BEFORE THE CORPERATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR COMMISSION AUTHORIZATION OF A PLAN TO COMPLY WITH THE FEDERAL CLEAN AIR ACT AND COST RECOVERY; AND FOR APPROVAL OF THE MUSTANG MODERNIZATION AND COST RECOVERY	**))))))))**	**CAUSE NO. PUD 201400229**

Direct Testimony of
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PUBLIC VERSION

On Behalf of
Sierra Club

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address, and position.

A My name is Jeremy Fisher. I am a Principal Associate with Synapse Energy Economics, Inc. ("Synapse"), which is located at 485 Massachusetts Avenue, Suite 2, in Cambridge, Massachusetts.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q Please summarize your work experience and educational background.

A I have ten years of applied experience as a geological scientist, and six years of working within the energy planning sector, including work on integrated resource plans, long-term planning for utilities, states, and municipalities, electrical system dispatch, emissions modeling, the economics of regulatory compliance, and evaluating social and environmental externalities.

I have provided consulting services for various clients, including the U.S. Environmental Protection Agency ("EPA"), the National Association of Regulatory Utility Commissioners ("NARUC"), the California Energy Commission ("CEC"), the California Division of Ratepayer Advocates ("CADRA"), the National Association of State Utility Consumer Advocates ("NASUCA"), National Rural Electric Cooperative Association ("NRECA"), the State of Utah Energy Office, the state of Alaska, the state of Arkansas, the Regulatory Assistance Project ("RAP"), the Western Grid Group, the Union of Concerned Scientists ("UCS"), Sierra Club, Earthjustice, Natural Resources Defense Council ("NRDC"), Environmental Defense Fund ("EDF"), Stockholm Environment Institute ("SEI"), Civil Society Institute, New Energy Economy, and

Clean Wisconsin. I developed a regulatory tool for EPA and state air quality agencies, released by EPA in 2014 as the Avoided Emissions and Generation Tool ("AVERT"), and continue to provide technical support to EPA regarding electric utility planning practices.

I have provided testimony in electricity planning and general rate case dockets in Indiana, Louisiana, Kansas, Kentucky, Oregon, Nevada, New Mexico, Utah, Wisconsin, and Wyoming. I have reviewed and evaluated the energy planning practice of utilities in dockets involving integrated resource plans ("IRP") and retrofit preapproval dockets, commonly referred to as certificates of public convenience and necessity ("CPCN").

I hold a B.S. in Geology and a B.S. in Geography from the University of Maryland, and a Sc.M. and Ph.D. in Geological Sciences from Brown University.

My full curriculum vitae is attached as Exhibit JIF-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified in front of the Oklahoma Corporation Commission previously?

A No, I have not.

Q What is the purpose of your testimony?

A My testimony reviews the economic modeling performed by Oklahoma Gas & Electric (OG&E, or "the Company") and compares it against best practice resource planning. I examine the assumptions made by the Company with regard to carbon dioxide ("CO_2") regulations, and compare this against potential outcomes and actions taken by other companies. Finally, I review analyses conducted by my colleagues, Mr. Tyler Comings and Ms. Rachel Wilson, and provide recommendations to this Commission.

2. COMPARISON OF OG&E ENVIRONMENTAL COMPLIANCE PLAN AGAINST OTHER RETROFIT PREAPPROVAL PROCEEDINGS

Q Please describe the process used by OG&E to determine the relative cost of retrofitting or converting Muskogee and Sooner units.

A OG&E developed a series of expansion plans that it would implement regardless of its decision about whether to retrofit, convert, or retire the Muskogee and Sooner plants. The Company included these fixed expansion plans in all of the modeling runs it conducted to evaluate the conversion, retrofit, or retirement of the coal units. The 2014 IRP[1] describes the process of developing these expansion plans very generally: "CCs [combined cycle natural gas plants] and CTs [combustion turbine natural gas plants] were then distributed across the 30-year forecast period with in-service dates as necessary to meet OG&E's projected capacity needs."[2] With these expansion plans in place, OG&E assumed that it would need to replace any coal retirements with one-to-one natural gas combined cycle ("NGCCs") units,[3] regardless of an actual energy or capacity need. The total cost of these plans was then determined using a production cost model (PCI Gentrader).

Q Did the Company perform any optimizations of their fleet composition in the presence or absence of Muskogee and/or Sooner plants?

A No. At no point does it appear that OG&E used any form of capacity expansion model to determine the optimal fleet composition to meet its customers' anticipated demand for electricity.

Q Is the lack of an optimization model best practice in these types of cases?

A Not in my opinion. When a significant change occurs in the fleet, two things occur: first, the operating characteristics of the rest of the fleet change;[4] and second, opportunities open to meet customer demands through a portfolio of options.

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[1] Attached to Mr. Howell's Testimony as LCH-1.
[2] See LCH-1, OG&E 2014 IRP Update, Page 41.
[3] OG&E actually replaces retiring coal with an additional 10% capacity in NGCC, technically 1.1:1.
[4] Primarily due to transmission constraints and unit commitment characteristics.

Capacity expansion or optimization models are meant to provide reasonable alternatives without second-guessing outcomes. These models review customer peak and energy demand, as well as current and projected resources, and build resources as required to meet those demands at the lowest possible cost – hence the optimization. Typically, these models are populated with a large number of supply-side (and sometimes demand-side) resources, and are allowed to choose the least cost mix of resources. While capacity expansion models are not able to get at the details of chronological dispatch, they are designed to determine a reasonable portfolio of generation options that meet customer demands at the least cost. Such portfolios may include a combination of fossil generation, renewable energy, and demand-side management programs in combinations that specifically minimize total customer costs. Even small changes in a portfolio, such as delaying unnecessary resources by several years, or preventing the acquisition of a high cost resource can make a significant difference.

In the case of OG&E, a capacity expansion model could have significantly changed the outcome of the Company's analysis – particularly in comparing futures with significant baseload coal against futures with more conversions or new gas-fired units. OG&E projects that its coal-burning fleet will run at fairly high capacity factors, reaching energy saturation in just a few years and limiting opportunities to accept additional low-cost, high-energy resources such as wind. In the alternate case, however, when a larger fraction of the Company's capacity is maintained in peaking units (such as gas CTs and gas-fired boilers), energy-rich resources like wind become attractive alternatives. It is quite possible that an expansion capacity model, given the opportunity to take low-cost wind, would have found wind and capacity resources to be a cost-effective mechanism of meeting customer loads – at lower cost than the pre-supposed expansion plan provided by OG&E.

In OG&E's case, it never used a capacity expansion or optimization model (neither PROMOD or PCI GenTrader have this capability). By establishing a fixed expansion plan that added natural gas combined cycle natural gas plants

("NGCC") and combustion turbine units on specific dates, OG&E never allowed PROMOD or PCI GenTrader to do what the models were designed to do. In essence, the Company substituted a mathematical optimization model with manual selection. In doing so, the Company likely failed to find least-cost solutions for ratepayers, confounding the economic analysis results. I believe that there are likely more optimal (i.e. lesser cost) plans that were not captured because of the failure to use an optimization framework. Therefore, the Company's valuation of Sooner 1 & 2 is likely overly optimistic, even setting aside other analysis defects discussed by my colleagues Mr. Comings and Ms. Wilson.

3. IMPACT OF CARBON DIOXIDE REGULATIONS ON OG&E DECISIONS

Q How does OG&E consider regulations to curb carbon dioxide emissions from power plants in this docket?

A The Company reviews regulations to curb carbon dioxide ("CO_2") emissions as just one of several sensitivities, and fully excludes it both from the base case and the primary scenarios reviewed.[5] In fact, out of 60 cases analyzed by OG&E in its environmental compliance plan ("ECP"), only five (or about 8%) even considered an impact from carbon regulations on OG&E's fleet.[6] In marginalizing this regulation, the Company has significantly downplayed the risk posed by carbon regulation in the near and far term.

Q In the discrete cases where OG&E did consider an impact from carbon regulations, how were those regulations incorporated into the analysis?

A In the five cases (of 60) where carbon restrictions *were* considered, the Company projected a carbon price, which could represent either a market price for tradable carbon allowances, a tax on carbon emissions, or an implied price from other activities that compel reductions from sources that emit CO_2. This price was

[5] See LCH-1, OG&E 2014 IRP Update, Page 44 , Figure 14 (indicating 15 cases, none of which include CO_2).
[6] See LCH-1, OG&E 2014 IRP Update, Pages 42-46 , Figure 10 (indicating 15 portfolios), Figure 14 (indicating 15 cases), and Figure 17 (indicating 30 cases). CO_2 is featured only in Figure 17 in one of six sensitivities.

assumed to start in 2020 at a cost of $15/ton. In real terms, the CO2 price rises by an average cumulative average growth rate of [redacted]% to 2044.[7] The Company calculated these prices as the cost of emissions required to make the variable production cost of coal equal to the production cost of gas (i.e. the coal-gas spread). In doing so, the Company assumed that a carbon price that forced parity between coal and gas production costs would sufficiently represent a policy requiring emissions reductions.

Q What is the outcome of the analysis where the Company reviewed the impact of a carbon price on its portfolio?

A When the Company's analysis included a carbon price, the choice to convert all four units in question, Muskogee 4 & 5 and Sooner 1 & 2, was superior to the other four Compliance Alternatives considered, beating the Company's preferred scenario of Scrub/Convert by about $500 million. This would suggest that, with the assumption of the Company's price for carbon dioxide, maintaining Sooner 1 & 2 as coal-fired presents a liability of $500 million to ratepayers.

Q Is it reasonable to exclude carbon regulations from consideration in the base case?

A No. On June 25, 2013, the President announced that he was directing the U.S. Environmental Protection Agency ("EPA") to formulate, propose, and finalize a rule regulating carbon emissions from new and existing fossil fuel fired electricity generators.

On June 2, 2014, EPA proposed its Clean Power Plan ("CPP") under Section 111(d) of the Clean Air Act.[8] The CPP aims to regulate emissions of CO_2 from existing fossil fuel-fired power plants—such as Muskogee and Sooner—by setting binding, state-specific carbon emission reduction goals for all affected electric generating units ("EGU"). These emissions reduction goals reflect the degree of emissions reductions achievable through the application of the "best

[7] Calculated from Company gas and coal price projections using method employed by OG&E.
[8] EPA 2014. See resources online at http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule

system of emission reduction." Oklahoma, for example, will be required to reduce its average CO_2 emission rate for affected EGUs from the 2012 baseline rate of 1,387 lbs/MWh[9], to 895 lbs/MWh[10] by 2030—an effective 35.5% reduction statewide. The CPP's reach is broad and seeks to explicitly impact electric power planning, dispatch, and procurement, with provisions that encourage coal/gas switching, renewable energy procurement, and energy efficiency programs. The comment period on the main proposal closed on December 1, 2014, and EPA is required to finalize a rule by June 2015.

The proposed rule provides for flexibility in state compliance, including allowing options for states to meet fleet-wide emission rate-based limits or state mass-based emissions targets through heat rate improvements, increased dispatch of natural gas generating resources, energy efficiency, renewable energy programs, and/or cap-and-trade programs. States can act independently, or enter into regional agreements with other states to achieve compliance.

Q Is the implementation of the CPP the only reason to include a real or notional price on carbon emissions?

A No. Outside of the rulemaking process, as a scientist who studied the impacts of climate change on ecosystems, peoples, and infrastructure, it is my opinion that there is sufficient, indeed overwhelming, evidence that climate change is both real and, in large part, attributable to anthropogenic emissions. As evidence mounts regarding the impacts climate change is already having on our everyday activities, economy, and national security, we as a nation will have to develop both mitigation and adaptation policies.

I recognize that the process of moving the electric sector to lower carbon emissions via a political process has been politically fraught, and is likely to remain so for the foreseeable future. Nonetheless, the assumption that the United

[9] See CPP Goal Computation Technical Support Document. Appendix 5. Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-goal-computation.pdf
[10] See CPP Goal Computation Technical Support Document. Appendix 3.

States will continue to allow CO_2 emissions from the electric sector to continue unabated for the next three decades is unreasonable.

Q The Oklahoma Attorney General and eleven other states have issued a lawsuit against EPA with regards to the proposed CPP. Why should Oklahoma utilities assume that the rule will move forward?

A The Oklahoma AG's ("OAG") effort to halt or alter the Section 111(d) rulemaking process[11] should not be the primary consideration for OG&E's ratepayers. Legal challenges are typically filed in response to major EPA regulatory actions, but this does not excuse OG&E from its responsibility to comply with those regulations at the least cost, at a reasonable level of risk, for Oklahoma ratepayers. Forecasts are not appropriate venues for political outlooks. For example, OG&E might hope that coal prices will fall substantially, or might desire significant new load in their service territory – but it would be inappropriate to bank on these outcomes on behalf of OG&E ratepayers. Simply hoping that the OAG prevails against EPA does not serve OG&E's ratepayers, and confounds political desires with prudent analyses.

Q Does the history behind the Oklahoma Regional Haze Rule, support your conclusion that OG&E should consider costs associated with the 111(d) rule even though the OAG is challenging the rule?

A Yes. On December 11, 2011, EPA rejected portions of the Oklahoma State Implementation Plan ("SIP") and issued a Federal Implementation Plan ("FIP") related to Regional Haze sulfur dioxide (SO_2) emission requirements.[12] Rather than analyzing how this rule would impact its fleet, OG&E ignored the potential impacts of this rule in its 2012 IRP with the hope that a legal challenge to the rule would prevail.[13] In May 2014, the Supreme Court declined to hear OG&E's

[11] Petition for Review in US Court of Appeals for the District of Columbia Circuit. July 31, 2014
[12] 76 Fed. Reg. 81,727 (Dec. 11, 2011).
[13] See OG&E 2012 IRP, page 48-49. "OG&E filed a stay request on the SO2 emission requirements of the Regional Haze rule in the U.S. Court of Appeals for the Tenth Circuit on April 4, 2012, which was granted on June 22, 2012. The stay will remain in place until a decision on the petition for review is complete, which will delay the implementation of the SO_2 emission requirements of the 2012 Integrated Resource Plan Regional Haze rule. Given the grant of the stay and the pending petition for review, OG&E believes that it is premature to move forward with installation of scrubbers."

challenge, suddenly leaving the Company with an IRP $1 billion short of legally required retrofits.[14] OG&E appears to once again be banking on a legal challenge to a federal rulemaking, and in doing so unreasonably claiming that there will be no carbon costs for the next thirty years. When OG&E refuses to acknowledge reasonable regulatory risks, it inappropriately exposes its ratepayers to high cost consequences – costs that OG&E could otherwise mitigate.

Q How are other utilities responding to the proposed Section 111(d) rule?

A Although I have not taken an extensive survey of utility responses, the largest utilities are taking the proposal seriously, and examining their resource options for compliance, as described below. As I noted previously, the proposed rule provides both significant flexibility in meeting (and even interpreting) targets, and significant ambiguity in interpreting provisions. Therefore, some utilities are actively working with stakeholders to interpret the proposal and review compliance options, while other utilities have settled into using a proxy CO_2 price for forward planning as they await clarity from EPA and state regulators.

For example, while constructing this testimony, I attended a technical workshop hosted by PacifiCorp (a utility with generation and load in nine western states) specifically focused on modeling Section 111(d) compliance across multiple states.[15] The utility has traditionally used a carbon price assumption in all of its reference or base cases supporting IRP and CPCN dockets, and is now generally substituting that price with a rate-based compliance mechanism. Notably, a large fraction of PacifiCorp's generation is served from Wyoming, a co-signatory to the lawsuit against EPA's proposed 111(d) rule. Nonetheless, PacifiCorp has made its intent clear to model 111(d) requirements in thirteen of fourteen cases (93%),[16]

[14] See OG&E Press Release, May 27, 2014. "U.S. Supreme Court declines to hear OG&E's Regional Haze case: Company expresses disappointment with decision," Attached as Exhibit JIF-2.

[15] PacifiCorp 2015 IRP Public Input Meeting 5. November 14, 2014. Page 35. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP_PIM05_11-14-2014_FINAL.pdf Attached as Exhibit JIF-3.

[16] PacifiCorp 2015 IRP Public Input Meeting 5. November 14, 2014. Page 24.

and has treated the CPP as one of the two primary environmental compliance risks under review.

In an ongoing docket in Indiana, Indiana Michigan Power Company, a subsidiary of American Electric Power, which also owns Oklahoma Public Service Company (PSO), uses a carbon price in the reference case of evaluating the economics of continuing to operate Rockport unit 1, a large coal generating station in southern Indiana.[17] Like Wyoming, Indiana is also a party to the lawsuit against EPA's proposed 111(d) rule. Nonetheless, Indiana Michigan Power Company uses a carbon price in four of five (80%) of its core cases.[18]

Similarly, although Kentucky is also a party in the EPA lawsuit, the largest utilities in this state are very actively considering mechanisms of meeting more stringent carbon reduction requirements. Kentucky Utilities and Louisville Gas & Electric (KU/LG&E) are engaged in ongoing review of an IRP filed in early 2014. In the most recent addendum to this docket, filed October 17, 2014, the utilities reviewed twenty-one cases, of which twelve (57%) assumed either a carbon price or a cap on greenhouse gas emissions from the utility.[19]

Q Is it your opinion that OG&E should have used a carbon price in the base case?

A Yes. The Company's reasonable baseline assumption should be proposed regulations pose enough of a risk that they warrant serious assessment and mitigation. If the assessment of the Company's fleet looked identical with and without the assumed regulatory impact, there might be a case to be made that the plan is robust regardless of the final disposition of the rule. However, the proxy

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[17] Direct Testimony of Mr. Scott Weaver (AEP) in Indiana Cause 44523. Page 48, lines 10-16. "the proposed rule is centered on the achievement of future state-specific CO_2 emission reduction targets that were predicated on a set of suggested "building block" metrics. Because of that complexity and uncertainty, it is the Company's position that it would be necessary to attempt to reasonably 'proxy' the potential relative economic implication on Rockport Unit 1 by way of assessing the deleterious impact of such "CO_2 pricing." Attached as Exhibit JIF-4.

[18] Direct Testimony of Mr. Scott Weaver (AEP) in Indiana Cause 44523. Table 3, pages 37-38.

[19] Kentucky Docket 2014-00131. October 2014. KU/LG&E 2014 IRP. 2014 Resource Assessment Addendum. http://psc.ky.gov/pscecf/2014-00131/rick.lovekamp@lge-ku.com/10172014103810/2014_Resource_Assessment_Addendum_2014-IRP_10-17-14.pdf

price for CO_2 considered by OG&E has a dramatic operational impact on Sooner – and thus should be considered a significant risk.

Q Do you have a good sense of exactly what the CPP will require when implemented in Oklahoma?

A No. The CPP bestows a tremendous amount of flexibility on states to engage in direct regulation of sources, influence and enforce utility planning activities, or engage in market-based emissions trading. States are currently figuring out mechanisms by which they can comply, and searching for cost-effective means of meeting EPA's anticipated final regulations. However, because coal plants have carbon dioxide emission rates that far exceed the state's 2030 target rate, it is very likely that any plan developed by Oklahoma will limit the operations of existing coal units in a material way.

Q How should the Company evaluate compliance costs of the CPP in this docket given the flexibility in the proposed rule?

A In the absence of a firm state plan or further EPA guidance, the Company has two options: 1) create a proxy plan for Oklahoma that it believes would meet EPA requirements, with its own contribution explicitly stated; or 2) use a proxy price (or prices) to represent a possible slate of activities that impact power sector CO_2 emissions. Generally, I think that for transparent planning purposes, utilities should continue using proxy "trading" prices until more information is known either on a federal or state level.

