South Unit 4	1979	645	Neural network, LNB, OFA, cool ESP	{[redacted]}	5,754	4,354	4,250	16,575	12,904	8,933
Walter Scott Unit 1	1954	38	LNB, hot ESP		607	396	386	1,346	1,173	812
Walter Scott Unit 2	1958	84	LNB, OFA, hot ESP		476	599	585	2,374	1,777	1,230
Walter Scott Unit 3	1978	710	Neural network, LNB, OFA, cold ESP, dry scrubber, baghouse		5,411	4,821	4,706	8,723	14,288	9,891
Walter Scott Unit 4	2007	811	Neural network, LNB, OFA, dry scrubber, baghouse, SCR, ACI		1,405	1,625	1,625	2,129	2,132	2,132
Louisa Unit 101	1983	750	Neural network, LNB, OFA, hot ESP, dry scrubber, baghouse		4,745	4,397	4,292	7,075	13,031	9,021
Riverside Unit 5	1961	133	Neural network, LNB, OFA, cold ESP		900	708	692	3,014	2,100	1,453

[1] Synapse understands that OCA has the ability to obtain data from the utilities, but that OCA did not request this information because the utilities are not seeking approval of specific compliance options in this proceeding and because it is likely that the underlying data and assumptions will change between now and when the utilities do seek specific approval of a compliance strategy or long-term resource proposal.

NOTE: Confidential material has been identified by placing it between curly brackets { }.

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{[redacted]}[2] The first compliance deadline for emissions reductions under CSAPR occurs in 2012. As shown in Table 1, the majority of MidAmerican's units exceed the 2012 CSAPR emissions allocations. For example, with the currently installed NO_x controls, only Walter Scott Units 2 and 4 currently fall below the allocated number of NO_x allowances for CSAPR in 2012, using the 2010 emissions provided by MidAmerican in its response to the Board. With currently installed SO_2 controls, only Walter Scott Units 3 and 4, and the Louisa Generating Station fall below the allocated SO_2 allowances under CSAPR for 2012.

With so few units currently emitting less than the 2012 allocations for NO_x and SO_2, and with the first compliance deadline nearly upon us, the Company has very limited options to comply with the emissions limits; they can either generate less electricity over the course of the year and thus produce a lower amount of emissions, or purchase emissions allowances in the market. Neither of these strategies has been evaluated in MidAmerican's responses to the Board, nor has the utility stated how it plans to comply with the 2012 allowance allocations under CSAPR.

{[redacted]}[3] {[redacted]}[4] {[redacted]}

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[2] MidAmerican Energy Company. *Environmental Plan and Budget Confidential Exhibit 1 Update for 2010* .Docket No. EPB-2010-0156. February 15, 2011.

[3] MidAmerican Energy Company. *Electric Power Generation Facility Budget Update for January 1, 2010 through December 31, 2019.* Docket No. EPB-2010-0156. April 1, 2010.

[4] MidAmerican Energy Company. *Electric Power Generation Facility Budget Update for January 1, 2010 through December 31, 2019.* Docket No. EPB-2010-0156. September 17, 2010.

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ii. IPL

The output used by IPL comes from past models, and is not likely to be up-to-date. If IPL is using data that is no longer current, the strategies described in Section 3 below may not comply with EPA regulations. If they do comply, estimated costs of compliance may be very far off from actual compliance costs.

In its filing to the Board, IPL stated that it is premature to address the utility's compliance plan in this response; however, the first compliance deadline for CSAPR occurs in 2012, and IPL must be prepared to meet that deadline. While these responses need not represent IPL's completed plan, they should indicate that IPL is currently progressing toward compliance with the EPA's emissions regulations.

In response to the first request in the Board's NOI, IPL provided a list of its coal-fired generating units and their capacities, currently installed emissions control technologies, and actual 2010 emissions. Table 2 replicates this information and includes additional variables. Online dates were taken from the 2010 EIA Form 860, and emission allowances under the EPA's Cross-States Air Pollution Rule for NO_x and SO_2 were taken from the EPA's CSAPR website.[5]

[5] See *Final CSAPR Unit Level Allocations under the FIR and Underlying Data*. EPA website. Available at: http://www.epa.gov/airtransport/techinfo.html

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Table 2. IPL Coal-Fired Generating Units, Emissions Control Technologies, and Emissions Allocations under EPA's CSAPR

Unit Name	Operation Date	Capacity (MW)	Existing Environmental Controls	Approved Environmental Controls	2010 NOx Emissions	NOx - 2012 CSAPR Allocation	NOx - 2014 CSAPR Allocation	2010 SO2 Emissions	SO2 - 2012 CSAPR Allocation	SO2 - 2014 CSAPR Allocation
Burlington Unit 1	1968	212	CESP, flue gas conditioning, LNB, OFA, low sulfur coal		718	1,244	1,244	2,890	3,883	2,688
Dubuque Unit 6		13.8	CESP, low sulfur coal		24	36	25	11	12	12
Dubuque Unit 5		31.7	CESP, low sulfur coal		306	160	157	268	475	329
Dubuque Unit 1		37	CESP, low sulfur coal		489	203	199	504	603	417
Lansing Unit 3	1957	35.8	CESP		0	177	173	0	525	364
Lansing Unit 4	1977	270	HESP, flue gas conditioning, LNB, SCR, low sulfur coal, baghouse, ACI	Scrubber	1,611	1,561	1,524	4,729	4,627	3,203
ML Kapp Unit 2	1967	235.8	CESP, flue gas conditioning, LNB, OFA, low sulfur coal		540	997	973	3,462	2,955	2,045
Ottumwa Unit 1	1981	727	HESP, flue gas conditioning, LNB, OFA, low sulfur coal	Scrubber, baghouse, ACI	3,382	4,346	4,243	13,461	12,881	8,917
Prairie Creek Unit 1	1997	16	CESP, low sulfur coal		381			659		
Prairie Creek Unit 2	1951	23	CESP, low sulfur coal		428			539		
Prairie Creek Unit 3	1958	50	CESP, flue gas conditioning, OFA, low sulfur coal		631	321	313	1,132	950	658
Prairie Creek Unit 4	1967	149	CESP, flue gas conditioning, LNB, OFA, low sulfur coal		1,503	728	711	2,424	2,158	1,494
Sutherland Unit 1	1955	37.5	CESP, LNB, low sulfur coal		417	281	274	890	832	576
Sutherland Unit 3	1961	96	CESP, OFA, RRI/SNCR, low sulfur coal		826	558	545	4,285	1,655	1,146

Of the units generating electricity in 2010 (it appears that Lansing Unit 3 did not), only Burlington Unit 1 and Dubuque Unit 6 are currently in compliance with the EPA's 2012 CSAPR emissions limits for both NO_x and SO_2. Ottumwa and ML Kapp are in compliance with NO_x regulations for 2012, but not SO_2. Conversely, Dubuque Units 1 and 5 are in compliance with SO_2 regulations for 2012, but not NO_x.