Q In previous years, has OG&E explored the impact of CO_2 prices on its resource decisions?

A Yes. In every IRP filed since 2009, OG&E has explored scenarios with CO_2 price impacts. In the 2009 IRP, four of five scenarios (or 80%) included some form of restriction on CO_2 emissions, including the expected or reference case.[20]

[20] *See* OG&E 2009 IRP, Table 31 "Assumed CO2 Price in Nominal Dollars." Also page 44: [redacted]

In the 2011 IRP, OG&E evaluated the impact of carbon pricing in half of their scenarios (50%), stating that "many other [utilities] still evaluate CO_2 legislation and… it would be negligent not to analyze that impact."[21] In the published 2011 IRP, the Company recognized that EPA's intent to impose restrictions on carbon dioxide could impact its system, stating:

> In the absence of federal legislation, the EPA has taken action to begin regulating CO_2 and other greenhouse gases using its existing authority under the Clean Air Act. Specifically, EPA agreed in December 2010 to issue Emission Guidelines under Section 111(d) of the Clean Air Act that could give rise to greenhouse gas emission limits for existing electrical generating units.[22]

OG&E's judgment that it was necessary to seriously account for carbon dioxide regulatory risk was consistent with the practice many other utilities around the country.[23] However, by the 2012 IRP, OG&E had withdrawn all discussion of the potential for carbon regulation under 111(d), instead including a carbon price in only one of nine sensitivities (11%). The 2012 IRP failed to include any discussion of carbon price or regulatory risk, only stating that "the 2012 Annual Energy Outlook [AEO] assumes no explicit federal regulations to limit greenhouse gas emissions, therefore CO_2 emission costs were only included as a sensitivity."[24] This explanation is broadly without merit, however, as EIA's forecasts generally only include promulgated rules and policies.[25] EIA's requirement to provide fuel forecasts based on final regulations does not comport

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[redacted] Also, Table 34 "Summary of Ventyx Scenario Drivers and Key Assumptions."

[21] See OG&E 2011 IRP, Meeting Documentation from OGE 2011 IRP Oklahoma Collaborative Technical Conference, February 2011 , page 16.

[22] *See* OG&E 2011 IRP, page 25.

[23] See Synapse CO_2 Price Report, Spring 2014. May 22, 2014. Figure 3. Available at http://www.synapse-energy.com/sites/default/files/SynapseReport.2014-05.0.CO2-Price-Report-Spring-2014.14-039.pdf. Attached as Exhibit JIF-5.

[24] OG&E 2012 IRP, page 28.

[25] See Assumptions to AEO 2014. Page 3. "The version of NEMS used for AEO2014 generally represents current legislation and environmental regulations, including recent government actions for which implementing regulations were available as of October 31, 2013, as discussed in the Legislation and Regulations section of the AEO." http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2014).pdf

with OG&E's responsibility to produce reasonable forecasts that actually capture risks to the Company's ratepayers.

In the 2014 IRP, the planning document supporting this case, OG&E again dismisses the risk of CO_2 regulation by considering it only as a sensitivity, this time only reviewing the impacts in about 8% of the runs executed. The 2014 IRP again fails to mention the impending carbon restrictions under Section 111(d), resorting to the same explanation that because "the 2014 Annual Energy Outlook Early Release assumes that there are no explicit federal regulations to limit greenhouse gas emissions . . . CO_2 emission costs were only included in the analysis as a sensitivity."

The clear implication of the 2012 and 2014 IRPs, and the resulting ECP, is that OG&E is willing to dismiss a risk considered imminently transformative by other utilities, and indeed by the state of Oklahoma. In comments preceding the release of the CPP the Oklahoma Attorney General indicates that a "'mass-emissions approach' . . . will result in wholesale turnover of the generation fleet at ratepayer expense through the mandated CO_2 reductions."[26] It would seem that a risk of such priority to the state of Oklahoma would at least register as a significant risk for OG&E to consider on behalf of its ratepayers as well.

Q What are your recommendations with regards to modeling carbon regulations in this docket?

A OG&E should review the impact of carbon pricing or other proxy plans to meet the proposed CPP in its <u>reference case</u> rather than just as a sensitivity. By relegating the scenario that examines CO_2 pricing to a one-off sensitivity, rather than considering this scenario as part of the base case, the Company significantly discounts and distorts the potential of this regulation <u>and</u> fails to examine the impact of additional risks in conjunction with the CO_2 price. These limitations substantially impair the Company's analysis.

[26] Oklahoma AG. April 2014. The Oklahoma Attorney General's Plan: The Clean Air Act Section 111(d) Framework that Preserves States' Rights. Page 5, Attached as Exhibit JIF-6.

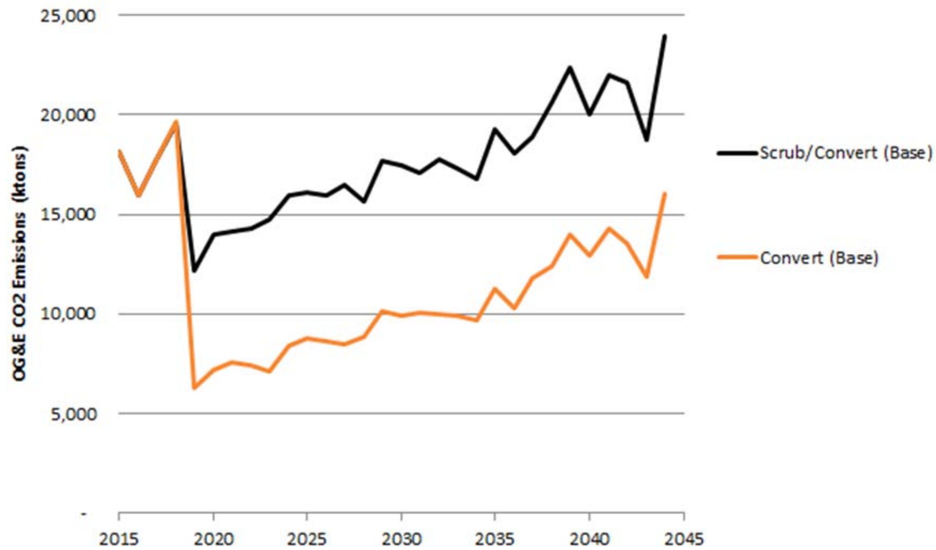
The Company should look both at the impacts of its own CO_2 price assumption, and at the possibility of a more rigorous CO_2 price forecasts developed by third parties. The Company should consider one of these two possibilities in its base case, rather than using the current Company assumption of zero cost and no regulation.

Q How do CO_2 emissions projected by the Company compare against the CPP requirements?

A At this point, it is unclear exactly how to compare the Company's fleet emissions against the rate projections from EPA. In part, this is because EPA has provided the opportunity for states to meet emissions requirements through incremental additions of renewable energy and energy efficiency, which are fairly low cost resources. However, OG&E is not pursuing aggressive energy efficiency ("EE") or large new renewable energy ("RE") programs, and because the Company has failed to address the CPP, OG&E has certainly not demonstrated that EE or RE could or will serve as its compliance mechanism.

Overall, we can compare the effect of OG&E's CO_2 price on the Company's fleet against EPA's estimate of CO_2 reductions required from each state. Reviewing two critical scenarios provided by the Company—the preferred Scrub/Convert scenario and the Convert [all] scenario with no carbon price— we see that both scenarios achieve a fairly substantial drop in emissions from 2015 to 2020, primarily due to the conversion of Muskogee 4 & 5 (see Figure 1, below). The case in which both the Muskogee and Sooner plants are converted results in a far steeper set of reductions.

Figure 1. OG&E system CO_2 emissions[27]



On November 13, 2014, EPA released a Notice of Additional Information ("NODA") regarding the CPP,[28] and an accompanying Technical Support Document ("TSD"), which provided an illustrative example of how states might estimate a mass-based emissions target equivalent to EPA's proposed rate-based goals.[29] Setting aside questions about the construction of the CPP goals or the TSD's mechanism, and assuming that OG&E bears a *pro-rata* responsibility to reduce its emissions relative to the state target, the TSD implies a 24% reduction in new and existing source CO_2 emissions from 2012 levels by 2020, and a 27% reduction by 2023.[30,31]

[27] Source: Response to OIEC DR 1-11. Files OIEC 1-11_Att03_2014_IRP_ProdCost_Convert_Base_CT_spread.xlsx and OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.

[28] 79 Fed. Reg. 67406. Notice; additional information regarding the translation of emission rate-based CO2 goals to mass-based equivalents.

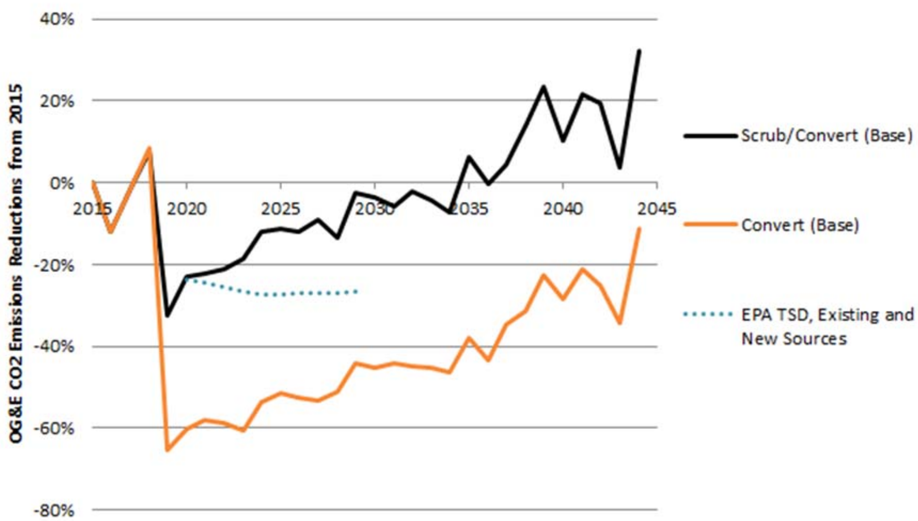
[29] EPA, November 2014. Technical Support Document: Translation of the Clean Power Plan Emission Rate-based CO2 Goals to Mass-based Equivalents. http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-translation-state-specific-rate-based-co2

[30] See file "rate_to_mass_translation.xlsx" attached to CPP NODA TSD, row 43 (Oklahoma), columns BF (2012 tons) and CR-DA (2020-2030 Mass-Based Equivalent - Existing Affected and New Sources).

[31] Please note that the mass emissions target is based on EPA's illustrative example. In the EPA example cited here, the agency projects load growth through 2030, and effectively assumes that new growth is met with new natural gas units as required. EPA then provides two mass-based targets – one where the target is based on only existing sources, and the other based on the combination of existing and new assumed gas units. The example cited here includes both existing and new units, an example which is consistent with

Comparing these reduction levels against the reductions (from 2015) achieved by the Scrub/Convert and Convert cases in the absence of a CO_2 price, we see that while the Scrub/Convert case initially meets the illustrative EPA mass-based targets for new and existing sources (combined), it then quickly exceeds those targets in every year after 2020. By 2030, the Scrub/Convert case is effectively back to 2015 emissions levels (see Figure 2) and well above EPA targets.

Figure 2. OG&E system CO_2 emissions reductions from 2015, EPA rate-to-mass TSD reductions from 2012.



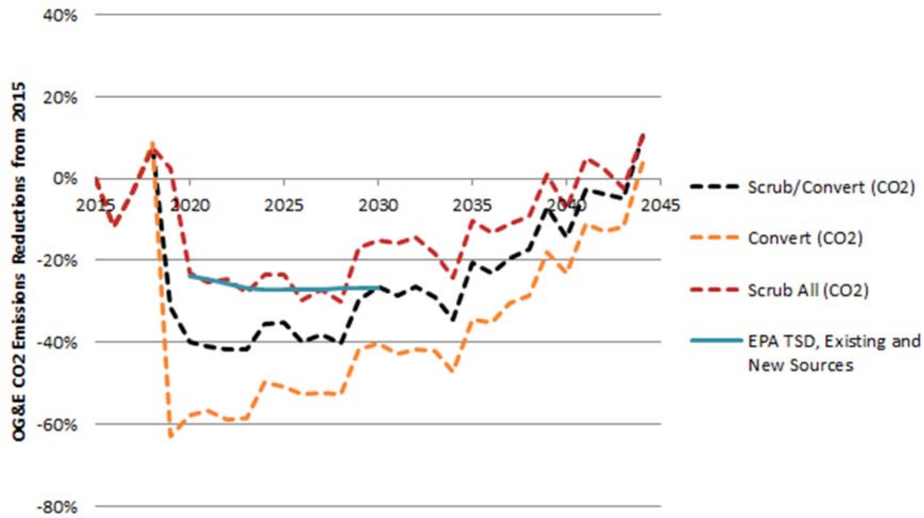
In the base case, the Convert scenario is well below the EPA targets, requiring no further reductions, and remaining below targets for the entirety of EPA's current proposed rule compliance period, which ends in 2030, and for several years beyond that.

With the incremental addition of the Company's carbon price projection, the Scrub/Convert case does meet EPA targets through roughly by the end of the compliance period. In fact, even the case in which all of the units are scrubbed

OG&E's total reported emissions from existing and new units. Because it includes both existing and new units, the mass-based does not drop as steeply as the rate-based goal.

meets EPA's illustrative targets through 2028 in the presence of OG&E's CO_2 price (see Figure 3, below).[32]

Figure 3. OG&E system CO_2 emissions reductions from 2015, EPA rate-to-mass TSD reductions from 2012.



We can therefore say that, roughly speaking, the Company's carbon price achieves EPA's goals in the Scrub/Convert case, and nearly meets the goals through 2028 when all four units are scrubbed. No CO_2 price is required, however, when Muskogee 3 & 4 and Sooner 1 & 2 are all converted – the fleet meets EPA targets without any additional cost for CO_2 (see the "Convert" case in Figure 2, above).

Q What does it mean that when all four units are converted, a CO_2 price isn't required to meet EPA targets?

A There are two ways to think about the purpose of a CO_2 price. In one instance, the price is a mechanism to facilitate trade between entities under a cap, where a limited number of allowances are made available for trading. In another instance, a simple penalty is incurred (i.e., a tax) for emitting CO_2. In the case of the CPP, because compliance is required at the state level and each state has a different target, states could employ a variety of mechanisms to reach compliance. For

[32] With a CO_2 price intact, OG&Es' units dispatch significantly less, and thus produce fewer emissions, ultimately meeting EPA's illustrative mass-based targets in most years.

example, Oklahoma might assign a *pro-rata* emissions reduction requirement for each utility, to be met via fuel switching, retirements, or other trading. In OG&E's case, when all four units under consideration are converted, the Company meets (and exceeds) its *pro-rata* obligation, and would therefore not incur any penalties for emitting CO_2. In fact, in a tradable scheme, OG&E would be eligible to receive credits because it surpasses the target.

However, when none of the units are converted, a CO_2 price comparable to, or in excess of, the Company's estimate is required for OG&E to meet their *pro-rata* target—at least through 2028. After 2028, a more substantial cost would have to be incurred to prevent emissions from spiking past mandated targets.

In the Scrub/Convert case, the Company's CO_2 price may be sufficient to meet requirements through all of the years—although a prudent review might suggest that a higher price is required past 2030 to prevent a rebound in emissions.

If we take as indicative the idea that under the Convert (all) case the Company is released from any further emissions reductions obligations, but that the Company requires a carbon penalty to meet obligations under the Scrub/Convert case, then rather than comparing all of the cases with a CO_2 price, we should actually (roughly) compare the cost of the Convert scenario with no CO_2 price ($22.5 billion)[33] against the cost of the Scrub/Convert case with a CO_2 price ($26.4 billion),[34] and realize that the Convert (all) scenario provides carbon reduction benefits with significant monetary value.[35] The Convert case both saves OG&E from having to realize any further carbon reductions under the CPP <u>and</u> potentially lines up the Company for selling excess credits realized by its deeper reduction (if a trading system is enacted).

[33] OG&E 2014 IRP, Table 19, Base Case.
[34] OG&E 2014 IRP, Table 20, CO_2 case
[35] For an accurate comparison, a price should be found such that OG&E's fleet under Scrub/Convert meets EPA's targets exactly. This price should be applied to the Scrub/Convert scenario. Similarly, the value of exceeding the EPA targets in the Convert (all) case should be monetized and applied as a net benefit to the Convert case.

Q What should the Company use as a reference carbon price?

A The Company's proposed CO_2 price (only used in one sensitivity) appears to be sufficient for reaching compliance (or near compliance) under all of the Company's scenarios, and is therefore a reasonable reference case.

Q Should the Company also review other carbon price estimates?

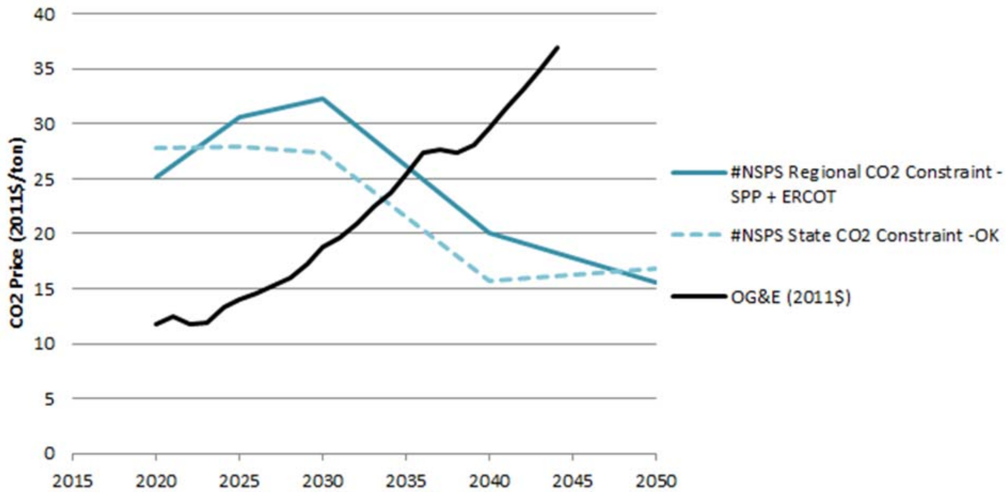
A Yes. While initial modeling suggests that a fairly low carbon price that is in line with the Company's estimates might be able to meet notional EPA mass-based targets, there remains uncertainty about the final form of the rule, its application, and its stringency. In addition to reviewing the outcome of its fleet with a zero carbon price assumption—a case that should be treated as a sensitivity rather than as a reference assumption—the Company should also review a higher carbon price estimate.

One option that the Company should review is the price of carbon assumed (or more correctly, derived) by EPA in modeling the implications of the CPP. When releasing the CPP proposal, EPA issued a Regulatory Impact Assessment ("RIA")[36] accompanied by economic modeling using the IPM model.[37] EPA performed two separate assessments, one assuming that states reach compliance individually, and another assuming that allowance trading occurs inside Regional Transmission Operator ("RTO") bounds. The IPM model uses various constraints to simulate CPP provisions, but does not explicitly model a carbon price. Instead, the model produces a shadow price of CO_2—i.e., a change in cost imposed by increasing a constraint, in this case, on carbon. The shadow prices from the state and regional (Southwest Power Pool) model runs are presented in Figure 4, below.

[36] EPA. June 2, 2014. Regulatory Impact Analysis: Clean Power Plan Proposed Rule. http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-regulatory-impact-analysis

[37] EPA. June 2, 2014. EPA Analysis of the Proposed Clean Power Plan. http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html

Figure 4. CO_2 price in OG&E sensitivity, and shadow CO_2 prices from EPA IPM runs.[38]



The falling CO_2 shadow price in EPA's IPM runs are a function of (a) an assumption of increased natural gas dispatch in early compliance years, and (b) the accumulating impact of greater energy efficiency and renewable energy in later years.

Q How should OG&E consider EPA's IPM shadow price for CO_2 emissions?

A I believe that EPA's shadow price for CO_2 emissions makes for a reasonable upper bound, or high case, in Oklahoma. The case represents a world in which Oklahoma generators are not retired *a priori*. Since we do not know what the final CPP or carbon rule will look like, it is reasonable to also test the outcome of the Company's model under a more stringent CO_2 price.

4. <u>CONCLUSIONS AND RECOMMENDATIONS</u>

Q Please provide your conclusions and recommendations in this case.

It is my opinion that, in addition to the deficiencies identified and described by my colleagues Mr. Comings and Ms. Wilson, the Company's model structure and assumptions regarding the risk of carbon regulations significantly bias its findings and are imprudently considered. OG&E's failure to use an optimization model to

[38] OG&E CO_2 price derived from OIEC 1-25_Att1 using OG&E methodology. Values match for all OG&E reported years in 2014 IRP.

seek a least cost portfolio in the absence or conversion of its coal units confounds its economic assessment, and likely overestimates the value of Sooner 1 & 2.

The Company has failed to adequately examine and mitigate the risk of carbon regulations, inappropriately and unnecessarily exposing ratepayers to increased costs. The Company's modeling clearly indicates a failure of its coal units under even a modest carbon price, a red flag under any circumstance, and of particular urgency in light of the pending carbon rule from EPA.

As my colleague Mr. Comings shows, the Company's own analysis indicates that Sooner 1 & 2 are marginal, at best, under most of the scenarios and sensitivities examined by OG&E. When the additional risk of regulations for ozone, and hence oxides of nitrogen ("NOx"), are considered, Sooner 1 & 2 fail under all but the extreme gas case. I've shown that the Company's CO_2 price is a reasonable reference case. In this circumstance, even without the risk of impending NOx reduction requirements, Sooner 1 & 2 are non-economic. Once other considerations, such as increased wind and an optimal replacement portfolio, are considered, I believe that the value of Sooner 1 & 2 would be consistently negative. As shown by Mr. Comings and Ms. Wilson, the Company has significant opportunities to build a lower cost and cleaner portfolio that mitigates ratepayer exposure to impending environmental regulations. Retrofitting Sooner 1 & 2 are not part of that solution.

I recommend that this Commission deny the Company's application to retrofit Sooner 1 & 2, and require that the Company seek a least cost portfolio, which includes testing opportunities to acquire lower cost resources such as wind.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Cambridge MA. *Principal Associate*, 2013 – present, *Scientist*, 2007 – 2013.

Consulting on economic analysis of climate change and energy, carbon, and emissions policies. Quantitative evaluations of regional climate change impact, energy efficiency programs, long- and short-term electric industry planning, carbon reduction planning, and emissions compliance programs.

Tulane University, New Orleans, LA. *Ecology and Evolutionary Biology Postdoctoral Research Scientist*, 2006 –2007.

Determining Hurricane Katrina's impact on Gulf Coast ecosystems using satellite and field data.

University of New Hampshire, Durham, NH. *Earth, Oceans, and Space Postdoctoral Research Scientist*, 2006 –2007.

Organizing team synthesis review of causes and rates of natural rainforest loss in the Amazon basin.

Brown University Watson Institute for International Studies, Providence, RI. *Visiting Fellow*, 2007 – 2008.

Designing study to examine migratory bird response to climate variability in the Middle East.

Brown University Department of Geological Sciences, Providence, RI. *Research Assistant*, 2001 –2006.

Tracking impact of climate change on New England forests from satellites. Working with West African communities to determine impact of climate change and practice on landscape. Modeling coastal power plant effluent from satellite data.

EDUCATION

Brown University, Providence, RI
Doctor of Philosophy in Geological Sciences, 2006

Brown University, Providence, RI
Master of Science in Geological Sciences, 2003

University of Maryland, College Park, MD
Bachelor of Science in Geography and Geology, 2001

FELLOWSHIPS & AWARDS

- *Visiting Fellow*, Watson Institute for International Studies, Brown University, 2007
- *Finalist*, Congressional Fellowship, American Institute of Physics and Geological Society of America, 2007
- *Fellow*, National Science Foundation East Asia Summer Institute (EASI), 2003
- *Fellow*, Henry Luce Foundation at the Watson Institute for International Studies, Brown University, 2003

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Wyoming Public Service Commission (Docket No. 20000-446-ER-14): Direct testimony in the matter of the application of Rocky Mountain Power for authority to increase its retail electric utility service rates in Wyoming approximately $36.1 million per year or 5.3 percent. On behalf of Sierra Club. July 25, 2014.

Indiana Utility Regulatory Commissions (Cause No. 44446): Direct testimony evaluating the economic modeling performed on behalf of Vectren South in support of its application for certificate of public convenience and necessity for various retrofits at Brown 1 & 2, Culley 3 and Culley plant, and Warrick 4. On behalf of Sierra Club, Citizens Action Coalition, and Valley Watch. May 28, 2014.

Utah Public Service Commission (Docket No. 13-035-184): Direct testimony In the matter of the application of Rocky Mountain Power for authority to increase its retail electric utility service rates in Utah and for approval of its proposed electric service schedules and electric service regulations. On behalf of Sierra Club. May 1, 2014.

Louisiana Public Service Commission (Docket No. U-32507): Direct testimony regarding the application of Cleco Power LLC for: (i) authorization to install emissions control equipment at certain of its generating facilities in order to comply with the federal national emissions standards for hazardous air pollutants from coal and oil-fired electric utility steam generating units rule; and (ii) authorization to recover the costs associated with the emissions control equipment in LPSC jurisdictional rates. ON behalf of Sierra Club. November 8, 2013.

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Indiana Utility Regulatory Commission (Cause No. 44339): Direct testimony in the matter of Indianapolis Power & Light Company's application for a Certificate of Public Convenience and Necessity for the construction of a combined cycle gas turbine generation facility. On behalf of Citizens Action Coalition of Indiana. August 22, 2013.

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Resume dated December 2014

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PRESS RELEASE

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U.S. Supreme Court declines to hear OG&E's Regional Haze case

Company expresses disappointment with decision

OKLAHOMA CITY, May 27, 2014 /PRNewswire/ -- The U.S. Supreme Court today denied a petition filed by Oklahoma Gas and Electric and Oklahoma Attorney General Scott Pruitt asking the nation's highest court to review a 10th Circuit Court of Appeals decision on Regional Haze. The question that the Supreme Court declined to review is whether the Environmental Protection Agency (EPA) acted appropriately in rejecting Oklahoma's plan to address visibility at national parks and wildlife areas.

Last July, a split, three-member panel of the 10th Circuit ruled that the EPA lawfully exercised its authority to reject Oklahoma's state plan and instead impose a federally mandated plan on Oklahoma. OG&E and the Attorney General filed a joint appeal to the U.S. Supreme Court in January.

"We are disappointed on behalf of our customers," said OG&E spokesman Paul Renfrow. "We still believe that the Oklahoma State Implementation Plan would have enabled us to meet the Regional Haze requirements at a much lower cost. However, we accept the Court's ruling and now turn our attention to meeting the 55-month compliance deadline."

OG&E previously estimated that compliance with the EPA's plan would require an investment of more than $1 billion. Renfrow added that the company would soon announce how it would comply with the EPA's mandates.

In the past, the Governor's office, state Attorney General, Oklahoma Corporation Commissioners, Oklahoma Department of Environmental Quality and other state leaders voiced opposition to the EPA plan saying that the state developed a plan that would be equally effective and cost far less.

"We would like to express our appreciation to our state leaders and others for their efforts," Renfrow said. "We want to extend a special note of appreciation to Attorney General Pruitt for his tireless advocacy on behalf of Oklahoma's right to determine its own course to meet these new EPA requirements."

The Oklahoma plan had called for use of low-sulfur coal and gave affected utilities in the state the flexibility of achieving the visibility improvement goals of the Regional Haze rule in a more cost-effective way. The Regional Haze Rule pertains to visibility in national parks and wilderness areas and not to public health.

OG&E is a subsidiary of OGE Energy Corp. (NYSE: OGE), and serves more than 807,000 customers in a service territory spanning 30,000 square miles in Oklahoma and western Arkansas.

SOURCE OG&E

Media, Kathleen O'Shea, (405) 553-3395, or Financial, Todd Tidwell, (405) 553-3966

Print Page | RSS Feeds | E-mail Alerts | Financial Tear Sheet





2015 Integrated Resource Plan

Public Input Meeting 5

November 14, 2014

PACIFICORP
Rocky Mountain Power
Pacific Power
PacifiCorp Energy

Agenda

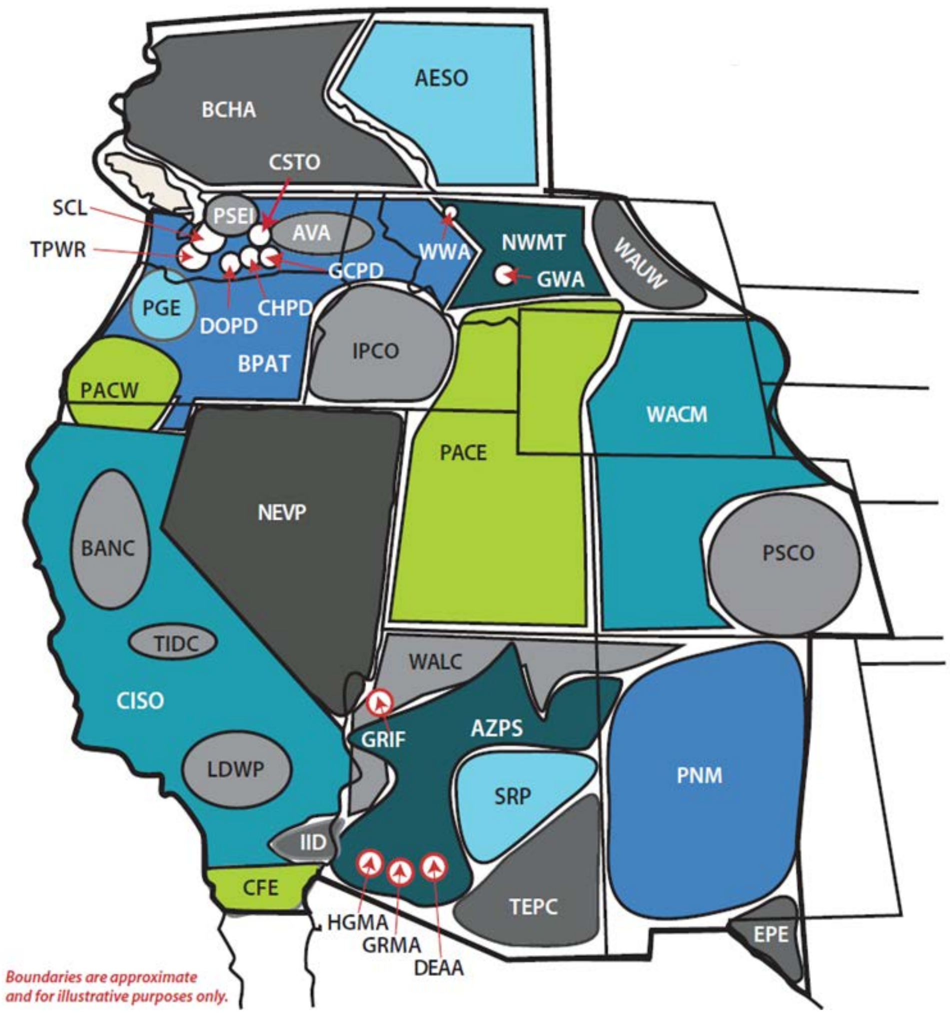
- Introductions
- EIM Update
- Price Curve Scenarios
- Portfolio Development Draft Results
- *Lunch Break (1/2 hour) 11:30 PT/12:30 MT*
- Portfolio Development Draft Results

2015
Integrated Resource Plan

PacifiCorp – CAISO
Energy Imbalance Market - Update

PACIFICORP
Rocky Mountain Power
Pacific Power
PacifiCorp Energy

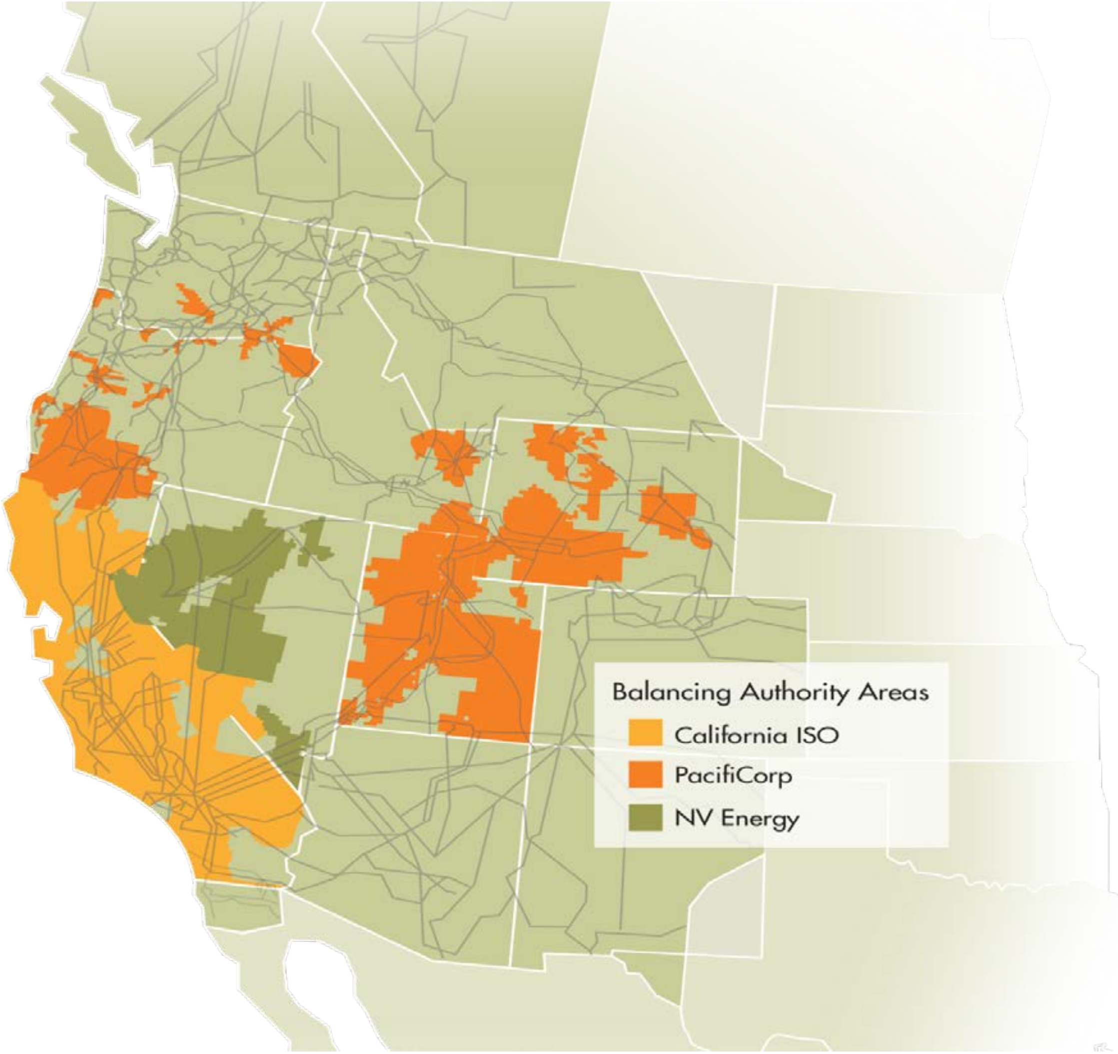
Operational Challenges Resulting From 38 Balancing Authorities in Western Interconnection



Source: Western Electricity Coordinating Council 3.4.14

- Sept. 8, 2011 Southwest outage highlighted shortcomings in operations planning and real-time situational awareness
- No trading between balancing authorities intra-hour results in inefficiencies and higher costs to customers
- Barrier to transition from baseload resources to variable energy resources

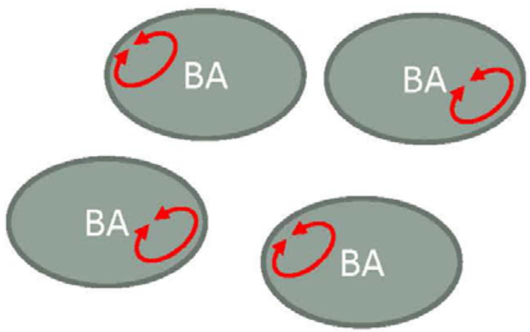
Initial EIM Footprint
(PacifiCorp 2014, NV Energy 2015)



- Co-optimized, automated, 5-minute economic dispatch across the EIM footprint.
- Large geographic, temporal & resource diversity.
- Benefits include reduced costs to serve customers, improved situational awareness, and more effective integration of renewables.

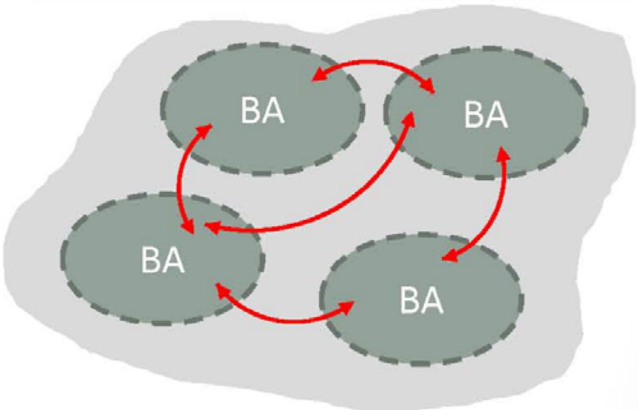
What Does the EIM Do?