Installation of the approved scrubber, baghouse, and ACI will likely bring the Ottumwa unit into compliance with both CSAPR and the Mercury and Air Toxics Standards (MATS) rules. Installation of the approved scrubber at Lansing Unit 4 will bring the unit into compliance with SO_2 regulations.

Engineering and design for these projects is currently underway, and they are expected to be put into service in 2014.[6]

As noted above, IPL has failed to describe how it plans to bring the remainder of its generating units into compliance with the 2012 CSAPR allowance allocations; it has stated that it is premature to address the utility's compliance plan in its response to the Board's NOI.

B. Assessment of Strategies Presented by IOUs

Below we discuss the compliance strategies presented by MidAmerican and IPL in response to the Board's NOI. It is noteworthy that neither company has examined a compliance strategy that includes additional energy efficiency, demand response, rate structures, or purchased power. In addition to the issues specific to each company, which are discussed below, we strongly recommend that both companies examine additional sensitivity cases to include these resource options as part of a compliance strategy. Doing so could greatly affect the relative economics of compliance strategies; for example, as the operating costs of existing coal units or replacement natural gas units increase, causing energy prices to rise, larger amounts of energy efficiency become cost-effective. Use of greater amounts of energy efficiency and, in particular, inclusion of all cost-effective energy efficiency and demand response, may help to bring energy prices back down as they displace higher-cost marginal generating resources. Time-of-use and real-time pricing for large customer should also be evaluated as policy options.

i. MidAmerican

As part of the determination of a pollution compliance strategy, MidAmerican examined five scenarios in its responses to the Board's questions:

1. Business-as-usual (BAU)
2. Add a gas-fired, combined-cycle combustion turbine
3. Upgrade all coal plants to meet the new rules
4. Replace all coal units with gas
5. Replace some or all coal units with nuclear units

Of these five scenarios, three may be impractical to implement. While provided in the Board's NOI as "possible strategies" to address the EPA rules, scenarios 3 and 4 are primarily all-or-nothing scenarios, with one upgrading all coal units and another replacing all coal units with gas. MidAmerican stated that these two scenarios may be impractical and costly. The Company also states that the nuclear replacement scenario (scenario 5) would be impossible in the next decade.

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[6] Interstate Power and Light Company. *Interstate Power and Light Company's Periodic Report*. Docket No. EPB-2010-0150. October 3, 2011.

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The utility thus evaluates only two scenarios that it might be realistic to implement. MidAmerican states that in each of these scenarios – the BAU scenario and new combined-cycle scenario – emissions of SO_2 are well below the CSAPR allowance allocation by 2015. Emissions of NO_x are also expected to be below the emissions allocation, with the exception of the BAU case in the timeframe of 2017-2021.[7] The scenario that adds a combined-cycle unit not only complies with EPA regulations, but also seems to offer the most flexibility and fuel diversity, as it includes a combination of coal retrofits, retirements and fuel switching.

While MidAmerican shows the new combined-cycle scenario being more costly than the BAU scenario, it is unclear which of these two scenarios might actually be the least-cost compliance scenario (or if there might be another least-cost scenario), as MidAmerican would likely have to incur additional costs to bring the BAU scenario into compliance with NOx regulations from 2017 to 2021. In Section 5, we provide recommendations of other relevant resource options that should be considered, as well as criteria for the development of reasonable scenarios.

MidAmerican's preferred strategy for compliance with EPA regulations seems to focus on {[redacted]}[8] MidAmerican {[redacted]} response to Iowa Utilities Board Question 3, stating that

> Additions of emissions controls to other smaller and older plants, Walter Scott Jr. Energy Center Unit 1 (a 45 MW unit placed in-service in 1954), Walter Scott Jr. Energy Center Unit 2 (an 88 MW unit placed in-service in 1958) and Riverside Generating Station Unit 5 (a 130 MW unit placed in-service in 1961) are considered impractical based on their size, remaining life and cost of environmental retrofits.[9]

The Neal North Units 1 and 2, {[redacted]} should be evaluated carefully. Both units are less than 300 MW and are 47 and 39 years old, respectively. Neal Unit 1 is able to burn natural gas without further modification and may be needed for reliability. If Neal Unit 1 is converted to natural gas, Neal Unit 2 seems likely to be retired.

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[7] *MidAmerican Energy Company Response to Question No. 7.* Filed with the State of Iowa, Department of Commerce, Utilities Board. Docket No. NOI-2011-0003. November 3, 2011.

[8] *Review of Emissions Plan and Settlement Agreement.* MidAmerican Energy Company, Docket No. EPB-2010-0156. Memo from Brenda Biddle to the Iowa Utilities Board. January 27, 2010. Page 11.

[9] *MidAmerican Energy Company Response to Question No. 3.* Filed with the State of Iowa, Department of Commerce, Utilities Board. Docket No. NOI-2011-0003. November 3, 2011.

PUBLIC

However, the units may be able to share emission control equipment, lowering the costs of emissions control retrofits.[10]

MidAmerican has not included water, effluent, and coal ash regulations in the strategies analyzed in this NOI filing. The Company states that the Neal Energy Center, Walter Scott, Jr. Energy Center and Riverside units may be impacted by the 316(b) rules, but does not do an analysis of the ability or cost to comply with this rule. It is unclear how coal ash rules might affect the utility.

ii. IPL

In the past, IPL's emissions compliance scenarios have used banking or the purchase of SO_2 and NO_x allowances to meet a portion of the regulations under the CAIR program, as seen in IPL's 2010 Emissions Planning and Budget filings. These emissions allowances cannot be used for compliance under CSAPR, and the rule limits the amount of emissions trading allowed to meet compliance requirements through the use of enforceable state emissions caps.

IPL has thus outlined its compliance strategy going forward as reliance on emissions control retrofit projects at its existing coal units to a large extent, and to other compliance options and alternatives to a lesser extent. IPL states in its 2010 Emissions Plan and Budget that it is not practical or cost effective to build new generating units to replace the existing coal fleet, when compared to retrofitting those coal units with emissions control equipment:

> For larger, base-load coal-fired generating units, retrofitting the units by installing emission controls will typically be a more practical, lower cost alternative versus replacing the capacity and energy provided by these units with capacity and energy from newly-constructed units. For smaller, intermediate-load coal-fired generating units, IPL may consider fuel switching or replacement with capacity and energy from new generating units in the course of conducting its integrated resource planning process.[11]

IPL is concentrating its emissions control investments on two of its larger units—Ottumwa and Lansing 4, which will allow the Company "to maintain flexibility to change the operations of other IPL coal-fired units to support compliance with emerging environmental rules and regulations, including those related to GHG emissions, without exposing IPL and its customers to potential stranded investment at units where these changes occur."[12]

These strategies are evident in the three scenarios IPL presented to the Board in its November 3 filing, in which the utility grouped its units into three tiers. Tier 1 units are expected to get full emissions

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[10] *Id.*

[11] Interstate Power and Light Company. *Emissions Budget Update: 2011-2015.* Docket No. EPB-2010-0150. April 1, 2010. Pages 38-39.