Today:
Each BA must balance loads and resources **w/in its borders.**



- Limited pool of balancing resources
- Inflexibility
- High levels of reserves
- Economic inefficiencies
- Increased costs to integrate wind/solar

In an EIM:
The market dispatches resources across BAs to balance energy



- Diversity of balancing resources
- Increased flexibility
- Decreased levels of reserves
- More economically efficient
- Decreased integration costs

Source: Presentation of Commissioner Travis Kavulla (MT), PUC EIM Group Chair, UBS Conference Call, Jan 31, 2014

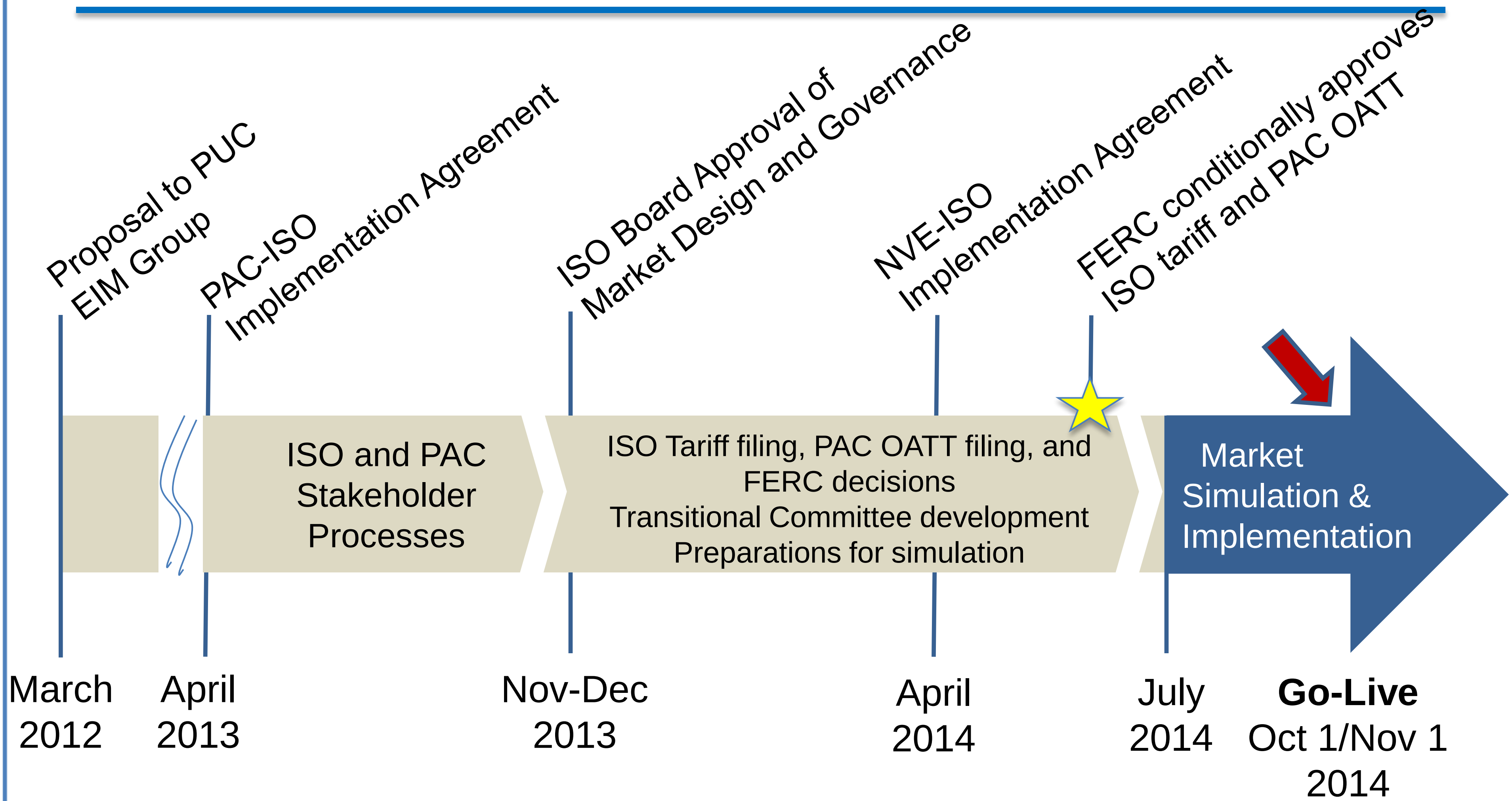
March 2013 E3 Study

PacifiCorp Attributed EIM Benefits
(million 2012$)

Benefit Category	Low transfer capability		Medium transfer capability		High transfer capability	
	Low Range	High Range	Low Range	High Range	Low Range	High Range
Interregional dispatch	$ 7.0	$ 5.5	$ 11.2	$ 8.9	$ 11.2	$ 8.9
Intraregional dispatch	$ 2.3	$ 23.0	$ 2.3	$ 23.0	$ 2.3	$ 23.0
Flexibility reserves	$ 1.2	$ 6.1	$ 3.2	$ 14.9	$ 3.9	$ 22.5
Renewable curtailment	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
Total benefits	**$ 10.5**	**$ 34.6**	**$ 16.7**	**$ 46.8**	**$ 17.4**	**$ 54.4**

Note: Attributed values may not match totals due to independent rounding.

EIM History and Timeline



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FERC Tariff Filing and Order

- FERC has provided broad acceptance of all EIM operational provisions in the ISO and PacifiCorp tariffs
- FERC accepted BPA/ISO agreement revisions for 15-minute EIM Transfers
- BPA coordination continues related to California-Oregon Intertie ("COI") Dynamic Transfer Capability ("DTC") limits
- The ISO petitioned FERC for a temporary lowering of the price cap for initial 90 day startup period

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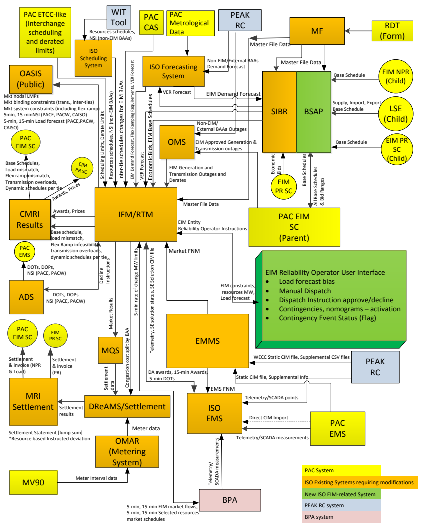
Market Activation Update

- On October 1, 2014, ISO and PacifiCorp systems began in real-time EIM parallel operation (non-binding).
- The EIM became fully operational (and binding) EIM, November 1, 2014.
- Continued actions taken to tune the model, ensure data integrity and provide enhanced tools for the EIM Entity.



EIM Transitional Committee

STEP 1 | **STEP 2**

Stakeholder Transitional Committee

Structure and Operation

- Advisory committee to ISO Board
- 9-11 members
- Open meeting policy

Roles:

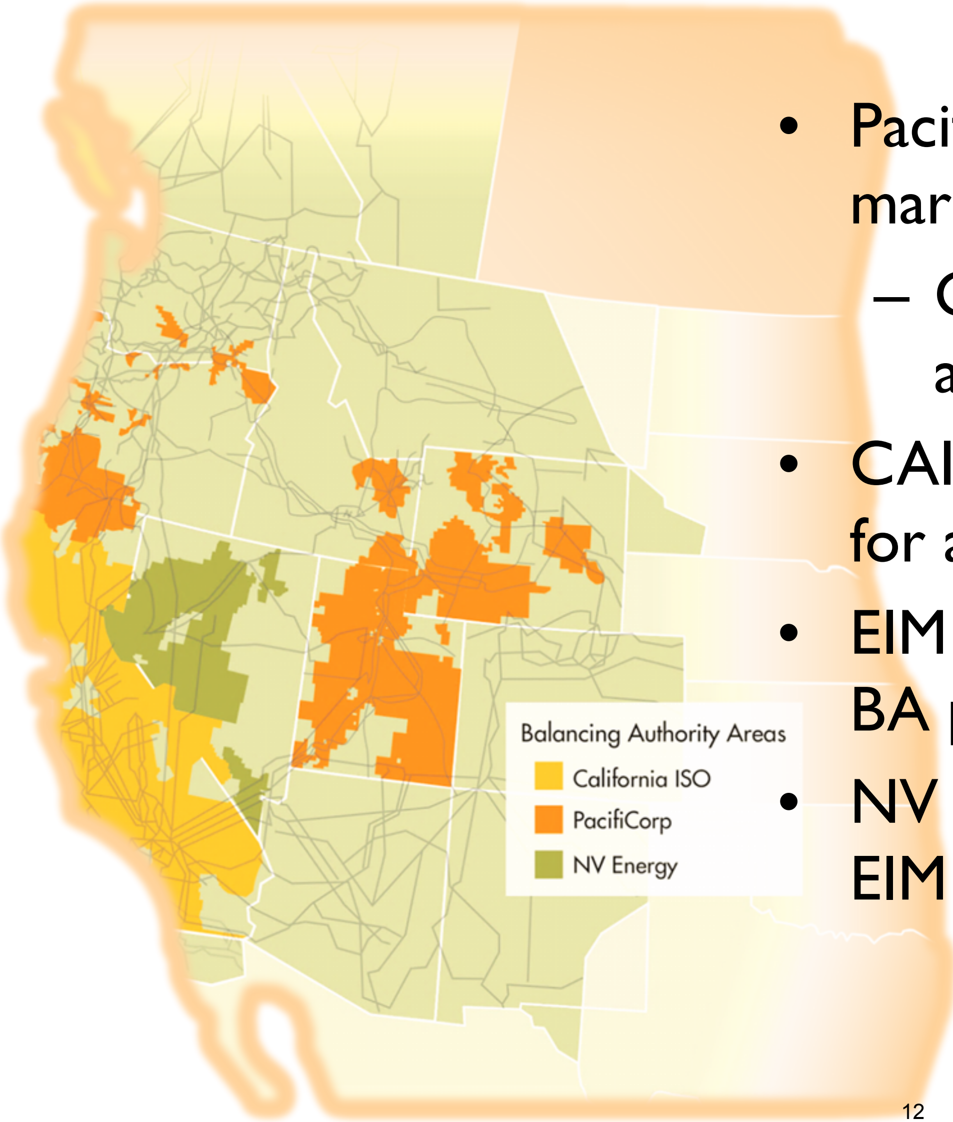
- Participate in ISO stakeholder process on early EIM matters
- Propose independent EIM governance structure

Anticipated Public Stakeholder Process:

- February 2015 – Committee to post “straw proposal”
- Stakeholder process anticipated through August 2015

Independent EIM Governance Structure

Prospects for EIM Expansion



- PacifiCorp is supportive of broader market coordination
  - Greater regional coordination is a priority in the West
- CAISO approach is highly scalable for added participation
- EIM design intended to encourage BA participation
- NV Energy scheduled to join the EIM starting October 2015

2015 Integrated Resource Plan

Price Curve Scenarios

PACIFICORP
Rocky Mountain Power
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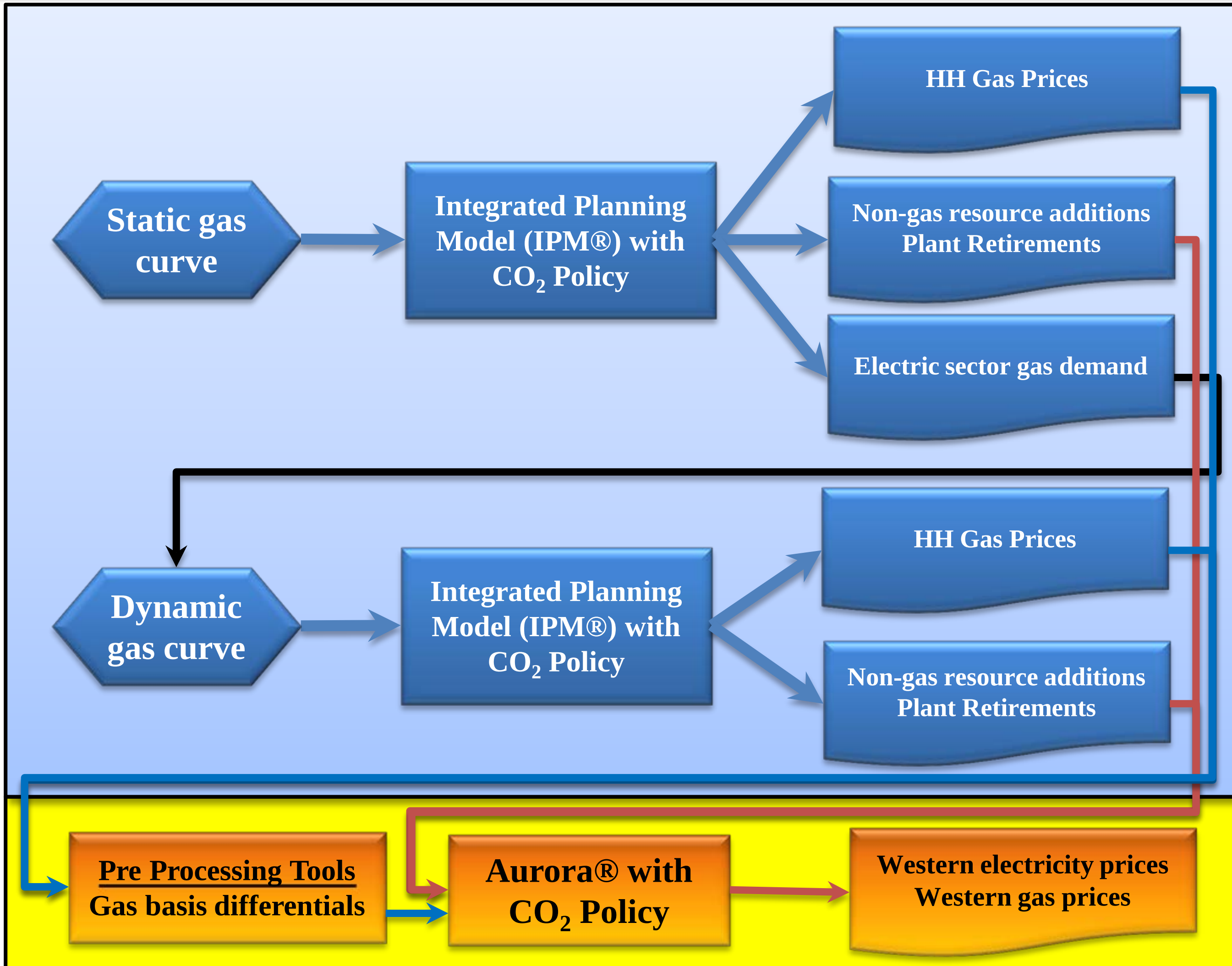
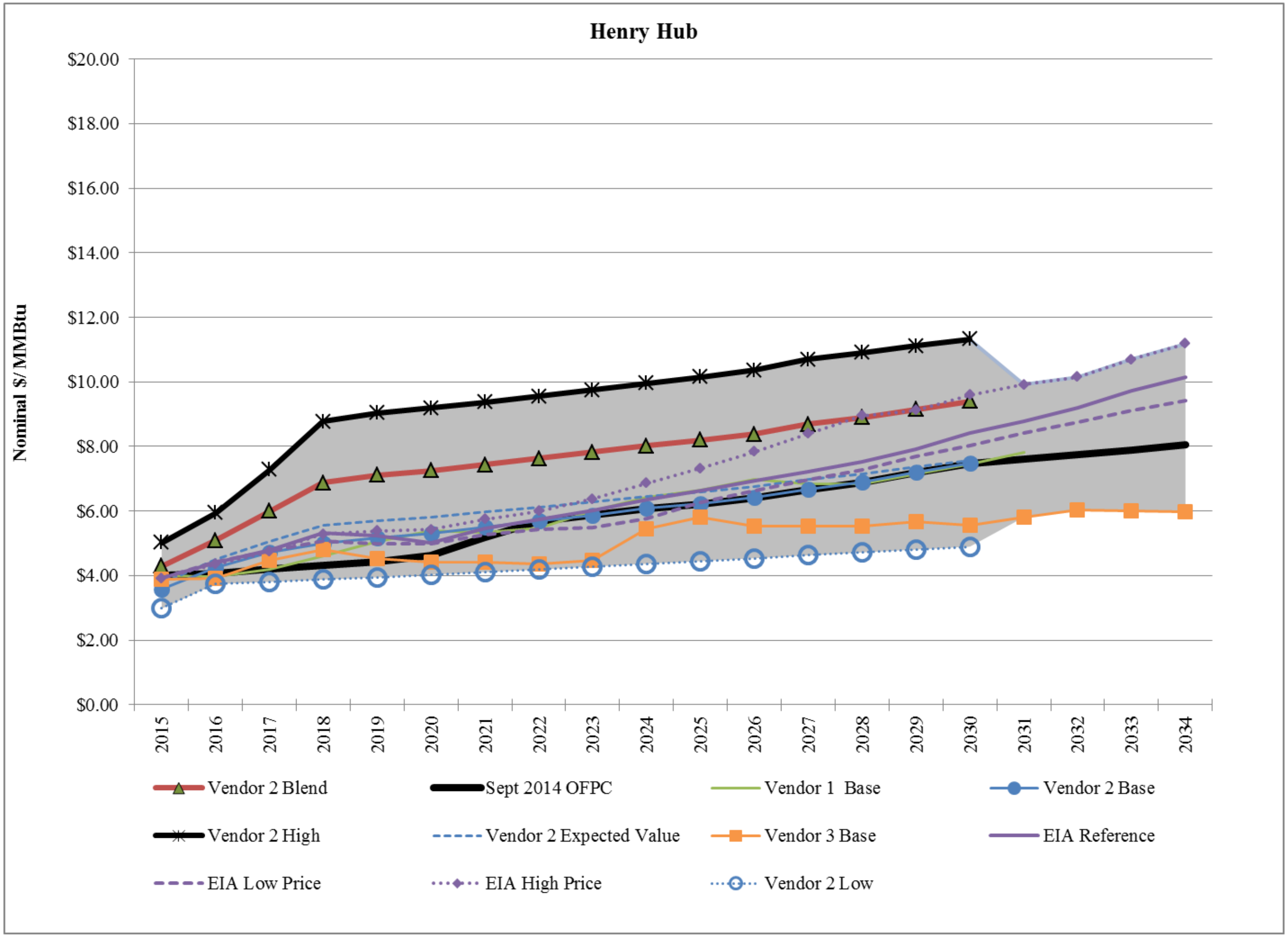
PacifiCorp Energy