[12] Direct Testimony of Eric J. Guelker, Manager-Environmental Services Planning at IPL. State of Iowa. Before the Iowa Utilities Board. Interstate Power and Light Company. Docket No. EPB-2010-0150. April 1, 2010. Page 13.

controls, and include Ottumwa and Lansing Unit 4. Tier 2 units may receive low-cost controls, but are not likely to receive full controls, and Tier 3 units are not likely to receive any additional emissions controls.

The three strategies presented by IPL include:

1. Business-as-usual (BAU)
2. Tier 1 Incremental and Tier 2 Controlled
3. Tier 1 Incremental and Tier 2 Retired

While the BAU scenario takes the steps of retrofitting Ottumwa and Lansing 4 with the approved emissions controls listed in Table 2, and retiring the less-efficient Tier 3 units, this scenario does not incorporate any strategies to comply with the MATS and Clean Air Visibility Rule (CAVR), or with water, effluent, and ash rules. This scenario is therefore not fully in compliance with EPA regulations. It also includes some elements that may not be cost-effective. For example, Dubuque Units 3 and 4 are converted to natural gas effective January 1, 2012, but are retired three years later on January 1, 2015. Public Service Company of Colorado proposed a similar strategy (discussed later in these comments), requesting to install SNCR technology on one of its units and subsequently retiring that unit. The Public Service Commission of Colorado denied this request, and asked that the utility retire the unit outright.

In contrast, the second and third scenarios examined by IPL do comply with the MATS rule, and take steps to comply with ash and water rules. In the second scenario, the Tier 2 units receive emissions retrofits, but could be converted to natural gas or retired if environmental rules are more stringent. IPL identifies Sutherland 3 as a good candidate for natural gas conversion. This scenario seems to provide the most flexibility, leaving IPL with several options for emissions compliance from Tier 2 units. The utility should, however, perform and provide an analysis comparing the costs of retrofitting, retiring, and converting each of these Tier 2 units under its base and sensitivity assumptions as a means of examining the relative economics of each option under a variety of possible outcomes. In the third scenario, Tier 2 units are retired. IPL did not indicate whether replacement capacity would be needed under the second or third scenario. This consideration would be especially important under the third scenario, as the Tier 2 units are all retired by 2015.

C. Sensitivity Variables

i. MidAmerican

The sensitivity values presented by MidAmerican do not represent the full range of possibilities that should be considered. Evaluation of realistic sensitivity cases can help determine which compliance scenario presents the least amount of risk to MidAmerican. For its sensitivity analyses, MidAmerican considered cases with high natural gas prices, high carbon prices, no load growth for 10 years, delayed implementation of the MATS rule, and lower construction costs for the combined-cycle unit. Additional variables to be analyzed in sensitivity scenarios should include low natural gas prices, higher construction costs for the combined-cycle unit, and low and high emissions control technology capital costs. Changes in these variables may have an important effect on MidAmerican's compliance plan as a whole, and particularly on units that may be marginal, such as Neal Energy Center Units 1 and 2.

Also, as the economics of (and the trade-offs between) retrofitting, retiring, and fuel-switching vary significantly with the price of natural gas, it is important that MidAmerican evaluate its scenarios with viable base, low, and high natural gas prices. In presenting its high natural gas price, the Company presents only a percentage difference from the original value. Because the original value is not given in this filing, it is difficult to determine whether the sensitivity value is reasonable.

It is also important to include a price for emissions of CO_2, both in the base case and as a sensitivity case, as it can dramatically impact the economics of coal units. Implementation of a CO_2 price is likely to occur near the end of the decade. Climate talks in early December in Durban, South Africa resulted in an agreement between nations to create a new climate change treaty by 2015 that would require the United States, China, and all other major greenhouse gas emitters to begin reducing their emissions.[13] MidAmerican's base and high CO_2 price forecasts provide reasonable estimates of a starting year for CO_2 regulation, the beginning allowance price, and the annual escalation of those prices.

ii. IPL

In its response to the Board, IPL considers eight different sensitivity cases, which present varying fuel prices, loads, and CO_2 prices. IPL's price forecasts for coal and natural gas come from its 2010 Integrated Resource Plan. Fuel prices have changed since then, with natural gas in particular being much lower now than in 2010. IPL should use updated fuel prices in its base set of inputs and vary its sensitivity cases using revised price forecasts. For the reasons mentioned above regarding the climate agreement in Durban, IPL should include a set of CO_2 prices in its base set of inputs. The utility can then examine high and low CO_2 price scenarios. IPL's decision to renew its PPA at the DAEC nuclear power plant is integral to IPL's long-term resource plans and environmental compliance strategies, and therefore, should also be evaluated under these criteria. Like MidAmerican, IPL should also consider variability of natural-gas replacement capacity cost and emissions retrofit technology costs. Sensitivity cases using high and low capital cost values for emissions control technologies are especially important under IPL's second scenario, where Tier 2 units may be retrofit, retired, or converted to natural gas.

As additional sensitivity cases, both IPL and MidAmerican should examine additional energy efficiency, demand response, renewable energy and combined heat and power (CHP) opportunities, rate structures and purchased power as part of a compliance strategy. As operating costs of existing coal units or replacement natural gas units cause energy prices to rise, the amount of cost-effective energy efficiency increases. Use of greater amounts of energy efficiency and, in particular, inclusion of all cost-effective energy efficiency and demand response may help to bring energy prices back down as they displace higher cost marginal generating resources. Time of use and real time pricing for large customer should also be evaluated as policy options.

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[13] Holly, Chris. *Deal Reached to Launch New Talks on Binding Climate Pact*. Energy Daily. December 11, 2011.

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3. Regional and State Examples

This section focuses on processes being developed and analyses being conducted in other states and regions that may be applicable to Iowa as it moves forward in its assessment of EPA impacts and various compliance scenarios. Included in this section is key information regarding:

- MISO analyses examining the regional impacts of utility sector rules;
- The State of Minnesota's collaborative approach with the EPA, and its process of modeling compliance with environmental regulations for the state as a whole;
- Public Service Company of Colorado's progress toward full implementation of an emissions reduction plan; and
- Different methods of compliance developed by utilities in Kentucky and Georgia in direct response to the EPA regulations.

MISO

Three-Phase Modeling Analysis

MISO performed a three-phase modeling analysis of the impact of proposed EPA regulations on the generating units in the MISO territory from a regional perspective. In the first phase, MISO used the EGEAS model to screen the 2,000 units in its system to determine which of those would be the most at risk for retirement. Annual revenues and costs for each of the units were calculated in order to determine net profit margins. The units with margins of $0/kW or less were considered to be at-risk or potentially at-risk units. More at-risk units are identified when high compliance costs are paired with lower gas prices. The addition of a carbon price leads to an even greater number of at-risk units.

In the second phase, the results of the screening analysis were used to determine any energy and congestion impacts on the system with the PROMOD IV production cost model and the PSS/E transmission adequacy model. Models were utilized to determine if transmission congestion could supply revenues to generators that would be sufficient to remove their at-risk designations. Results showed that more than 3,500 MW might be located in areas sensitive to transmission congestion.

In the third phase, MISO developed compliance and capital cost requirements, and examined resource adequacy, system reliability, and impact on customer rates. In the third phase, MISO used all three of the previously mentioned models, as well as GE-MARS, a resource adequacy model. Modeling in EGEAS compared two model runs for every unit – the first run placed emissions controls on the unit and the second retired the unit and replaced it with natural gas capacity. The lowest cost solution determined the strategy for the unit. Model outputs were used as inputs into the additional models

Evaluation of Six Scenarios

MISO examined six scenarios. Four scenarios included each of the EPA regulations independently, one included a combination of all four regulations, and one did not include any new regulations. MISO then modeled a variety of sensitivity cases for each of these scenarios, analyzing both high and expected capital costs for emissions control technologies, gas prices of $4.50, $6.00, $8.00 and $10.00 per MMBtu, and CO_2 emissions prices of $0, $10, and $100 per ton. MISO states that "Although carbon is not currently regulated, prudence dictates that it be considered in the evaluation of the proposed EPA regulations."[14] More than 400 EGEAS cases were run in this modeling analysis.

Results

Results showed that 2,919 MW of coal capacity are at-risk for retirement under all scenarios. There are 12,652 MW of coal capacity at-risk for retirement "identified to be within prudence considerations and error bounds for the assumptions of the MISO study."[15] MISO expects that the higher value of retirements is the more likely scenario. Net present value of capital cost of compliance for the 20-year time period analyzed is estimated to be $31.6 billion for the scenario in which 2,919 MW are retired and $33.0 billion for the scenario in which 12,652 MW are retired. (Values are in 2011 dollars in this study.) Reliability of the MISO system as a whole might actually improve with a greater number of retirements, as older, less reliable units are replaced.

PROMOD modeling showed that energy costs will increase as units are retired. Some low-cost coal units will be retired. Coal units retrofit with emissions controls will experience losses in efficiency and will therefore be more expensive to operate. Natural gas units with higher operating costs will come online as replacement units. The combination of these factors will lead to higher production costs for energy. The expected cost increase is approximately $1/MWh when 2,919 MW of capacity are retired, and $5/MWh when 12,652 MW are retired. This translates to retail rate increases of 7.0-7.6%. The addition of a price on CO_2 would lead to cost increases of $30/MWh, and even higher retail rates.

Transmission upgrades would be required in each of the scenarios. Total investments under the lower retirement scenario would be approximately $580 million, and upgrades would require $880 million of investment under the higher retirement scenario. Certain of these transmission upgrades would not be able to be completed by the date units would need to retire to be in compliance with EPA regulations, and these units may need to make arrangements to continue to operate until the lines could be completed.

MISO makes the caveat that its retirement results are extremely sensitive to natural gas and carbon prices, and possibly the interactions of these two variables. Generation owners must consider many factors when making decisions to retrofit or retire coal units, which include the costs of: retrofits, replacement capacity, transmission upgrades, transmission congestion, compliance timelines, and regulatory uncertainty.

Timing for Compliance Options

Timing for compliance options is one risk highlighted by MISO in its study. It states that construction of a replacement combustion turbine would take two to three years, and new transmission lines would require a minimum of five years to be operational. Replacement capacity would need to be permitted as

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[14] Midwest ISO, *EPA Impact Analysis: Impacts from the EPA Regulations on MISO*, October 2011, p. 17. Available at: https://www.midwestiso.org/Library/Repository/Study/MISO%20EPA%20Impact%20Analysis.pdf
[15] *Id.* Page 32.

soon as possible in order to come into operation before compliance deadlines, and transmission lines not already under consideration will likely not be put into service until after 2015-2016 deadlines. Additionally, MISO mentions the sequencing of unit outages for retrofits as a significant risk factor. It states that "Given the tight window for compliance, much of the capacity on the MISO system will need to take their maintenance outages concurrently. The need to take multiple units out of service on extended outage has significant potential to impact resource adequacy."[16]

Surveying Generators

MISO is now surveying its members regarding EPA compliance plans. Actual plans of generators and load serving entities are presumably more informative than model based estimates. MISO has asked that the utilities respond to a series of questions about each of the EPA regulations:

- CSAPR – MISO has asked about specific approaches that will be utilities relative to emissions limits (higher offer prices, seasonal operation, reduction in offered capacity, etc.) and for detailed timelines on implementation schedules that will be utilized to meet CSAPR, including when planned outages will occur and their duration
- MATS – MISO has asked what actions the utility plans to take to comply with the Rule (emissions control retrofits, retirements, others); for a detailed description of expected installed emissions control equipment, the resulting emissions output, lead time for construction of equipment, and expected unit outages; and for a list of unit retirements and dates, the types of supply-side and demand-side resources that will be used as replacement capacity and anticipated online dates, information on capacity purchases, if planned, and impacts of water and ash rules on the decision to retire.

Minnesota

Minnesota agencies are taking a collaborative approach to planning for compliance with upcoming utility sector regulations. As parties in the Power Sector Regulations Project, the Minnesota Public Utilities Commission, Minnesota Pollution Control Agency, and Minnesota Department of Commerce have partnered with the US EPA to gather information and create tools that will help the state develop a plan to meet environmental rules in a coordinated and cost-effective way.[17] Minnesota is the only state so far that the EPA has partnered with to conduct this type of analysis.

Minnesota agencies view the collaboration as a means by which they can have an influence on federal policy. They will work with EPA to develop input assumptions, and EPA will use the Integrated Planning Model (IPM), a multi-region model of the US electric power sector, to perform analysis of environmental regulations. The modeling effort will examine compliance costs and attempt to determine if they can be reduced through integrated control strategies, multi-pollutant strategies, and deployment of energy efficiency, combined heat and power (CHP), and low-emitting renewable resources. EPA will also

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[16] *Id.* Page 7.
[17] Minnesota Pollution Control Agency website. *Power Sector Regulations Project*. Accessed December 5, 2011. Available at: http://www.pca.state.mn.us/index.php/air/air-permits-and-rules/air-rulemaking/power-sector-regulations-project.html

provide technical support, examining reliability issues, estimating air quality benefits and costs of GHG emissions, and studying impacts of utility sector rules on employment in Minnesota.