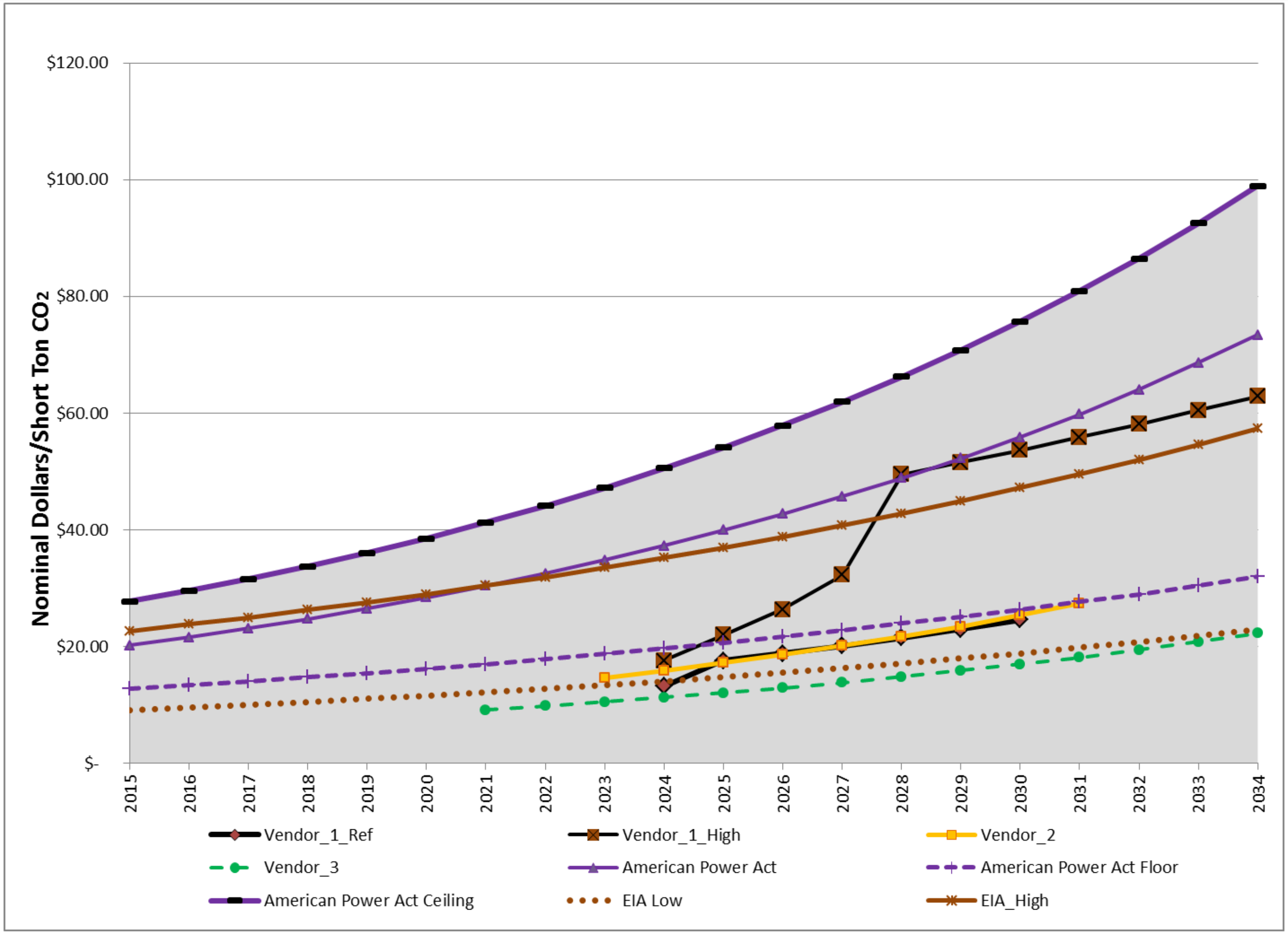
Price Scenarios – Modeling Convention



Survey of Forecasts – Natural Gas



Survey of Forecasts – CO_2



Price Scenarios – 2015 IRP

Scenario	Portfolio Development Cases	PaR Studies	Natural Gas	Power
Sep 2014 OFPC/111(d)	C02 through C13; Sensitivities, but for S-11	Yes	Sep 2014 OFPC (72-months market; 12-months blend; fundamentals per Vendor 2 base)	Sep 2014 OFPC (72-months market; 12-months blend; fundamentals per Aurora forecast)
Base Gas/No CO_2 Policy and No 111(d)	C01	No	Sep 2014 OFPC through 2018; 12-months blend; fundamentals per Vendor 2 base	Sep 2014 OFPC through 2018; 12-months blend; fundamentals per Aurora forecast
Base Gas/111(d)+Stakeholder CO_2 Price	C14, C14a	No	Sep 2014 OFPC gas adjusted for increased electric sector demand	Fundamentals all months per Aurora forecast
Low Gas/111(d)	n/a	Yes	Fundamentals all months per Vendor 2 low case	Fundamentals all months per Aurora forecast
High Gas/111(d)	n/a	Yes	Fundamentals all months per Vendor 2 blend	Fundamentals all months per Aurora forecast
Base Gas/111(d)+High Stakeholder CO_2 Price	S-11	Yes	Sep 2014 OFPC gas adjusted for increased electric sector demand	Fundamentals all months per Aurora forecast

OFPC – Official Forward Price Curve

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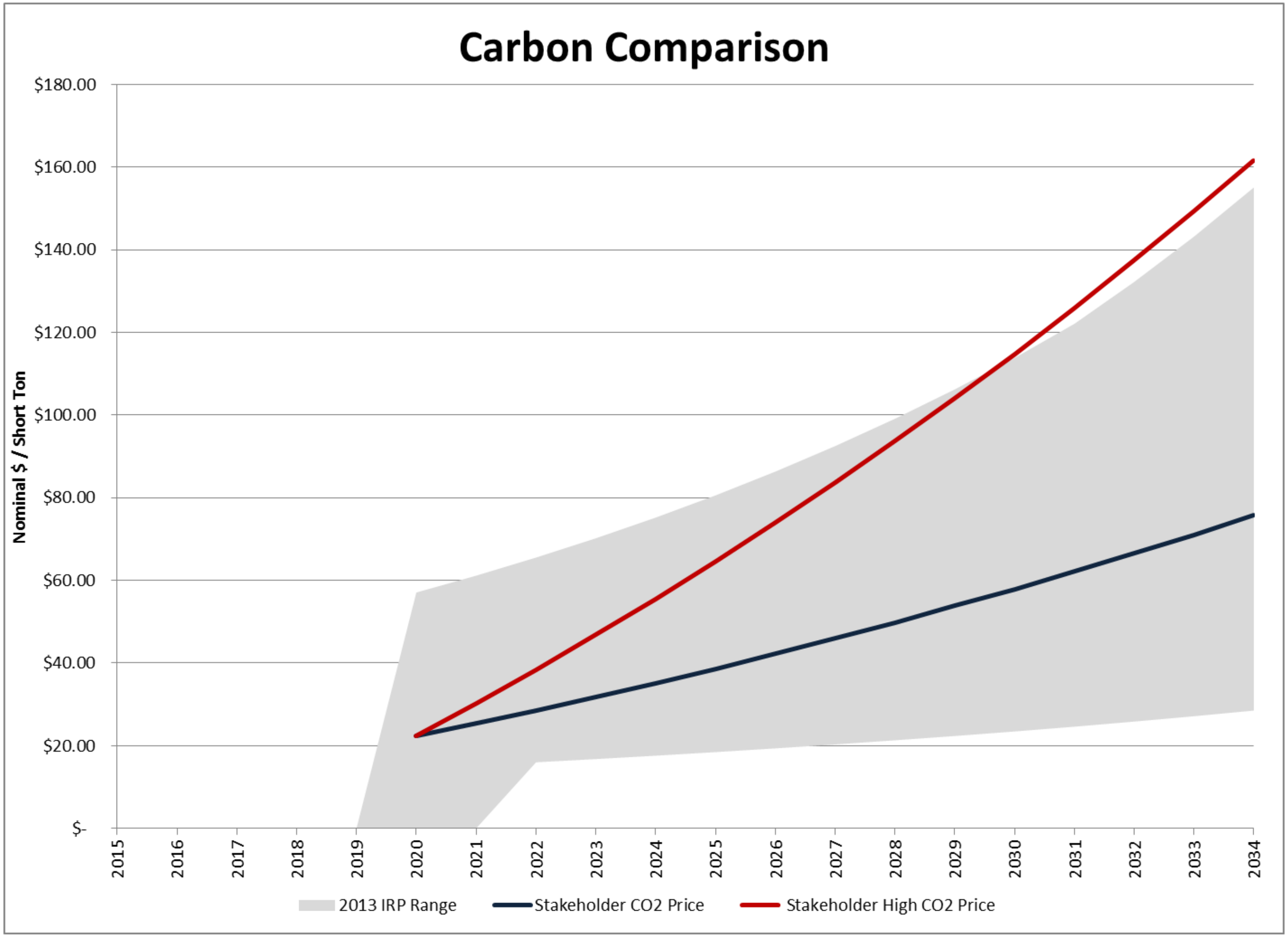
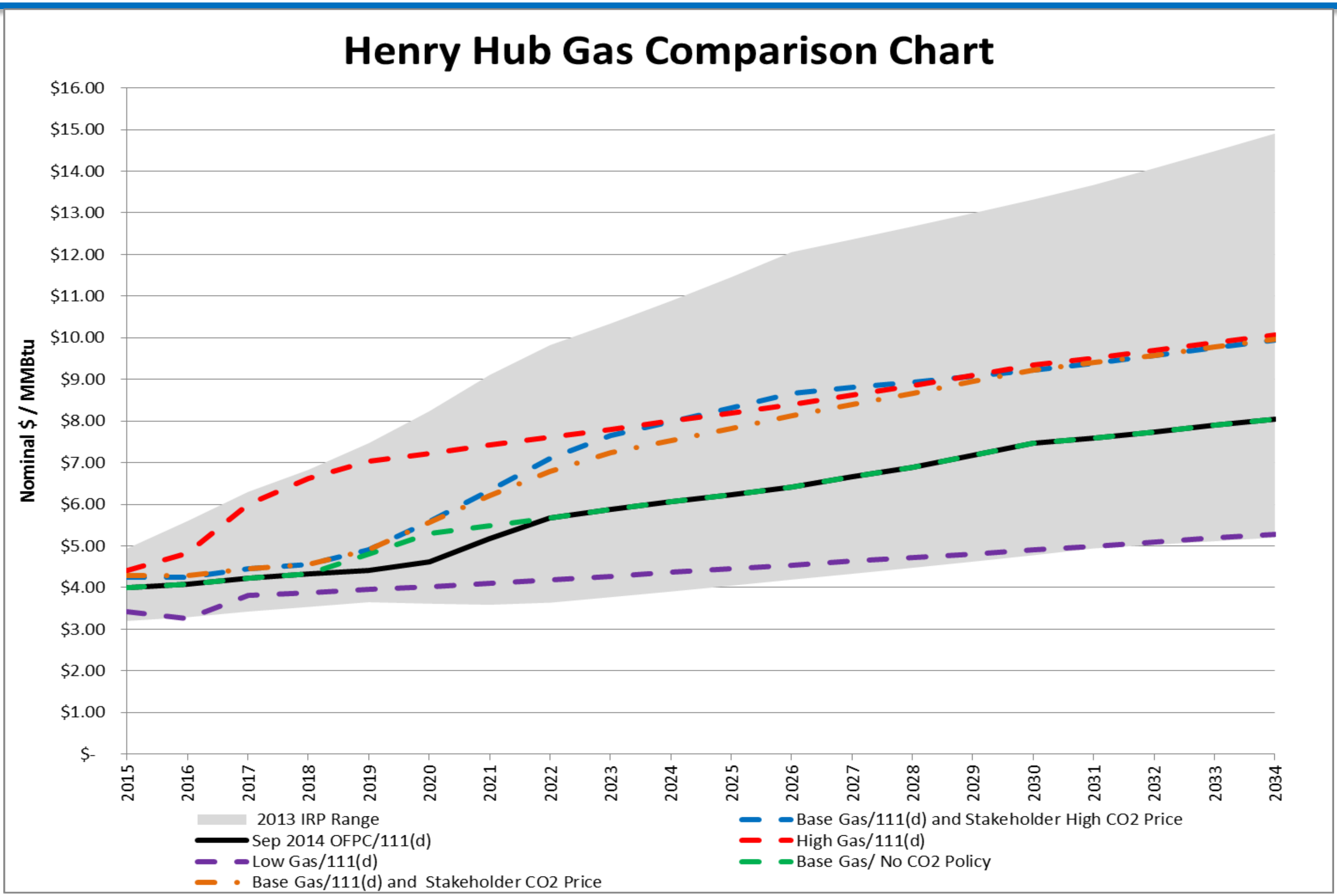
Carbon Comparison – 2015 IRP vs. 2013 IRP

Exhibit JIF-3
OCC Cause No. PUD 201400229

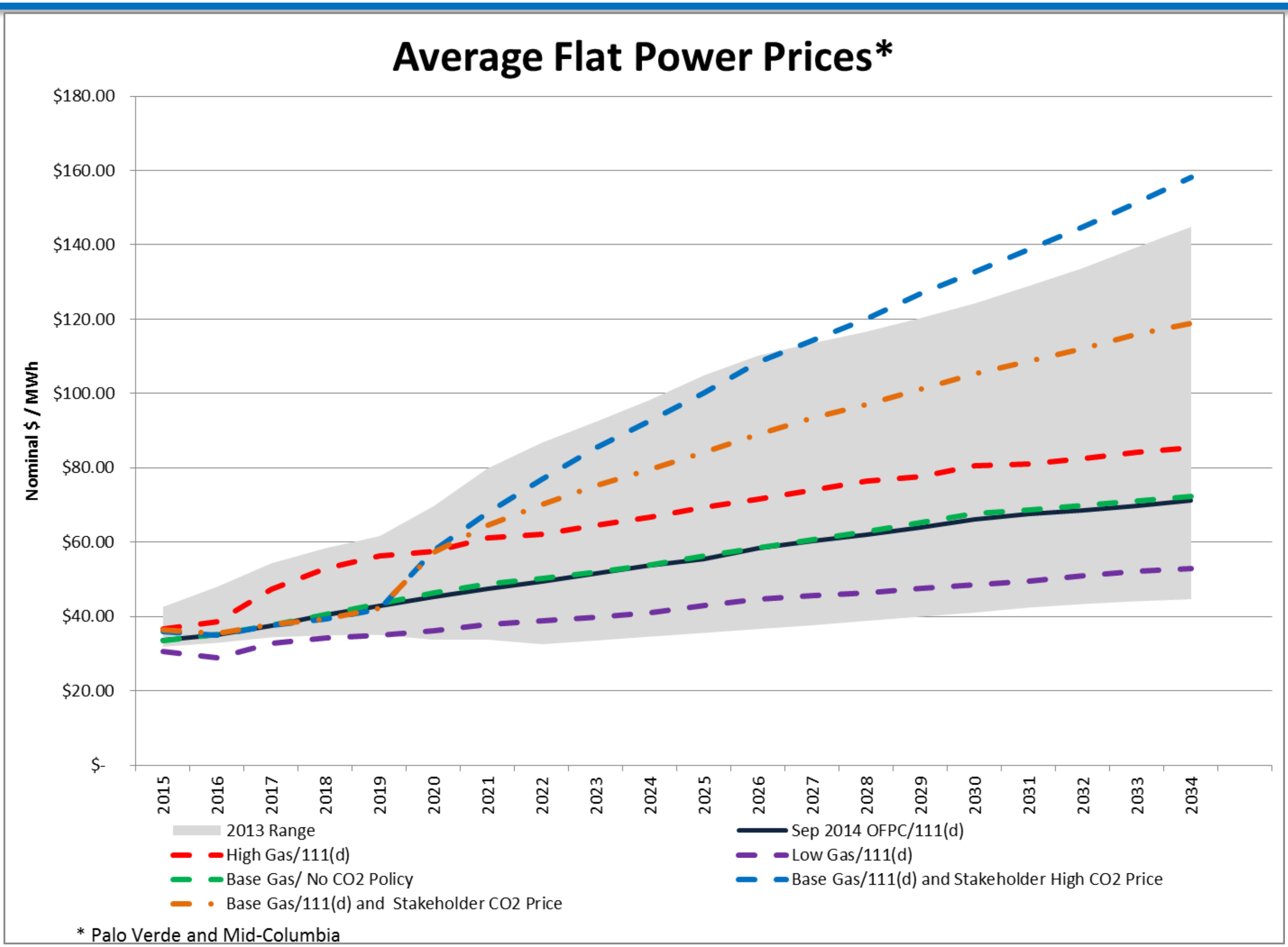


Henry Hub Gas Price Comparison – 2015 IRP vs. 2013 IRP

Exhibit JIF-3
OCC Cause No. PUD 201400229



Power Price Comparison – 2015 IRP vs. 2013 IRP



2015 Integrated Resource Plan

Portfolio Development Cases

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Portfolio Development Highlights

- PacifiCorp has completed its initial resource portfolio modeling, and draft results among 30 different cases have been summarized – additional review of these findings will continue as stochastic risk analysis of the resource portfolios begins.
- EPA's proposed 111(d) emission rate targets for states in which PacifiCorp owns fossil generation and serves retail customers can be met with re-allocation of existing system renewable resources, cost-effective energy efficiency, and limited re-dispatch of existing fossil units.
- Cases that assume EPA's proposed emission rate targets are met with system renewable resources for those states where PacifiCorp owns fossil generation but does not serve retail customers will inform PacifiCorp's acquisition path analysis in the 2015 IRP and on-going discussions with stakeholders in these states to identify acceptable 111(d) compliance plans.
- 111(d) compliance strategies that target cost effective energy efficiency resources and that prioritize re-dispatch of existing fossil generation are lower cost than strategies with increased, higher cost energy efficiency acquisition and/or that prioritize acquisition of new renewable generating assets.
- Nonetheless, opportunities to acquire low-cost renewable resources and low-cost energy efficiency will mitigate 111(d) compliance risks.
- With many portfolios showing resource needs are largely met with incremental acquisition of energy efficiency and front office transactions (FOTs) through the front ten years of the planning horizon, the Company will need to continue to monitor market conditions to ensure there is adequate market supply over time.
- Depending on the case, new renewables may be needed beginning 2020 for RPS compliance; however, lower cost unbundled REC alternatives will be analyzed before selecting the 2015 IRP preferred portfolio.
- In the latter half of the twenty year planning horizon, uncertainties around Regional Haze and green house gas policy drive variability in resource mix among the cases.

Portfolio Development Update

- 50 System Optimizer runs required to develop 30 resource portfolios.
- Draft results have been completed for each core case.
  - Completed cases meet assumed111(d) compliance obligations and state RPS compliance obligations, as applicable.
  - Completed cases reflect estimated costs for new resource transmission integration costs and transmission reinforcement costs, as applicable.
- Core Case Fact Sheets (handout)
  - Documents key input assumptions for each case.
  - Documents draft results for each case (*New!*).
    - PVRR System Costs
    - Resource Portfolio Summary
    - System CO_2 Emissions
    - 111(d) Compliance Profile, as applicable
  - Notice will be sent via the IRP Mailbox when spreadsheet results are posted to the IRP website.

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Core Case Definitions

Case	111(d) Rule	111(d) Compliance Priority	CO_2 Price	FOTs	Price Curve
C01	None	None	None	Base	Base/No 111(d)
C02	All States, Emis. Rate	Re-dispatch + Base EE	None	Base	Sep 2014 OFPC
C03	All States, Emis. Rate	Re-dispatch + Inc. EE	None	Base	Sep 2014 OFPC
C04	All States, Emis. Rate	Renewable + Inc. EE	None	Base	Sep 2014 OFPC
C05	Retail States, Emis. Rate	Re-dispatch + Base EE	None	Base	Sep 2014 OFPC
C05a	Retail States, Emis. Rate	Re-dispatch + Base EE	None	Base	Sep 2014 OFPC
C06	Retail States, Emis. Rate	Re-dispatch + Inc. EE	None	Base	Sep 2014 OFPC
C07	Retail States, Emis. Rate	Re-dispatch + Inc. EE	None	Base	Sep 2014 OFPC
C09	Retail States, Emis. Rate	Re-dispatch + Base EE	None	Limited	Sep 2014 OFPC
C11	Retail States, Emis. Rate	Re-dispatch + Acc. EE	None	Base	Sep 2014 OFPC
C12	Mass Cap, New+Existing	None	None	Base	Sep 2014 OFPC
C13	Mass Cap, Existing	None	None	Base	Sep 2014 OFPC
C14	Retail States, Emis. Rate	Re-dispatch + Base EE	Yes	Base	Base/CO2 Adjusted
C14a	Retail States Emis. Rate	Re-dispatch + Base EE	Yes	Base	Base/CO2 Adjusted

- Cases C01 and C05a are replicated among three different Regional Haze Scenarios.
- All other cases are replicated among two different Regional Haze Scenarios.