A number of concerns have been raised by the Minnesota agencies that they hope to address through the project with the EPA. One of these relates to timing and cost of upcoming regulations, with the agencies suggesting that due to the timing of the regulations, there may be a sudden increase in demand for resources and skilled workers that will end up increasing the costs for each. Additionally, entities reiterate the fact that plants cannot be removed from service at the same time due to reliability concerns. The agencies want to emphasize energy efficiency, as it is typically the cheapest form of "generation," and question how biomass will be treated as a compliance option from a greenhouse gas emissions standpoint. The Minnesota agencies also want to understand how energy efficiency, demand response and demand-side management can be treated in modeling efforts and in the deliberations around compliance options. Compliance options should be flexible, and modeling should reflect that Minnesota is part of the larger MISO market, meaning that the lowest cost compliance option may be through purchased power from other regions. [18]

Ultimately, the Minnesota agencies plan to provide a series of recommendations for a process or plan that will guide owners of coal-generating capacity toward a compliance strategy that meets all environmental regulations while ensuring reliability, lowering costs, and incorporating energy efficiency, CHP and renewable energy sources. The agencies want to develop an estimate of the effect of this compliance strategy on air quality in the state, and to quantify cost and rate impacts for citizens of Minnesota.[19]

The pilot project is reaching its end. Modeling analysis was performed by EPA over the month of November. The various agencies and EPA have had several meetings to discuss results over the first half of the month of December. The group is planning to meet in person during the week of December 17 to discuss modeling results and finalize the stakeholder recommendations.

Colorado

In April 2010, the Clean Air-Clean Jobs Act was signed into law by Colorado governor Bill Ritter. The law required a coordinated plan for emissions reductions from owners or operators of coal-fired power plants that "will enable Colorado rate-regulated utilities to meet the requirements of the federal Clean Air Act and protect public health and the environment at a lower cost than a piecemeal approach."[20] Emissions reduction plans must apply to a minimum of 900 MW or 50% of the utility's coal-fired capacity, whichever is less. Plans cannot apply to any capacity that is marked for retirement by January 1, 2015. NO_x emissions must be reduced by 70-80% below 2017, and the Public Service Company of Colorado (PSCo) was required to examine, but not necessarily to implement, the impacts of repowering

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[18] *Id.*

[19] Minnesota Pollution Control Agency, *Pilot Project on Rules for Minnesota's Power Sector: Project Overview and Participant Input*. Saint Paul, MN, August 19, 2011.

[20] State of Colorado, House of Representatives, *House Bill 10-1365*, 67th General Assembly, 2010. Available at: http://www.leg.state.co.us/clics/clics2010a/csl.nsf/fsbillcont3/0CA296732C8CEF4D872576E400641B74?open&file=1365_enr.pdf

PUBLIC

900 MW of coal generation. The Clean Air-Clean Jobs Act supports energy efficiency resources and the replacement or repowering of coal generation with natural gas or other low-emitting resources. Replacements or repowering should be accomplished with reasonable rate impacts as compared to the installation of emissions controls on coal-fired units.

The Colorado Public Utilities Commission (PUC) opened the docket to examine PSCo's emissions reduction plan on May 7, 2010. Immediately after the docket was opened, parties began petitioning the PUC for intervenor status , which the PUC officially granted to 35 different parties. The emissions reductions plan submitted by PSCo to the PUC used the STRATEGIST capacity expansion model to analyze nine possible scenarios with different replacement generation portfolios. PSCo's benchmark scenario kept all coal-fired generating capacity in service but retrofitted the units with necessary emissions control technologies. Another scenario replaced almost all coal-fired capacity with natural gas units. The remaining scenarios examined different combinations of emission controls, replacement gas capacity, and fuel switching. "Bolt-on" options were examined that included the impacts of additional DSM, low emitting generation technologies like solar and wind, and certain IPP facilities.[21]

The preferred plan submitted by PSCo retired 903 MW of coal generation, and included fuel-switching from coal to gas, conversion of some units from boilers to synchronous condensers, construction of new combined-cycle gas-fired units, and retrofits with emissions controls on certain coal-fired units. These actions were estimated to reduce NO_x emissions by almost 90%, SO_2 emissions by 84%, CO_2 emissions by 51%, and mercury emissions by 85%. The plan would require generation construction investment of $1.3 billion.[22]

There were several important concerns in this docket, but the most important was reliability, both in specific areas and across all of PSCo's territory. Two coal-fired generating stations, Arapahoe and Cherokee, were considered by PSCo to be integral to reliability in the Denver metropolitan area, with transmission system operators relying on power generation and voltage support from these plants. With seventeen transmission lines running from the Cherokee plant to the Denver area, it was decided by PSCo that there needed to be new generation constructed at the Cherokee site to replace coal units, and that it should be natural gas-fired. One new combined-cycle unit was proposed for the site, as well as the conversion of Cherokee Unit 3 from coal to natural gas, and the conversion of Unit 2 to a

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[21] Direct Testimony and Exhibits of James F. Hill on behalf of Public Service Company of Colorado, Before the Public Utilities Commission of the State of Colorado in the Matter of Commission Consideration of Public Service Company of Colorado Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act," Docket No 10M-245E, August 13, 2010.

[22] Direct Testimony and Exhibits of Karen T. Hyde on behalf of Public Service Company of Colorado. Before the Public Utilities Commission of the State of Colorado in the Matter of Commission Consideration of Public Service Company of Colorado Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act," Docket No 10M-245E, August 13, 2010.

synchronous condenser for system stability. Synchronous condenser and natural gas conversions were also proposed for Arapahoe Units 3 and 4, respectively.[23]

PSCo was also concerned about maintaining its reserve margin over its entire service territory. The company had to sequence planned outages, upgrades, replacements and retirements in order to maintain its reserve margin over its system and over the compliance time period. This sequencing was also done in order to keep electric rates affordable.[24]

As mentioned above, this docket had 35 official intervenors, which included representatives from the coal and natural gas industries, independent power producers, environmental groups, and large industrial and retail customers. More than 1,800 documents were submitted by the various parties in this case. PSCo held a modeling workshop to help intervenors understand modeling inputs and to accept feedback; nevertheless, when PSCo submitted its scenarios to the PUC, intervenors criticized the narrow range and suggested that data were not sufficient for them to participate in the process. Had the PUC established criteria for the model inputs and outputs to be shared with intervenors, many of these criticisms could have been avoided. This is discussed further in the Recommendations section later in these comments. The PUC itself criticized cost estimates made by PSCo, suggesting that cost estimates for SCR retrofits seemed high, while estimates for construction of new combined-cycle natural gas plants seemed too low.[25]

In a total of eighteen hearings, the PUC examined PSCo's emissions reduction plan, competing plans offered by various intervenors, and forecasts of coal, gas and carbon dioxide prices. The Commission ultimately approved a plan that differed from PSCo's proposed plan, requiring installation of emissions control technologies earlier on two units, requiring the retirement of Cherokee Unit 3 two years earlier than proposed, and requiring the conversion to natural gas of Cherokee Unit 4 by 2017 rather than installing SCR and running the plant through 2022. The PUC also acknowledged the need for gas transportation infrastructure in the form of a new gas pipeline, and approved a long-term contract for natural gas with Anadarko.[26] The approved plan is expected to result in a rate increase of 2.5%.