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Case Definition Updates

- Cases C05 through C07
  - No longer assume physical allocation of renewable resources by state boundary (not likely).
  - A key 111(d) uncertainty is how states might address fossil generation that does not serve retail load in the state, and the Company continues to engage with parties in these states to identify acceptable 111(d) compliance plans (i.e. reflecting PacifiCorp's plans to stop operating Cholla Unit 4 as a coal-fired asset by the end of 2024).
  - Consequently, cases C05 through C07 are defined as variants of cases C02 through C04 by removing Arizona, Colorado, and Montana from PacifiCorp's 111(d) compliance solution.
  - Cases C02 through C04 will inform PacifiCorp's 2015 IRP acquisition path analysis and continued discussions with stakeholders in these states.

- Cases C08 and C10 were eliminated (both assumed physical allocation of renewable resources by state boundary).

- Cases C09 (constrained FOTs) and C11 (accelerated DSM) are aligned with 111(d) assumptions per Case C05.

- Based on stakeholder feedback, Case C13 was added (note, the previous Case C13 has been renamed as Case C14) to provide a second mass cap case applicable to only existing fossil resources.

- Added alternatives to Cases C05 and C14
  - Cases C05a-1 and C05a-2 were added to analyze an Oregon unbundled REC RPS compliance strategy.
  - Upon reviewing Regional Haze retirement assumptions on the timing of new resources, Case C05a-3 was added to replicate the Oregon RPS unbundled REC strategy with alternative coal retirement assumptions.
  - Case C14a replicates Case C14, but allows endogenous retirement of coal units not already assumed to have an early retirement date under the applicable Regional Haze Scenario.

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Regional Haze Scenarios

Coal Unit	Reference	RH-1	RH-2	RH-3
Dave Johnston 1	Shut Down Dec 2027	Shut Down Mar 2019	Shut Down Mar 2019	Shut Down Dec 2027
Dave Johnston 2	Shut Down Dec 2027	Shut Down Dec 2027	Shut Down Dec 2023	Shut Down Dec 2027
Dave Johnston 3	SCR by Mar 2019; Shut Down Dec 2027	Shut Down Dec 2027	Shut Down Dec 2027	Shut Down Dec 2027
Dave Johnston 4	Shut Down Dec 2027	Shut Down Dec 2032	Shut Down Dec 2032	Shut Down Dec 2027
Hunter 2	SCR by Dec 2021	Shut Down by Dec 2032	Shut Down by Dec 2024	Shut Down by Dec 2032
Huntington 1	SCR by Dec 2022	Shut Down by Dec 2036	Shut Down by Dec 2024	SCR by Dec 2022
Huntington 2	SCR by Dec 2022	Shut Down by Dec 2021	Shut Down by Dec 2021	Shut Down by Dec 2029
Jim Bridger 1	SCR by Dec 2022	Shut Down by Dec 2023	Shut Down by Dec 2023	SCR by Dec 2022
Jim Bridger 2	SCR by Dec 2021	Shut Down by Dec 2032	Shut Down by Dec 2028	SCR by Dec 2021
Wyodak	SCR by Mar 2019	Shut Down by Dec 2039	Shut Down by Dec 2032	Shut Down by Dec 2039

Common to All Scenarios:
Carbon 1&2 shutdown 2015; Cholla 4 gas conversion 2025; Colstrip 3&4 SCR 2023/2022, respectively; Craig 1&2 SCR 2021/2018, respectively; Hayden 1&2 SCR 2015/2016, respectively; Naughton 1&2 shutdown 2029; Naughton 3 gas conversion 2018, shutdown 2029; Hunter 1&3 SCR 2021/2024, respectively; and Bridger 3&4 SCR 2015/2016, respectively

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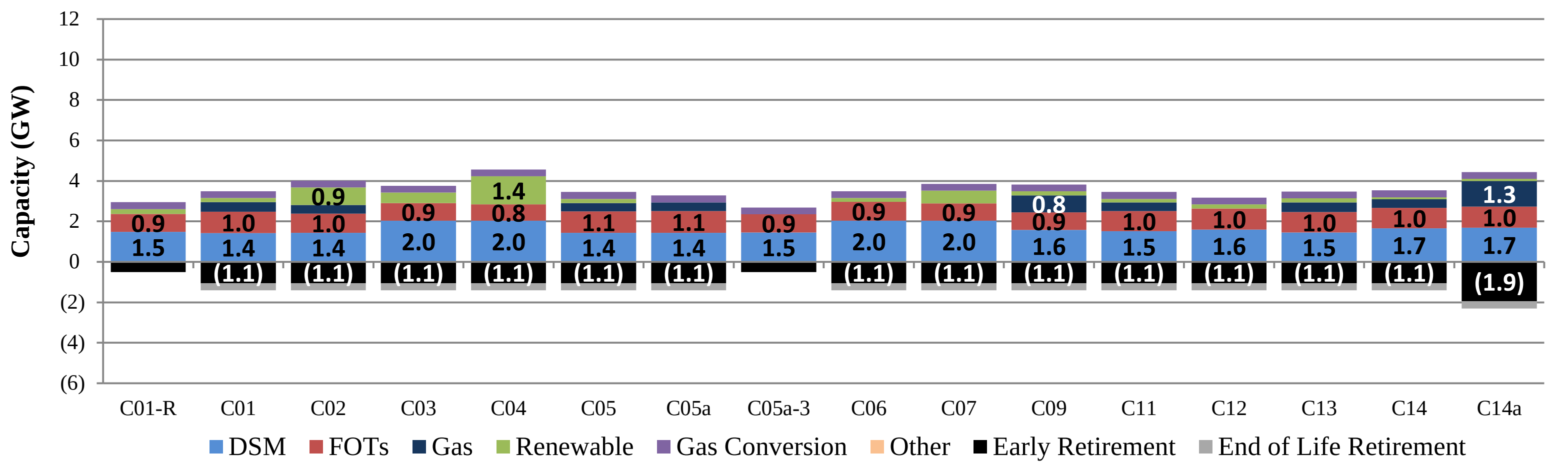
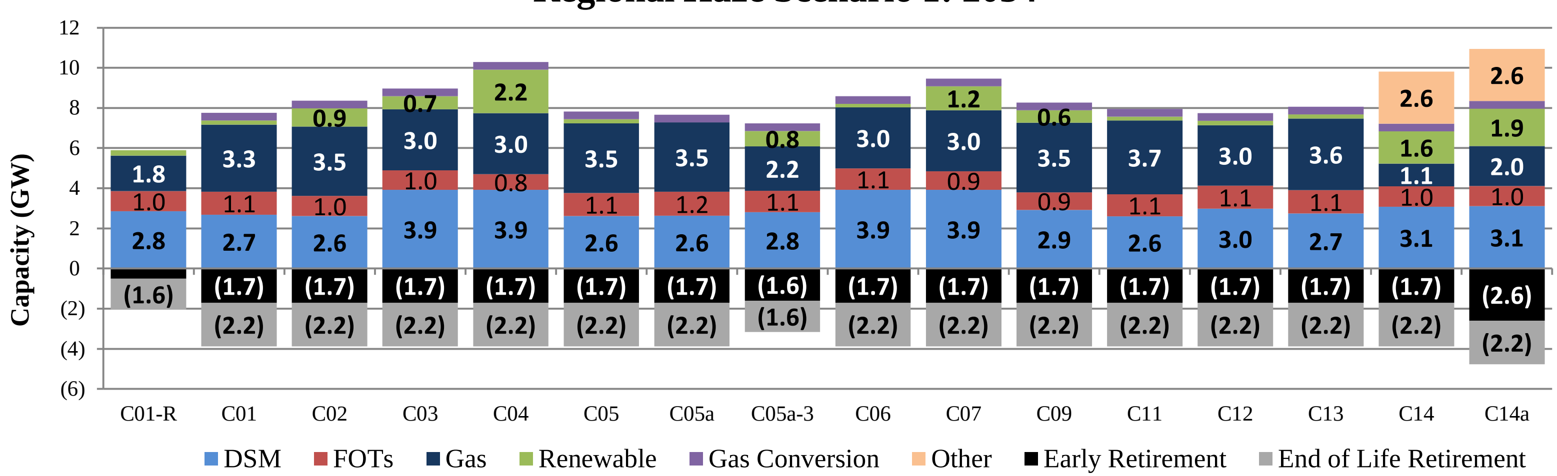
Portfolio Snapshot: RH-1*

Regional Haze Scenario 1: 2024



Regional Haze Scenario 1: 2034



*Note: Cases C01-R and C05a-3 reflect the Reference and RH-3 Regional Haze Scenarios, respectively. “Other” in Cases C14 and C14a is comprised of East modular nuclear.

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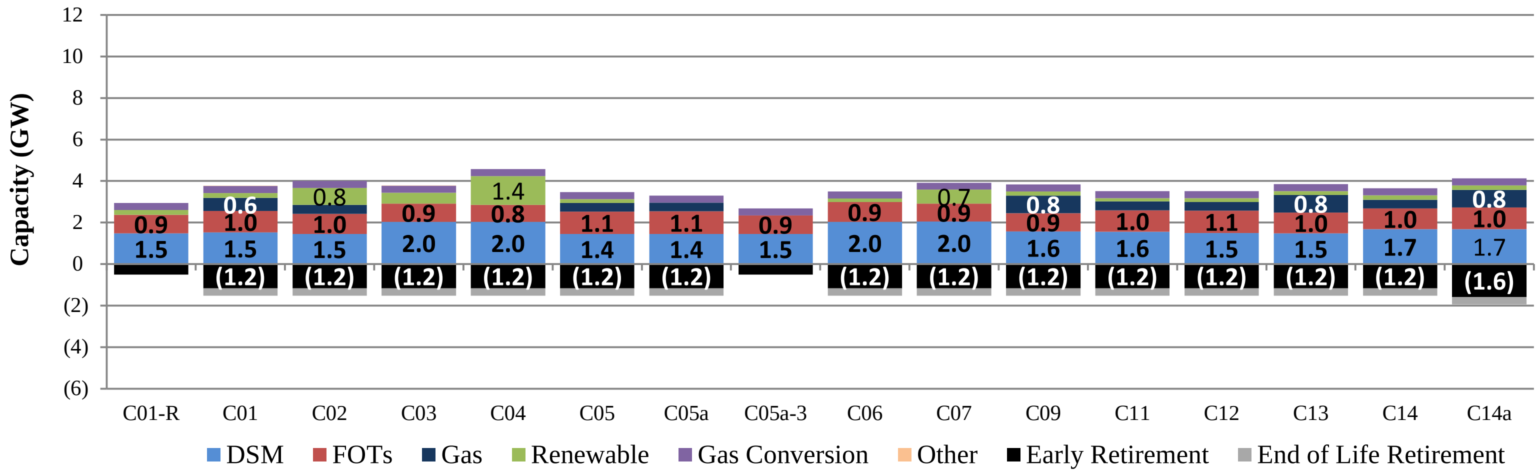
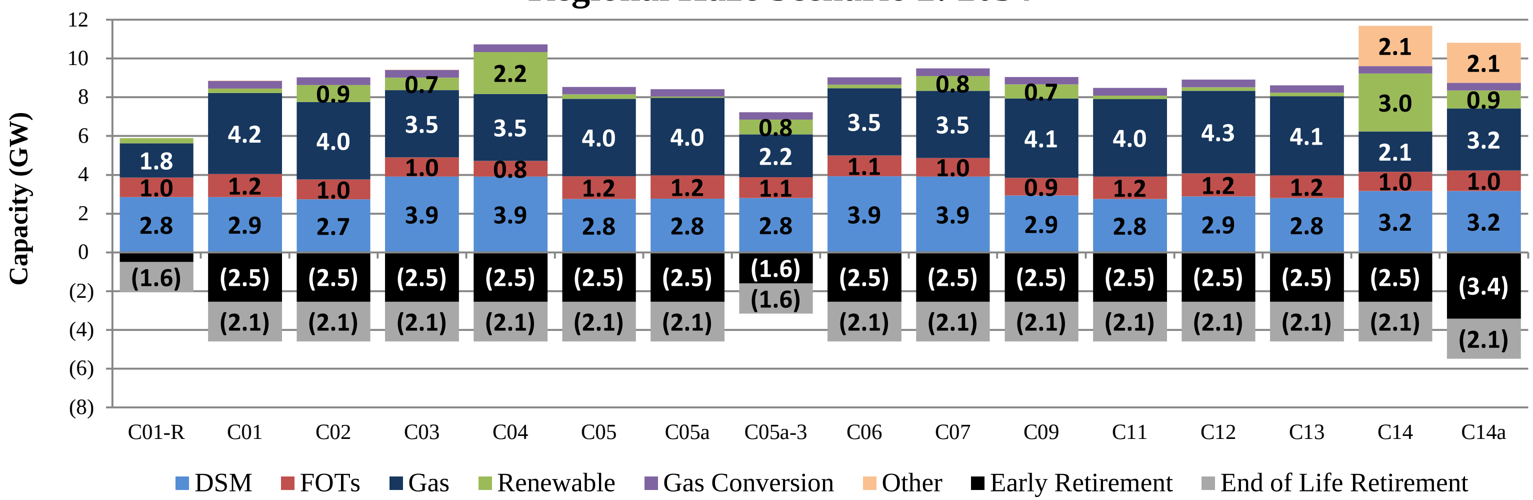
Portfolio Snapshot: RH-2*

Regional Haze Scenario 2: 2024



Regional Haze Scenario 2: 2034



*Note: Cases C01-R and C05a-3 reflect the Reference and RH-3 Regional Haze Scenarios, respectively. "Other" in Cases C14 and C14a is comprised of East modular nuclear.

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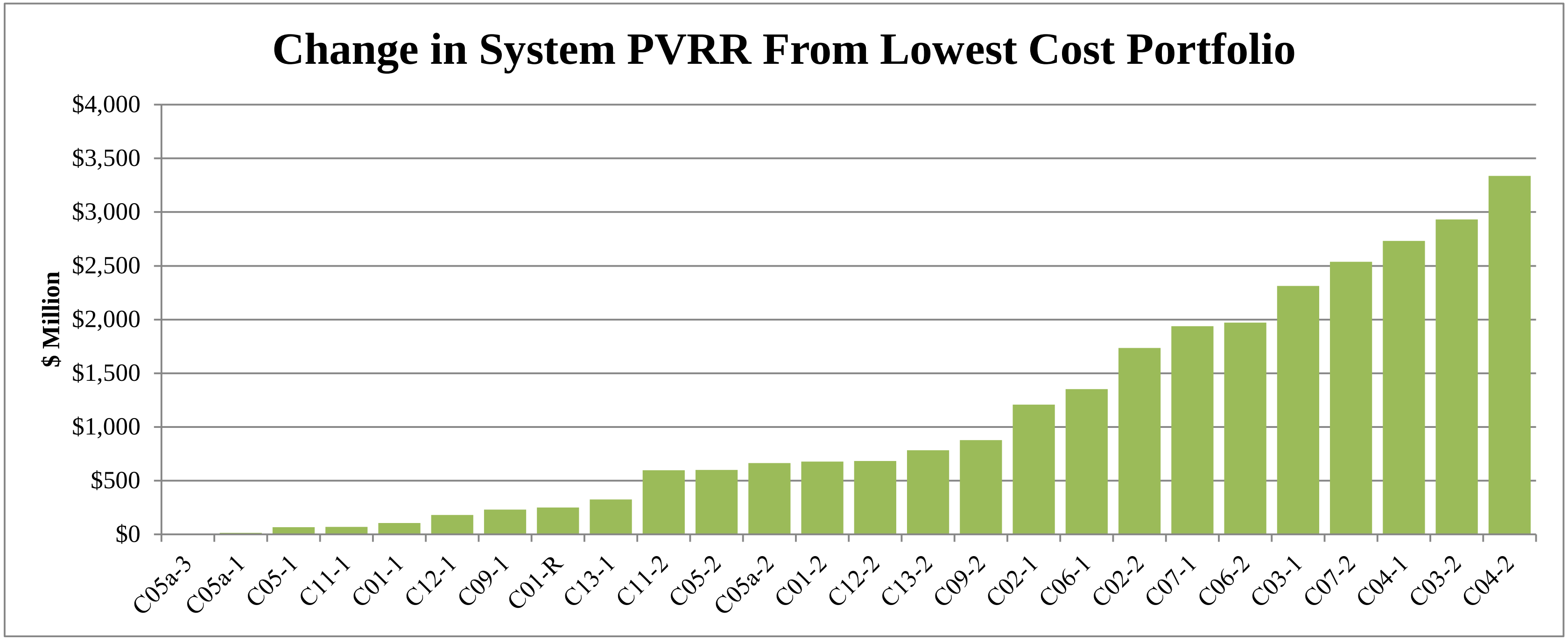
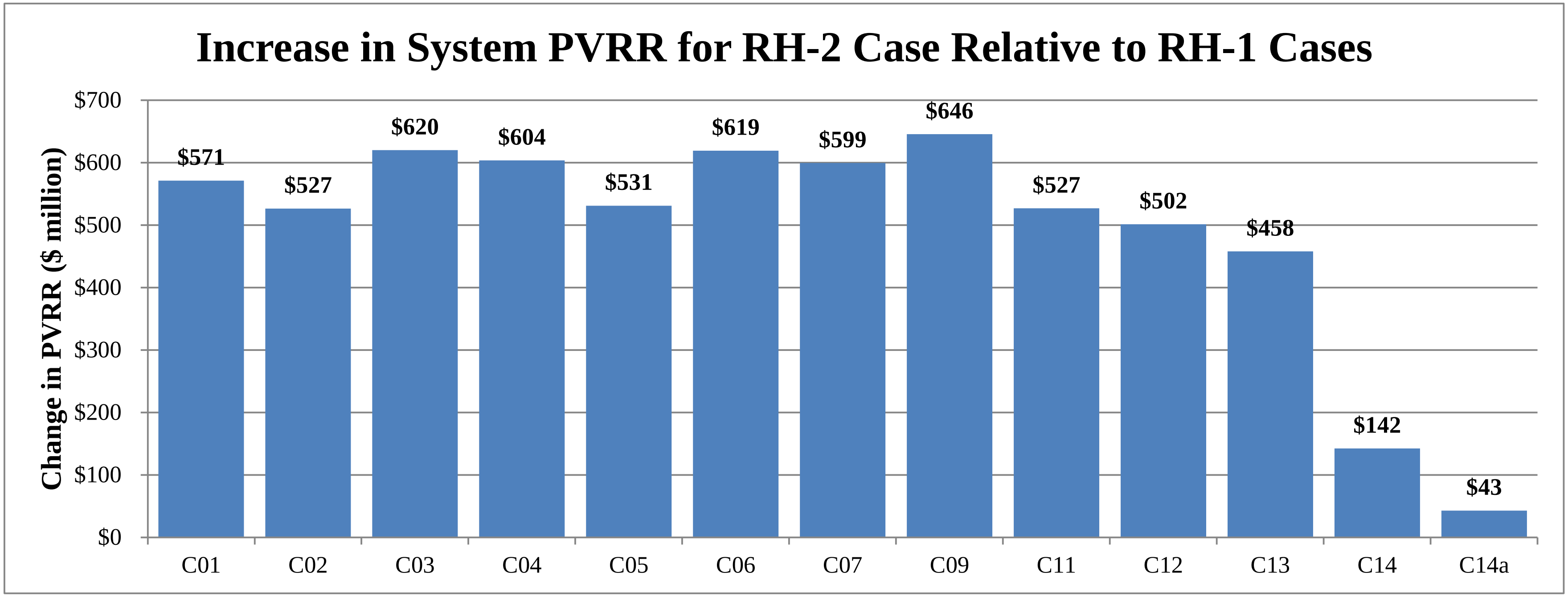
Relative Portfolio System Costs



- Based on System Optimizer results, Case C05a-3 is the lowest cost portfolio.
- Cases C05a-1, C05-1, and C11-1 are all within $100m of Case C05a-3.
- Cases C14 and C14a are not shown in the figure above – these cases are between $12.7 billion and $13.0 billion higher cost than Case C05a-3.
- Mean PVRR costs, risk-adjusted PVRR costs, and other cost and risk metrics will be assessed using PaR to inform the preferred portfolio selection process.

Regional Haze System Cost Impacts: RH-2 as Compared to RH-1



- In Cases C01 through C13, Regional Haze Scenario 2 portfolio costs are between $458 million to $646 million higher than Regional Haze Scenario 1 portfolio costs.

- With CO_2 prices assumed applicable to Cases C14 and C14a, CO_2 expenses largely overshadow the relative cost differential between Regional Haze Scenarios.

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111(d) Compliance Overview

	All States (C02-1, C03-1, C04-1)	Retail States (C05-1, C06-1, C07-1)
Strategy A (C02-1 & C05-1)	• New East NGCCs • Base EE • Backdown of West NGCCs • Backdown of WY, AZ, CO, MT Coal • New RE = 866 MW 2020-2021, 37 MW in 2030 for OR RPS	• New East NGCCs • Base EE • Backdown of West NGCCs • No Coal Backdown • New RE = 206 MW 2020-2024 for OR RPS
Strategy B (C03-1 & C06-1)	• New East NGCCs • Inc. EE (Up to 1.5% of sales) • Backdown of West NGCCs • Backdown of WY, AZ, CO, MT Coal • New RE = 511 MW in 2020, 144 MW in 2030 for OR RPS	• New East NGCCs • Inc. EE (Up to 1.5% of sales) • Backdown of West NGCCs • No Coal Backdown • New RE = 175 MW 2020-2022 for OR RPS
Strategy C (C04-1 & C07-1)	• New East NGCCs • Inc. EE (Up to 1.5% of sales) • Backdown of West NGCCs • Backdown of AZ & CO Coal • New RE = 2,161 MW 2020-2029; no additional for OR RPS	• New East NGCCs • Inc. EE (Up to 1.5% of sales) • No West NGCC Backdown • No Coal Backdown • New RE = 1,197 MW 2020-2031; no additional for OR RPS

- Strategy A = Flexible allocation of system RE and ID/CA EE; base cost effective selection of EE; prioritize fossil re-dispatch (coal at 7-months effective full load operation) before adding new system renewables
- Strategy B: Flexible allocation of system RE and ID/CA EE; incremental EE of up to 1.5% of retail sales forced; prioritize fossil re-dispatch (coal at 7-months effective full load operation) before adding new system renewables
- Strategy C: Flexible allocation of system RE and ID/CA EE; incremental EE of up to 1.5% of retail sales forced; prioritize new system renewables before re-dispatching fossil

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111(d) Compliance in States with Fossil Generation and No Retail Customers

- Comparison of Cases C02 through C04 with Cases C05 through C07 provide an opportunity to understand the implications of a critical 111(d) uncertainty, which is how states might address fossil generation that does not serve retail load in the state.
- Application of state emission rate targets to PacifiCorp's share of fossil generation in these states places disproportionate compliance burden on PacifiCorp customers that is not reasonable.
- Assuming PacifiCorp meets its share of emission rate targets in AZ, CO, and MT with re-dispatch, with flexible allocation of system renewable resources, and with flexible allocation of and ID/CA energy efficiency, the present value revenue requirement of system costs is increased by $0.8 billion to $1.1 billion when compared to those cases that remove these states from the 111(d) compliance solution.
- These cases will inform PacifiCorp's acquisition path analysis in the 2015 IRP and will inform on-going engagements with these states to find workable and equitable compliance solutions – these cases highlight the following:
  - Compliance costs will be mitigated by obtaining relief in achieving interim emission rate targets, which would account for early action like PacifiCorp's proposed plans to cease operating Cholla 4 as a coal fired facility by the end of 2024.
  - Compliance costs would be partially mitigated by including situs assigned energy efficiency resources from all states in its multi-state 111(d) compliance strategy.
  - Compliance costs would be partially mitigated if PacifiCorp were able to use 111(d) compliance attributes from all qualifying facility resources, regardless of REC ownership.
  - Compliance costs would be partially mitigated if PacifiCorp applied assumed distributed generation energy across its system toward meeting 111(d) emission rate targets.

Oregon RPS Scenarios

- Case C05 assumes OR RPS requirements will be met with new renewable assets.
  - C05-1 = 154 MW of UT solar in 2020, 25 MW of WY wind in 2020, and 27 MW of OR wind in 2024 (206 total MW)
  - C05-2 = 106 MW of WY wind in 2020, 58 MW of UT solar in 2023, and 12 MW of WY wind in 2024 (176 total MW)
  - In both cases, OR does not have an RPS compliance shortfall until 2029; however, with banking rules, earlier acquisition reduces the future need of situs assigned renewable resources.
- Potentially lower cost solutions may be available for Oregon customers by acquiring unbundled RECs to defer the need to meet RPS requirements with assets beyond the planning horizon.
- Cases C05a-1 and C05a-2 are alternatives to C05-1 and C05-2, respectively, that eliminate situs assigned RPS resources from the portfolio.
- The levelized cost or benefit of meeting Oregon RPS with new generating assets, given current assumptions regarding the draft 111(d) rule, are preliminary assessed by comparing the differential in System Optimizer PVRR costs between Cases C05 and C05a per megawatt-hour of situs assigned Oregon RPS generation removed from the portfolio.

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Levelized Cost/Benefit of Alternative RPS Compliance Cases with Current 111(d) Assumptions

	(Increase)/Decrease in System PVRR with Removal of OR RPS Renewables ($m)	Nominal Levelized (Increase)/Decrease in System Cost PVRR per MWh of OR RPS Renewable Energy Removed ($/MWh)
Case C05-1 less C05a-1	$54.4	$14/MWh
Case C05-2 less C05a-2	($63.1)	($17)/MWh

- Under Regional Haze Scenario 1, system costs are reduced by about $14/MWh of situs assigned Oregon RPS renewable generation when these assets are removed from the portfolio.
- Under Regional Haze Scenario 2, system costs increase by about $17/MWh of situs assigned Oregon RPS renewable generation when these assets are removed from the portfolio.
- Differences between the two scenarios are driven by the interaction of Oregon situs assigned RPS renewable energy with the flexible allocation of system renewable resources to meet 111(d) emission rate goals and the type/location of Oregon situs assigned renewable resources in the C05-1 and C05-2 portfolios.
  - Oregon situs assigned renewable energy is used for Oregon RPS compliance and for Oregon 111(d) compliance.
  - Oregon situs assigned renewable energy is not re-allocated to other states for 111(d) compliance purposes.
  - When situs assigned renewable energy is used for Oregon RPS and 111(d) compliance, this frees up existing system renewable energy that can be allocated to other states for 111(d) compliance purposes.
  - When situs assigned Oregon RPS resources are included in the portfolio, back down of existing Wyoming coal generation is avoided, which mitigates 111(d) compliance costs and offsets potential cost savings of deferring situs assigned Oregon RPS generating assets.
  - In Regional Haze Scenario 1, limited transmission in Wyoming limits low cost Wyoming wind, and the 111(d) compliance benefits are not enough to entirely offset cost savings when Oregon situs assigned renewable resources are removed from the portfolio.
  - In Regional Haze Scenario 2, assumed retirements of Dave Johnston Units 1&2 allows more low cost Wyoming wind, and the 111(d) compliance benefits more than offset cost savings when Oregon situs assigned renewables are removed from the portfolio.
- Additional portfolio analysis of Oregon RPS compliance will be performed to inform preferred portfolio selection in the 2015 IRP.

Reminder - Upcoming Meetings

- 111(d) Scenario Maker Confidential Technical Workshops
  - Two onsite workshops
    - Portland
    - Salt Lake City
  - To be scheduled
- January 29-30, 2015
  - Confidential Coal Analysis
  - Stochastic Results
  - Sensitivity Analysis Results
  - Preferred Portfolio and Action Plan
- February 26, 2015
  - Final Report

Note: meeting topics are tentative and subject to change.

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STATE OF INDIANA

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

SCOTT C. WEAVER

ON BEHALF OF

INDIANA MICHIGAN POWER COMPANY

PRE-FILED VERIFIED DIRECT TESTIMONY OF SCOTT C. WEAVER ON BEHALF OF INDIANA MICHIGAN POWER COMPANY

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION?

A. My name is Scott C. Weaver, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation ("AEPSC") as Managing Director-Resource Planning and Operational Analysis. AEPSC supplies engineering, financing, accounting and similar planning and advisory services to the ten electric operating companies of the American Electric Power System (collectively, "AEP").

II. BACKGROUND

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Business Administration Degree in Accounting from Ohio University in 1981, and a Master of Business Administration from the same university in 1985. In addition, in 1996 I completed both the American Electric Power System Management Development Program at The Ohio State University, as well as The Darden Partnership Program at the Darden Graduate School of Business Administration, at the University of Virginia.

I was employed by AEPSC in 1980 as an Associate Forecast Analyst in the Controllers Department (now Corporate Planning and Budgeting Department), was subsequently named Assistant Financial Analyst in 1983, Financial Analyst in 1986, Senior Financial Analyst in 1987, and Senior Administrative Assistant II in 1990. In 1991, I transferred to the AEPSC Fuel Supply Department as Manager-Administration. I was subsequently named Manager-Administration and Purchasing in 1994 and Director of Power Generation Business Planning and Financial Management in 1996. I transferred to the AEP Wholesale business unit in 2000 as Manager-Business Planning and in January, 2003 transferred back to the Corporate Planning and Budgeting Department as Director of Operational Analysis. I assumed my present position in May 2003.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR–RESOURCE PLANNING AND OPERATIONAL ANALYSIS?

A. I am responsible for the supervision and administration of long-term generation resource planning and supply-side operational analysis for AEP. In such capacity, I coordinate the use of short- and long-term generation production costing and other resource planning models used in the ultimate development of operating and capital budget forecasts for Indiana Michigan Power Company ("I&M", or "the Company") and its parent, AEP, regularly monitor actual performance, and review the preparation of forecasted information for use in regulatory proceedings.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS REGULATORY COMMISSION?

A. Yes. I most recently offered testimony before this Commission in 2013 on behalf of the Company in Cause No. 44331, which sought a certificate of public convenience and necessity ("CPCN") for the installation of dry sorbent injection ("DSI") technology and associated equipment at the Company's Rockport Plant. In addition over the last seven years I will have offered resource planning-related testimony on behalf of AEP operating company affiliates before eight other state commissions: Arkansas, Kentucky, Louisiana, Michigan, Oklahoma, Texas, Virginia, and West Virginia.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS FILING?

A. The purpose of this testimony is to:

1) evaluate the cost and feasibility of an option to retire and replace Rockport Unit 1, an assessment required by Ind. Code § 8-1-8.7-3(b)(7);

2) describe the modeling process undertaken to evaluate the relative economics of the alternative Rockport Unit 1 disposition options, including a discussion around the major input parameters and key drivers; chief among them the anticipated long-term price of natural gas and energy as well as carbon dioxide ("CO_2") that could impact the Rockport Unit 1 dispatch priority, an assessment required by Ind. Code § 8-1-8.7-3(b)(8); and

3) discuss the results of these economic modeling analyses and the determination that a decision in the near-term to **retrofit Rockport Unit 1 by December 31, 2017 with Selective Catalytic Reduction (SCR) technology and associated equipment** for the reduction of NO_X would further a long-term course of action around this unit—which will begin with the installation of DSI technology in 2015, as approved by the Commission in Cause No. 44331—that could ultimately save I&M and its customers more than **$800 million**, in today's dollars, versus retirement/replacement alternatives.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

- Exhibit SCW-1 – Overview of resource planning-related criteria considered in the analyses.
- Exhibit SCW-2 – Key long-term fundamental commodity pricing projections used in the analyses.
- (CONFIDENTIAL) Exhibit SCW-3 – Major modeling input costs and operating parameters for unit disposition options.
- Exhibit SCW-4 – Summary of Rockport 1 unit disposition alternative economic analyses over the long-term, life cycle study period evaluated.
- Exhibit SCW-5 – *Updated* long-term fundamental pricing projections (Exhibit SCW-2) now *inclusive* of an “Ultra High CO_2” sensitivity pricing scenario intended to approximate a theoretical Rockport Unit 1 “retrofit versus retire & replace” economic break-even.
- Exhibit SCW-6 – Summary of Rockport 1 unit disposition alternative analyses results over a shorter timeframe that would demonstrate the significant optionality afforded by retrofitting the unit with SCR technology *prior to* the possible future installation of a dry scrubber in 2025 (or 2028).

Q. WERE THESE EXHIBITS PREPARED OR ASSEMBLED BY YOU OR UNDER YOUR DIRECTION OR SUPERVISION?

A. Yes they were. As I will describe in this testimony, other functional organizations within I&M and AEPSC were involved in this evaluation process. The role I served was one of coordinating the attendant economic modeling effort and, ultimately, validating, documenting, and internally communicating this process and the results.

Q. PLEASE DESCRIBE THE CONTENTS OF EXHIBIT SCW-1.

A. Exhibit SCW-1 offers a broader overview of some of the other resource planning-related criteria that are necessarily introduced and considered as part of this evaluation of alternative options surrounding Rockport Unit 1 that will be discussed in this filing. The following direct testimony focuses more specifically on the discrete economic evaluations performed that led to the Company's conclusions and recommendations.

IV. ROCKPORT UNIT 1 DISPOSITION OPTIONS

Q. WHAT ARE THE NEARER-TERM ALTERNATIVES THAT ARE AVAILABLE TO I&M FOR PURPOSES OF REDUCING NO_X EMISSIONS AND ADDRESSING OTHER IMPENDING ENVIRONMENTAL REQUIREMENTS AT ROCKPORT UNIT 1?

A. As represented on the following **TABLE 1**, two alternative options—with one of those alternatives posing two sub-options—were modeled surrounding an I&M disposition decision associated with Rockport Unit 1:

TABLE 1

Option #1: Retrofit Rockport Unit 1 with SCR technology and associated equipment ("Rockport Unit 1SCR Project") by December 31, 2017 as well as, *for purposes of this I&M long-term economic evaluation process only…*

- retrofit Rockport Unit 2 with SCR technology for NO_X removal by December 31, 2019;

- add assumed ash pond, effluent waste-water treatment, and Clean Water Act-related equipment and investments at Rockport Plant by approximately 2019; and
- retrofit both Rockport units with "NID" Dry Flue Gas Desulfurization ("DFGD") technology by December 31, 2025 (Unit 1), and December 31, 2028 (Unit 2).

Option #2A (Shorter-Term PJM Purchases)**: Retire Rockport Unit 1 by December 31, 2017, and Replace it with some combination of similar-sized, new-build Natural Gas Combined Cycle ("CC") unit; Natural Gas Simple-Cycle Combustion Turbine ("CT") units; Dual-Fueled Internal Combustion ("IC") engines; as well as incremental demand–side management ("DSM") and new renewable (*i.e.*, wind and solar) resources by approximately <u>January 1, 2019</u>**, relying upon capacity and energy purchases from the PJM market to meet any deficiencies in the interim period.

Option #2B (Longer-Term PJM Purchases)**:** *same as Option #2A, except assume* **any replacement new-build CC, CT and/or IC resources by approximately <u>January 1, 2026</u>.**

Q. WHAT IS THE SIGNIFICANCE OF THE "DECEMBER 31, 2017" ROCKPORT 1 UNIT DISPOSITION DATE IDENTIFIED UNDER THESE MODELED OPTIONS?

A. December 31, 2017, represents the retrofit requirement date for the Rockport Unit 1 SCR as set forth within the terms of the Third Joint Modification to the Consent Decree ("Modified Consent Decree"). The Modified Consent Decree, and other existing and potential future environmental regulations, are discussed in detail in the testimony of Company witness Hendricks.

Q. UNDER "OPTION #1" YOU INDICATE THE LONG-TERM EVALUATION PROCESS UNDERTAKEN HAS ASSUMED THE *FUTURE* RETROFIT OF

DFGD TECHNOLOGY ON ROCKPORT UNIT 1, AS WELL AS SCR AND DFGD TECHNOLOGY ON ROCKPORT UNIT 2 BY: DECEMBER 2019 (FOR UNIT 2 SCR) AND NEXT DECADE (FOR UNITS 1 & 2 DFGD); AS WELL AS ADDITIONAL FUTURE INVESTMENT AROUND "ASH POND, EFFLUENT WASTE-WATER TREATMENT, AND OTHER CLEAN WATER ACT-RELATED EQUIPMENT". DOES THIS REPRESENT A PLANNED COMMITMENT ON THE PART OF I&M TO SUCH ADDITIONAL ROCKPORT INVESTMENT BEYOND THE ROCKPORT UNIT 1 SCR PROJECT?

A. No it does not. It simply offers—for current long-term modeling purposes only—a *potential* unit disposition line-of-sight. Under no circumstance does this option constitute a formal plan or recommendation by the Company for either Rockport unit beyond the nearer-term, Rockport Unit 1 SCR Project. Rather, it merely identifies the "down-stream" retrofit requirements/terms of the Modified Consent Decree as well as additional U.S. EPA requirements under the National Pollution Discharge Elimination System ("NPDES") permit program; the emerging Coal Combustion Residuals ("CCR") and Effluent Limitations Guidelines ("ELG") rulemaking; as well as anticipated modifications to the Clean Water Act 316(b) ("316(b)"); each described by Company witness Hendricks.

Q. RECOGNIZING THESE OUT-YEAR RETROFITS WERE FOR MODELING PURPOSES ONLY, WOULD SUCH A "STAGED" ROCKPORT UNIT 1 (AND UNIT 2) RETROFIT PLAN REPRESENT A REASONABLE APPROACH EVEN IF IT WERE DETERMINED IN THE FUTURE THAT

THE INSTALLATION OF A ROCKPORT UNIT 1 DFGD RETROFIT DID NOT REPRESENT AN APPROPRIATE ROCKPORT 1 UNIT DISPOSITION PATH FOR I&M AND ITS CUSTOMERS?

A. Yes. The modeled cost-recovery period for the relatively lower (versus the down-stream costs of the Rockport Unit 1 DFGD) capital cost Rockport Unit 1 SCR Project to be completed in December 2017 was assumed to be 10 years (*i.e.*, by end-of-2027). This period is consistent with the 10-year depreciation period which Company witness Williamson proposes the Commission approve for accounting and ratemaking purposes. However, a sensitivity analysis was also performed that would effectively proxy the costs associated with "full" recovery of this (SCR-related) retrofit investment by the end-of-20<u>25</u> for Unit 1 (approximately 8-year recovery). This permits us to fully understand the implications of the subsequent Rockport Unit 1 *DFGD* disposition option later next decade. In short, on a cumulative present worth basis, there was only a very minor difference in the life-cycle costs of the 2017 Rockport Unit 1 SCR Project if all such investment costs were recovered over the slightly shorter 8-year (versus 10-year) period. In fact, analogous to the typical favorable overall economics of a 15-year versus 30-year home mortgage, the full life-cycle economics of the Rockport Unit 1 SCR Project (Option #1)—to be detailed later in this testimony—would be slightly *improved* by $22 million if recovered over such shorter timeframes. Therefore, any such potential for "accelerated" Unit 1 SCR retrofit cost recovery recognition would not have any significant impact on the "base" long-term modeled option results to be discussed.