The issues covered in this docket are likely to come up in other states as utilities present strategies for compliance with EPA's CSAPR, MATS, ash and 316(b) rules. In this docket, it was a less expensive strategy to install pollution control retrofits in the majority of the scenarios examined by PSCo. The Clean Air-Clean Jobs Act provided explicit support for replacement of natural-gas capacity and

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[23] Direct Testimony and Exhibits of Teresa M. Mogensen on behalf of Public Service Company of Colorado. Before the Public Utilities Commission of the State of Colorado in the Matter of Commission Consideration of Public Service Company of Colorado Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act," Docket No 10M-245E, August 13, 2010.
[24] Karen T. Hyde, op. cit.
[25] Harris Group, Inc., *Independent Engineer's Report: Review of House Bill 10-1365 and Emission Reduction Plan Filed by Public Service Company of Colorado.* Prepared for the Public Utilities Commission Department of Regulatory Agencies State of Colorado, Docket No 10M-245E, September 17, 2010.
[26] Colorado Public Utilities Commission. *Final Order Addressing Emission Reduction Plan*. Before the Public Utilities Commission of the State of Colorado in the Matter of Commission Consideration of Public Service Company of Colorado Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act." Docket No 10M-245E. December 15, 2010.

repowering alternatives, and without this law, it is unlikely that the PUC could have approved the large volume of fuel-switching and replacement capacity due to the fact that these were not the lowest cost emissions reduction option.

Kentucky

Beginning in May 2010, Kentucky Utilities (KU) and Louisville Gas & Electric (LG&E) began working with engineering firm Black and Veatch to develop unit by unit compliance options for the EPA's utility sector rules. After the optimal control technologies were selected, a schedule for implementation was developed for each of the units, and conceptual designs and budgetary cost estimates for emissions control technologies were created.[27]

The generation planners at KU and LG&E (the Companies) then performed an analysis on an aggregate basis to determine if all of the unit by unit compliance equipment would be necessary to comply with environmental regulations. This analysis allowed the Companies to eliminate certain control options, specifically SCRs, which were previously included in each unit retrofit project. Air compliance projects were evaluated on a grouped-unit or single unit basis, depending on the configuration of the control technologies. The generation planners at the Companies then examined, on a unit by unit basis, if it would be more cost effective to install the necessary emission controls or to retire the unit and buy replacement power of generation. The Companies made two assumptions when doing their analysis: first, that the only options for the units were to operate in compliance with environmental regulations or to retire, and second, that the proposed set of environmental controls from Black and Veatch was the most cost-effective set of controls for the unit.

When considering unit retirement options, a least-cost resource expansion plan was developed to replace the retired capacity using the STRATEGIST model, with the expectation that the replacement generation is a natural gas-fired combined-cycle combustion turbine. Projects that were recommended to proceed were those that had the lowest Present Value Revenue Requirements (PVRR) over the 30 year study period. PVRR included capital investments – either the environmental control costs or the costs of replacement generation – and project O&M costs.[28] Units with higher variable operating costs were evaluated first, and if the revenue requirements of retiring and replacing capacity of a given unit are lower than the revenue requirements of installing emissions controls, that unit is assumed to be retired when the next unit is evaluated. This method creates more realistic circumstances under which to evaluate each unit.[29]

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[27] *Environmental Air Compliance Strategy Summary for Kentucky Utilities Company and Louisville Gas and Electric Company*, May 2011.
[28] Direct Testimony of Charles R. Schram, Commonwealth of Kentucky , Before the Public Service Commission, In the Matter of: *The Application of Louisville Gas & Electric Company for Certificates of Public Convenience and Necessity and Approval of its 2011 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2011-00162, June 1, 2011.
[29] Louisville Gas & Electric and Kentucky Utilities Generation Planning and Analysis, *2011 Air Compliance Plan*, May 2011.

PUBLIC

The resulting least-cost plan for compliance with environmental regulation requires installation of emissions controls on the Brown, Ghent, Mill Creek, and Trimble County 1 coal units. The Green River, Tyrone, and Cane Run 4-5 units are retired in the analysis. The difference in PVRR between installation of emissions controls and retirement for the Cane Run 6 unit is $8 million, which is within the Companies margin of error, and is also recommended for retirement. The total capital cost for these projects is $2,458 million.[30]

Louisville Gas & Electric filed testimony with the Public Service Commission of Kentucky on June 1, 2011 requesting approval for these pollution control retrofits on the above-mentioned units. Immediately prior to scheduled PUC hearings, the Companies settled with the intervenors in the case, agreeing to defer the planned construction of a baghouse for mercury control on Brown Units 1 and 2. The Companies may resubmit their request after July 1, 2013, unless EPA rules establish new requirements for the units. The baghouse project was estimated to cost $225 million. The Companies are allowed to proceed with environmental cost recovery on the remaining $2.25 billion in emissions control retrofit investments.[31]

Georgia

Georgia Power submitted several requests to the Georgia Public Service Commission on August 4, 2011. One of those requests was for the approval of Georgia Power's Updated Integrated Resource Plan for 2010, which outlined the company's analysis of EPA regulations and its preferred compliance strategy. Additional requests include decertification for the Branch 1 and 2 units, approval of 1,562 MW of purchased-power agreements, and approval of $3 billion for baghouse controls on specific units.

In its compliance analysis, Georgia Power evaluated only those units for which it has not already incurred significant expenditures for installed emissions controls. Plants Bowen, Wansley, Scherer, and Hammond were therefore not evaluated, as these are larger coal units already equipped with environmental controls. These units are assumed to be available in 2015, operating with the baghouse controls requested for rate recovery, above.

A set of necessary environmental controls was determined for each of the remaining units. The incremental cost of the unit with emissions controls was compared to a proxy estimate of site-specific replacement combined-cycle capacity cost. Included in this evaluation were hourly production cost modeling using PROSYM and any transmission system costs. Some of the units would not be able to be controlled in time to meet the 2015 MATS compliance deadline, and an additional analysis was done for these units allowing them an extra year for compliance.

Based on the results of its analysis, the Company is deferring the decision to retrofit, retire, or fuel-switch the following units: Branch 3 and 4, Yates 1, Yates 2-5, Yates 6 and 7, Mitchell 3, Kraft 1-4, McIntosh 1 and McManus 1 and 2, for a total of 2,592 MW deferred. Georgia Power believes it can make more informed decisions regarding the status of these units after the environmental rules are

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[30] *Id.*

[31] Sarah Tavangar, "Kentucky utilities in settlement to control coal plant emissions," *Electric Power Daily*, November 11, 2011. Available at: http://www.plattsenergyweektv.com/story.aspx?storyid=174431&catid=293.

PUBLIC

finalized, particularly the MATS rule, which is the key driver influencing the timing of decisions about the deferred units. Georgia power is assuming, however, that approximately 600 MW of capacity that is currently deferred will be controlled by 2015. Approximately 2,000 MW of capacity, then, is expected to be unavailable in 2015, due to the fact that these units are less likely to be controlled based on economics, or cannot be controlled by the compliance deadline for the MATS rule and will therefore be unavailable to generate.

The Company believes that it is highly unlikely that required environmental retrofits could be completed by 2015, and Georgia Power proposed to procure enough capacity to maintain reliability in 2015 and beyond. The Company calculated the capacity deficit in 2015 to be approximately 1,200 MW. To meet this need, Georgia Power requested PSC approval of 1,562 MW of purchased-power agreements (PPAs). Four PPAs contribute to this 1,562 MW of capacity, and they range in length from twelve years and seven months to fifteen years and five months.[32] The PSC conducted hearings on the various Georgia Power requests in early December.

4. Recommendations

In this section we present recommendations specific to MidAmerican and to IPL, and then provide process recommendations applicable to both companies.

A. MidAmerican

In light of the findings described in previous sections, Synapse recommends that in connection with any proposed environmental compliance strategy the Board require MidAmerican, at minimum, to:

- Describe how it plans to comply with the 2012 allowance allocations under the EPA's Cross-States Air Pollution Rule for SO_2 and NO_x;
- Examine additional scenarios that may be practical to implement, including a compliance strategy that includes additional energy efficiency, renewable energy and CHP, demand response, rate structures, or purchased power;
- Ensure that compliance with coal ash, water and effluent regulations is analyzed and included in future scenarios;
- Provide the bases values for all sensitivity variables considered to enable an evaluation of whether its high and low sensitivity values are reasonable; and
- Consider variability of natural-gas replacement capacity cost, and emissions retrofit technology costs.

[32] Georgia Power Company, *Georgia Power Company's Application for Decertification of Plant Branch Units 1 & 2 and Mitchell Unit 4C, Application for Certification of the Power Purchase Agreements with BE Alabama LLC from the Tenaska Lindsay Hill Generating Station and with Southern Power Company from Harris, West Georgia and Dahlberg Electric Generating Plans and Updated Integrated Resource Plan,* Docket No. 34218, August 4, 2011.

PUBLIC

B. IPL

In light of the findings described in previous sections, Synapse recommends that in connection with any proposed environmental compliance strategy the Board require IPL, at minimum, to:

- Use up-to-date data, instead of output from past models. In particular, use updated fuel prices in its base set of inputs and vary its sensitivity cases using revised price forecasts;
- Indicate how the company is currently progressing toward compliance with EPA's emissions regulations, particularly for 2012;
- Analyze a sensitivity scenario that does not include the retirement of Dubuque Units 3 and 4 just three years after converting them to natural gas;
- Revise the second scenario to provide an analysis comparing the costs of retrofitting, retiring, and converting each of the Tier 2 units under IPL's base and sensitivity assumptions, as a means of examining the relative economics of each option under a variety of possible outcomes;
- Indicate whether replacement capacity would be needed under the second or third scenario;
- Examine additional scenarios that may be practical to implement, including a compliance strategy that includes additional energy efficiency, renewable energy and CHP, demand response, rate structures, or purchased power;
- Include a set of CO_2 prices in its base set of inputs, and examine high and low CO_2 price scenarios;
- Evaluate the option of PPA extension at DAEC; and
- Consider variability of natural-gas replacement capacity cost, and emissions retrofit technology costs.

C. Process Recommendations

As electric utilities plan for EPA environmental regulations, utility commissions play an important role in shaping utility compliance plans. In Colorado, for example, the PUC made changes to the timing and types of control installations proposed by PSCo in its Final Order.

The process by which utility commissions evaluate compliance plans is important, as well. The Iowa Utilities Board is urged to establish a comprehensive and consistent process for considering utility proposals for major investments in existing generating units. In general, we recommend that the Board's final guidelines should require: a thorough inventory and description of all relevant resource options, as well as an assessment of costs, benefits, uncertainties and risks; an objective sensitivity analysis of how those uncertainties and risks affect the various resource plans considered; and the development of a plan consisting of a portfolio of resources that delivers the lowest life cycle cost, and manages risk and uncertainty to a reasonable level over a full range of plausible future scenarios. Specific recommendations for utility analysis of EPA regulations are included here.

PUBLIC

i. Relevant resource options

An appropriate emissions compliance strategy considers all resources that may contribute to meeting need. Energy efficiency and demand response (together, demand-side management) resources, transmission and distribution resources (including improvements to transmission and distribution efficiency), CHP and renewable energy resources, and all other types of generating resources must be considered on an equal basis. The plan should be an integrated portfolio of resources with the mix of resources that will provide adequate and reliable service at the lowest life-cycle cost.

As discussed in the example of Minnesota, energy efficiency should be the "first fuel" considered when determining a compliance strategy, as it is often the cheapest resource. In its modeling, Minnesota is examining two energy efficiency sensitivity scenarios in addition to its base case assumptions. Low-emitting resources, such as renewable energy resources, should also be considered in compliance plans. Minnesota is interested in examining these generating technologies in its compliance planning, and the MISO analysis has stated that increased wind resources tend to lower energy costs, making coal retirements more favorable than retrofits with emission control technologies. For similar reasons, options for demand response and time of use or real time pricing should be considered for large customers.

As seen in the cases of Colorado, Kentucky, and Georgia, typical compliance strategies consist of installation of pollution control equipment, fuel-switching at existing facilities, repowering of existing units, and additions of new gas capacity. These approaches are generally similar to compliances strategies modeled by Iowa's investor-owned electric utilities. These resources should be included in future compliance plans by other utilities. As in the case of Kentucky, where compliance could be achieved by installing one emissions control technology on multiple units, cases where units can share a technology should be considered.

The Minnesota agencies point out that utilities are part of a larger market, and the least-cost compliance option may come in the form of purchased power. This was the case in Georgia, where the utility found it most cost-effective to secure more than 1,500 MW of capacity and generation as it deferred making a decision on whether to retire or retrofit its owned coal units.

ii. Use of up-to-date forecasts

Input assumptions are very important in determining which units are retrofit and which are retired in these compliance analyses, and use of up-to-date forecasts are critical. Current forecasts should be used for load, coal and natural gas prices, costs of emissions controls, costs of new capacity, cost of transmission, etc. In performing its modeling, MISO stated that it used low demand and energy growth, low gas prices, and a variety of carbon prices but that "Retirement impacts can change with different assumptions for these variables."[33] The Minnesota agencies expressed concern that as demand for control technologies and labor increased, prices would rise. In Kentucky, it was stated that it was best to move quickly with compliance strategies, as "locking in contracts and construction schedules in the near future should help to ensure that the necessary construction management, labor, and materials will be

[33] Midwest ISO, *EPA Impact Analysis: Impacts from the EPA Regulations on MISO*, October 2011, p. 3.

available to achieve timely compliance, and should help to mitigate materials and labor cost increases that could come with increased demand."[34] Effects of cost increases (due to compliance with EPA rules) on load and energy consumption should be factored into forecasts to creation of stranded environmental upgrade costs.

iii. Development of reasonable scenarios

Compliance scenarios modeled or analyzed by utilities should be both individually feasible and jointly comprehensive, and each should achieve the emissions reductions required by environmental regulations. In the case of Colorado, the Clean Air-Clean Jobs Act required that PSCo examine two specific scenarios – retrofitting all of its coal units with emissions control technologies and replacement of all coal units with natural-gas fired capacity. PSCo went on to develop seven more scenarios that it modeled in developing its compliance plan, which included a variety of retirement, retrofit, repowering and construction options.

Scenarios need not be mandated by state law nor be determined solely by the evaluating utility. State utility commissions may also specify scenarios that utilities should examine. The Minnesota Public Service Commission, for example, specifies that utilities must evaluate resource plans using low, medium and high values for CO_2 allowance prices.

These reasonable assumptions should be consistently evaluated in all long-term resource planning contexts, such as energy efficiency plans, emissions planning budgets, new resource plans/acquisitions, PURPA avoided cost determinations etc.

iv. Rigorous analysis of reasonable sensitivity scenarios

A resource plan that is projected to have the lowest life cycle cost under one set of assumptions about the future, may or may not also be the best under another set of assumptions. Assumptions that can make a material difference to the performance of resource plans include, but are not limited to, (1) load growth and other factors affecting the size and timing of resource needs over time, such as trends in customer types, end use make up and load shape, (2) cost, availability and deliverability of fuels, equipment, construction materials and expertise, labor, land, transmission service and other goods and services that determine the cost of the various resources in the portfolio, (3) financial factors, such as inflation rates, utility bond ratings and changes in the rating criteria, cost and availability of various types of insurance, cost and availability of various types of capital, (4) factors relating to implementation schedules and "lumpiness" of various resource options, such as construction or installation times or delays in those times, risk of project failure or cost increase, (5) environmental and regulatory risks, such changes in emission standards (including the likelihood of CO_2 regulations), new emission standards or fees, permitting risk, and (6) planning risk, for example, the risk that a resource will become obsolete or unnecessary while under construction.

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[34] Direct Testimony of John N. Voyles, Jr., Commonwealth of Kentucky , Before the Public Service Commission, In the Matter of: *The Application of Louisville Gas & Electric Company for Certificates of Public Convenience and Necessity and Approval of its 2011 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2011-00162, June 1, 2011.

PUBLIC

Sensitivity scenarios can be used to test the robustness of a utility's analysis, and determine how sensitive it is to changes in input assumptions. In modeling impacts of EPA regulations, MISO modeled over 400 different sensitivity scenarios, varying emissions control technology costs, gas prices, and CO_2 prices. Georgia Power also modeled a range of gas and CO_2 prices, and also included scenarios where the timing of regulations was delayed by a year. Sensitivity scenarios should include fuel prices, O&M and capital costs for both emissions control technologies and new natural gas technologies.

Utilities must choose a manner in which to evaluate the reasonableness and cost of their compliance strategies. PSCo compared the total portfolio costs and emissions output of the nine different scenarios that it chose to model. Georgia Power examined each of its generating units on an individual basis, comparing the ongoing operating costs with emissions controls to the cost of replacing the unit with site-specific natural gas generation. Kentucky Utilities and LG&E also looked unit by unit, but looked progressively, ordering the units from highest to lowest operating costs and removing retired units from the analysis before examining the others. Each of these methods has advantages and disadvantages, but each provides a way of examining coal-fired units in a systematic way to determine whether they should be retrofit or retired.

v. Transparent modeling process

All of the entities in other states and regions used or are using a capacity expansion or generation dispatch model (or both) to perform their analyses. If models are to be used to evaluate compliance strategies, those models should be appropriate to the task, and the process should be transparent to Commissioners, commission staff, and all intervenors. Attempting to understand non-transparent modeling can take time, and extend or burden the PUC process. In Colorado, PSCo was criticized for its modeling process. Intervenors who were capable of using the same model in their advocacy observed that they did not have sufficient time to come up with alternate compliance plans, and when PSCo submitted modeling data to the PUC, intervenors stated that there were insufficient data to fully participate in the process. If a utility is using one or more models, it should provide a list of the models it is using and describe what it is using them for. Model inputs should be provided generally and in machine readable form for those intervenors that can run the model themselves. Model outputs should be provided generally and in machine readable form so other parties doing modeling can verify those results. Participants in the Minnesota process stated that they wanted the opportunity to review the IPM model being used by EPA, so that they can make sure they know what is actually in the model and that they can trust the assumptions. This is critical for any modeling analysis being performed.

Utility compliance plans will ultimately result in rate cases as the utilities seek cost recovery for their investments. The Iowa Utilities Board will determine whether investments are prudent, asking the following types of questions:

- Are the costs incurred to meet the needs of customers?
- Are the costs necessary to provide adequate service?
- Are the costs reasonable?
- Was the technology selection prudent?

- Is the plant investment used and useful?
- Will ratepayers derive a benefit?[35]

Compliance plans that have included all the items mentioned above can provide hypothetical answers to these questions much more easily, moving the Board process along in an efficient manner.

5. Conclusion

In examining investor-owned utility emissions compliance plans, the Board should look for (1) a thorough inventory and description of the relevant risks, together with an assessment of their probabilities, (2) an objective analysis of how those risks impact the performance of various resource plans individually and in combination, (3) development of a plan relying on a portfolio of resources that manages risk and uncertainty to a reasonable level while delivering the lowest life-cycle cost over the fullest possible range of plausible future scenarios. In order to facilitate review by the Board and parties, and to promote accuracy, these assessment and data gathering activities should be transparent (clear and understandable to the Board, the parties and the public), fully documented and supported by work papers and methodologies that allow the Board and the parties to determine their validity, quantitative whenever possible, and treat all resources on a level playing field.

The Board is urged to think beyond a simple selection among alternative power plant retrofits to determine the optimal configuration for meeting regulatory requirements over the long term. When compared with the high cost of traditional retrofits, options such as new wind generation, demand-side management, energy efficiency, fuel switching at the existing units, and underutilized and/or new combined cycle natural gas capacity, in combination with coal-unit retirements, may present the "optimal" cost and risk configuration for complying with new environmental and public health-based requirements.

[35] Lowell E. Alt, Jr., *Energy Utility Rate Setting*. 2006.