To reiterate, the modeling approach taken here was to offer a validation of <u>only</u> the nearer-term "Rockport Unit 1 SCR Project" disposition option. However, by virtue of capturing the current cost and performance parameter estimates associated with *all future* potential retrofit investments for Rockport Unit 1 (and, holistically, all future potential retrofit investments for Rockport Unit 2) as described in TABLE 1-Option #1; the Company contends it is setting forth a "full picture"—from a long-term economic perspective—of a potential *operate Rockport Plant* disposition plan. It would be anticipated that this modeling exercise would be formally repeated at some point prior to I&M's commitment to launch into the next phase of this long-term disposition (retrofit) plan for the Rockport Unit 2 SCR.

Q. ADDITIONALLY, THE OPTIONS IDENTIFIED IN TABLE 1 SUGGEST THAT ROCKPORT UNIT 1 WOULD BE THE EARLIER OF THE UNIT RETROFITS FOR DFGD TECHNOLOGY IN THE NEXT DECADE. IS THAT NECESSARILY THE CASE?

A. No it is not. In fact, the Modified Consent Decree simply identifies that one Rockport unit would "Retrofit, Retire, Re-power or Refuel" by December 31, 2025; and the other by December 31, 2028. It is not specific as to the ultimate unit order. Again, merely for purposes of this modeling exercise it was assumed that Unit 1 would be retrofitted with DFGD by the earlier date. It does not represent a commitment on the part of the Company.

Q. AS IT PERTAINS TO THE 2025 (AND 2028) DFGD RETROFIT ALTERNATIVE CITED IN THE MODIFIED CONSENT DECREE, WHY

WERE, FOR INSTANCE, THE (COAL-TO-GAS) "REFUEL" AND "(CC) REPOWER" OPTIONS NOT MODELED AS OUT-YEAR ALTERNATIVES?

A. These options were not modeled as out-year alternatives largely due to the fact that, as briefly addressed in the testimony of Company witness Walton , it is the Company's position at this point that the future retrofitting of the Rockport units with DFGD would be a more reasonable and economically-viable option—based on currently available cost estimates as well as engineering and design factors—versus either re-fueling either of these steam units to burn natural gas, or undertaking a major repowering of the units as natural gas CC facilities. That said, any formal assessment of Rockport disposition options to be performed in the future could more fully examine those additional alternatives.

Q. FOR PURPOSES OF THE ECONOMIC MODELING PERFORMED TO EVALUATE THE ROCKPORT 1 UNIT DISPOSITION OPTIONS, WHAT ARE SOME OF THE OTHER IMPLIED ASSUMPTIONS FOR I&M'S GENERATING FLEET?

A. The following "base" assumptions were utilized for I&M's Rockport Unit 2, Tanners Creek, D.C. Cook nuclear, as well as hydro and wind units in <u>each</u> of the alternative options applicable to the Rockport Unit 1 disposition analyses listed in TABLE 1:

- As previously summarized, Rockport Unit 2 was assumed to be retrofitted with SCR by December 31, 2019 and DFGD technology by December 31, 2028.

- Tanners Creek Units 1-4 were assumed to be retired by June 1, 2015 commensurate with EPA's Mercury and Air Toxics Standards ("MATS") Rule requirements.[1]
- Continued operation of D.C. Cook Units 1 and 2 through at least the mid-to-late 2030's.[2]
- Continued operation of all pre-existing hydro and wind resources; the latter including a new 200 megawatt (MW) wind purchase agreement effective in 2015.

Again, this in no way serves as a commitment to this course of action for, particularly, the installation of Rockport Unit 2 environmental control equipment. Such commitments and requests for consideration and approval surrounding such future disposition options for Rockport Unit 2 will be offered under a separate application. Rather, it simply serves as a going-in basis for the long-term modeling process for the "holistic" I&M resource optimization/disposition analysis I will describe in this testimony.

Likewise, for purposes of these evaluations, it was assumed that the respective I&M and affiliate AEP Generating Company ("AEG") 50 percent operating-leased shares of Rockport Unit 2 would continue beyond the current 2022 lease term date. As with the other implied assumptions, the future lease disposition of Rockport Unit 2 is one that is completely independent of the nearer-term decision around the installation of the Rockport Unit 1 SCR Project by December 31, 2017.

[1] Although the MATS Rule implementation date is April 16, 2015, it is expected that the AEP-East units being planned for retirement, including Tanners Creek 1-4, will be able to operate through the full PJM 2014/15 capacity "planning year" (*i.e.*, through May 31, 2015), after consultations with PJM working with several state environmental agencies responsible for overseeing the implementation of the MATS Rule.

[2] In-keeping with the units' 20-year Operating License Renewal to 2034 (Unit 1) and 2037 (Unit 2).

V. CAPACITY NEED

Q. DOES I&M HAVE A CAPACITY NEED THAT WOULD BE INFLUENCED BY THIS ROCKPORT UNIT 1 DISPOSITION DECISION?

A. Yes. First, as explained in greater detail in Exhibit SCW-1, I&M has an obligation to maintain a *minimum* PJM Installed Reserve Margin ("IRM") of 15.7 percent.[3] This IRM represents an obligation under PJM's capacity market construct—known as the Reliability Pricing Model ("RPM")—to ensure adequate future capacity resources are available to cover the Company's projected summer peak demand, as well as a reserve margin, needed to reasonably ensure reliability in the event of unforeseen supply interruptions and/or high peak demand events. As summarized on Exhibit SCW-1, Table 1-4, *inclusive* of Rockport Unit 1, the I&M projected IRM for the next PJM RPM planning year, 2018/19,[4] is estimated at 19.65 percent. This IRM level would result in a capacity "length"—*i.e.*, capacity levels above the minimum 15.7 percent PJM criterion—of a relatively modest 156 MW.

Therefore, any unit disposition decision that would implement an alternative of retiring I&M's 1,118 MW ownership and purchase entitlement share of Rockport Unit 1[5] would result in an immediate and significant need to replace nearly all of that capacity to ensure achieving this PJM IRM criterion. This explains why the "Option 2" alternatives previously identified in TABLE 1

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[3] Beginning with the established 2015/16 (June 1 through May 31) PJM RPM delivery year; and assumed to remain constant in all future RPM planning years.

[4] As also discussed in Exhibit SCW-1, I&M (as well as affiliates Appalachian Power Company and Kentucky Power Company) have continued to opt-out of the RPM "capacity auction" process by participating in the Fixed Resource Requirement ("FRR") "self-planning" construct afforded under the RPM. Under the RPM framework that establishes a 3-year forward commitment, this FRR obligation has now been established for the 2017/18 RPM planning year.

[5] 657.5 MW (50%) ownership share of the 1315-MW unit; plus I&M's 460.2 MW (70%) purchase entitlement from affiliate AEG's 50% ownership share of the unit.

called for a near-immediate replacement of the unit with either "new-build" capacity (Option 2A); or significant purchases of capacity from the RPM market for some period (Option 2B).

VI. ECONOMIC MODELING PROCESS

Q. HOW WERE THE ROCKPORT UNIT 1 DISPOSITION ALTERNATIVES ANALYZED?

A. The Company utilized a proprietary long-term resource optimization tool known as PLEXOS® (also referred to as "PLEXOS® LT Plan") to perform this evaluation. The economic evaluations were performed from the perspective of a "stand-alone" I&M. This means there were no assumed capacity and energy costs or credits flowing to/from affiliate AEP operating companies by virtue of the fact that the long-standing AEP Interconnection Agreement ("AEP Pool")—as discussed in Exhibit SCW-1—has now been terminated and replaced with the FERC-authorized Power Coordination Agreement ("PCA") effective January 1, 2014. Under the terms of the PCA, I&M, as well as the other AEP-affiliate operating company participants in the PCA, "…will be individually responsible for its own capacity planning."[6]

Further, these resource optimization evaluations were performed over an extended (27-year) modeled period (2014 through 2040) in the PLEXOS® tool so as to roughly emulate the potential economic life-cycle of the respective asset alternatives offered in TABLE 1; as well as in recognition of the various future impacts on I&M's overall resource planning needs. As will

[6] Article 7.1 of the Power Coordination Agreement (FERC Docket No. ER13-235-000, approved on December 23, 2013).

be described in more detail, the alternative-specific 'Net Utility Costs' were then discounted to current, "2014" dollars and, as such, reflected on a cumulative present worth ("CPW") basis. It is also critical to understand that the framework for these evaluations was focused not on the *absolute* CPW results for I&M, but rather the *comparative* view of the alternative options' results. In other words, the objective of this exercise was to identify the relative least-cost alternative among the three primary options identified in TABLE 1. Finally, the results from PLEXOS® offer a view of these relative optimization economics over that full, nearly 30-year planning horizon and thereby do not constitute an isolated, single "test-year" cost-of-service view.

Q. PLEASE DESCRIBE THE PLEXOS® LONG-TERM MODELING APPLICATION.

A. PLEXOS® is a proprietary software tool under license to AEPSC from Energy Exemplar LLC, a power and gas industry software and data-services provider. As indicated, the PLEXOS® LT Plan version of the application is a long-term resource optimization model that offers multiple objective functions, including determination of alternative planning solutions that offer the lowest utility cost. In this case, it is intended to determine a proxy for the lowest "G(eneration)" (net) cost-of-service.[7] The model uses linear programing ("LP") optimization techniques to find the optimal portfolio of future capacity and energy resources, including demand-side additions, that serve to minimize the CPW of a planning entity's production-related fixed and variable costs over a long-

[7] It is important to re-emphasize that PLEXOS® does not produce, nor are these (relative) long-term modeling results intended to represent, a traditional "cost-of-service" view; recognizing that the latter process focuses on a single—versus 'comparative'—view of costs and is also limited to a single 'test-year'—as opposed to a 25-30 year proforma—view.

term planning horizon. The model performs this optimization while also recognizing user-input constraints such as requisite PJM reserve margin requirements, as well as I&M fleet-wide or unit-specific stack emission (e.g. SO_2 and NO_X) limitations.

This latter ability is important given that the Modified Consent Decree also places a Rockport (total) station-specific "cap" on SO_2 emissions of 28,000 tons per year in 2016-2017; 26,000 tons per year in 2018-2019; 22,000 tons per year in 2020-2025; 18,000 tons per year in 2026-2028; and 10,000 tons per year in 2029 and thereafter.[8] These station-specific SO_2 requirements are over-and-above the pre-existing AEP performance thresholds around SO_2 and NO_X emissions as set forth in the original NSR Consent Decree. The retrofit of SCR on Rockport Unit 1 will contribute to the attainment of the latter requirement.

Q. HAS THE PLEXOS® APPLICATION BEEN UTILIZED BY THE COMPANY IN MATTERS BEFORE THIS COMMISSION?

A. Yes. PLEXOS® was utilized as the applicable modeling tool in I&M's most recent Integrated Resource Plan ("IRP") submitted on November 1, 2013. Specifically, it served as the basis for the establishment of the resource planning included under Section 8-"Selection of the Resource Plan"—as required under 170 IAC 4-7-8.[9] Additionally, PLEXOS® was utilized as part of the Company's three most recent biannual Fuel Adjustment Clause ("FAC")

[8] The last threshold year (2029) representing the first year in which <u>both</u> Rockport units would be potentially retrofitted with DFGD technology under the Modified Consent Decree.

[9] *See* Section 8 of that submittal for a description of how PLEXOS® LT Plan was utilized in I&M's 2013 IRP.

filings.[10] It was also utilized as part of I&M's two most recent Environmental Compliance Cost Rider ("ECCR") filings.[11] Likewise, PLEXOS® was utilized to establish I&M's most recent Power Supply Cost Recovery plan for its Michigan retail jurisdiction.[12] Further, PLEXOS® has recently been utilized by other AEP operating companies to support both long-term resource planning options as well as shorter-term fuel factor applications before Commissions in the states of Kentucky, Oklahoma, Virginia, and West Virginia.

Q. YOUR TESTIMONY DESCRIBES THAT THE PLEXOS® (LT PLAN) MODELING CREATES A PROXY FOR LONG-TERM NET UTILITY "G(ENERATION)" COSTS. WHAT ARE THE FUNDAMENTAL MODELING PROCESSES AND OUTPUTS THAT CREATE THESE RESULTS?

A. First, the PLEXOS® model seeks to emulate the PJM energy construct in which all available generation is offered into, and is compensated by, the PJM energy market; while all Load Serving Entities, such as I&M, are price-takers from that market. Both of these time-based value-sets are predicated on the future, fundamentals-based price of energy which will be described later in this testimony. As a vertically-integrated utility, the subsequent 'netting' of those (PJM) "(Generation) Market Revenues" and "Load Costs" profiles are then appended to the anticipated production cost of I&M's native generation, to create a picture of I&M's projected future net utility (generation) costs. The model determines such generation-related costs as follows:

Cost of Generation…

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[10] *See* IURC Cause Nos. 38702-FAC70, 38702-FAC71 and 38702-FAC72.
[11] *See* IURC Cause Nos. 43992-ECCR 2 and 43992-ECCR 3.
[12] *See* MPSC Case No. U-17318

Variable Costs associated with I&M generating units' ability to offer into, and ultimately dispatch into the (PJM) energy market. Such attendant variable costs including:

- Fuel;
- Start-up oil;
- Consumables such as sodium bicarbonate, activated carbon, anhydrous ammonia, and lime;
- Variable O&M; and
- Market replacement cost of emission allowances and/or carbon 'tax'

Plus: Variable Costs of Energy Purchases

Plus: Fixed Costs of Capital Additions *; *i.e*, Investment Carrying Charges (based on I&M's weighted cost of capital)

Plus: Fixed O&M of Capacity Additions

Plus: Fixed Cost of Capacity Purchases

Plus: Program Costs of (Incremental) Demand-Side Management (DSM) options

= **Total Generation Costs**

* Note: Any on-going 'return-on' and 'return-of' (depreciation/amortization) capital costs associated with pre-existing generation plant-in-service and other balance sheet assets/obligations are ignored, as such attendant costs would be assumed to be *consistent across all unit disposition options evaluated*.

To further summarize, the model simultaneously determines the energy-related "Cost of Load" based on assumed PJM "scaled" (e.g. on-peak and off-peak) market energy prices applied to I&M's forecasted native load obligation—and underlying load shape. The model output then performs a concurrent "netting" of: a) I&M's Load cost; and b) the production *revenue* made into the forecasted (PJM) energy market from the *generation* shape profiles modeled for each I&M generation resource. When then further coupled with the "Cost of Generation" previously defined, the ultimate 'net' output represents a proxy for I&M's net load/production-related generation costs. The final component output from the modeling process would be the monetization of any I&M capacity length (long *or* short) position—vis-a-vis PJM's minimum reserve margin requirements—based on projected PJM capacity market values. The *final* result is the establishment of I&M's "Net Utility (Generation) Costs" summarized as follows:

(PJM) Load Cost
Plus: Total Generation Costs *(as above)*
Less: (PJM) Energy Market Revenue
= Net Load/Production-related Generation Costs
Less: (PJM) Capacity Market Revenue/<Cost>
= **Net Utility (Generation) Costs**

These life cycle costs through the 2040 modeled optimization period, along with applicable end-effects[13], are then "present-valued" using a proxy of the estimated I&M-weighted average cost of capital, to create a CPW of Net Utility (Generation) Costs.

Q. SPECIFICALLY, HOW DID THE PLEXOS® MODEL PERFORM THE ROCKPORT UNIT 1 DISPOSITION ANALYSES PREVIOUSLY SUMMARIZED ON TABLE 1?

A. For "Option #1", the model incorporated the initial Rockport Unit 1 SCR Project alternative—and timing thereof—as described earlier in TABLE 1. Specifically, Rockport 1 was assumed to be retrofitted first with DSI and associated equipment (for MATS compliance) by April 16, 2015, then SCR technology by December 31, 2017; and finally with subsequent anticipated environmental-related retrofits thereafter—including DFGD technology by December 31, 2025. The remaining I&M generating units were assumed to follow the "base" disposition path assumptions previously discussed.

[13] Recognizing the varying life cycle periods among alternatives evaluated, an "end-effects" determination was made that is representative of the present value of any on-going cost streams beyond the model's 2040 optimization period.

However, for both of the “Option #2” approaches (variations of a ‘retire and replace’ Rockport Unit 1 with [PJM] market capacity and energy, followed by the construction of new-build capacity), the only thing that the model specifically incorporated was the in-service *timing* of the assumed Rockport Unit 1 replacement new-builds—January 1, 2019, for “Option #2A”; and January 1, 2025 for “Option #2B”. For both of these alternative sub-options the model was given the ability to select the specific type of capacity resource required to replace Rockport Unit 1 by way of the model’s resource optimization logic. In that regard, given the assumption of the impracticality of a coal solution due to proposed New Source Performance Standards (“NSPS”) for greenhouse gases applicable to new fossil-fired capacity, a new coal-fired generating build was not considered. Likewise, given the financial impracticability of new nuclear capacity, a new nuclear unit was also not considered. With that, the model had the ability to choose between some combination of natural-gas fired CC, CTs, IC engines, as well as *incremental* DSM and renewable resources.[14]

From there, the model was set up with the necessary input parameters, such as capital cost to retrofit or to replace with alternative resources, the attendant fuel cost and generator performance parameter data, modifications to variable and fixed O&M, etc. Based on these inputs, beginning in the year 2018—the initial full year of Rockport 1 being retrofitted with SCR—the model was then capable of recognizing any relative change in

[14] Specifically, additional DSM over-and-above the levels embedded in the Company’s load & peak demand forecast (as summarized on Exhibit SCW-1, Table 1-3); as well as additional renewable resources over-and-above those currently identified (or footnoted) on Exhibit SCW-1, Table 1-4.

the overall I&M generation profile for each of the three Rockport Unit 1 disposition options identified in TABLE 1. Additionally, the capacity resource planning aspect of the tool recognized the megawatt contribution of these alternative solutions when determining capacity needs for I&M *beyond* 2018 as it modeled throughout the long-term optimization planning horizon (*i.e.*, through 2040).

Q. COULD YOU PLEASE IDENTIFY SOME OF THE MORE CRITICAL INPUT PARAMETERS FOR THESE ROCKPORT UNIT 1 DISPOSITION ANALYSES AND WHERE THAT INFORMATION WAS SOURCED?

A. Two of the major underpinnings in this process are long-term forecasts of I&M's energy requirements and peak demand, as well as the price of various generation-related commodities, including energy, capacity, coal, natural gas, and CO_2/carbon. Both forecasts were created internally within AEPSC. The load forecast, including the I&M load and demand summaries discussed in Exhibit SCW-1, represents the most recent projection created by the AEP Economic Forecasting organization. Exhibit SCW-2 offers the most recent long-term commodity pricing forecast created by the AEP Fundamental Analysis group. These respective organizations have had years of experience forecasting I&M and AEP system-wide demand/energy requirements and fundamental pricing for both internal operational and regulatory purposes.

Other critical input parameters include the installed cost of the required Rockport Unit 1 SCR Project, the cost to build/buy replacement capacity (e.g. CC, CTs, IC engines, or incremental DSM and renewable resources [wind, solar]), as well as the attendant on-going operating costs and performance parameters associated with those unique options, where applicable. This information is summarized on Exhibit SCW-3. The critical build-cost data was largely sourced from Company witness Walton and the AEP Generation organization of which he is a part.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF OPTION #2 (RETIRE AND REPLACE WITH CC, CT AND/OR IC).

A. The PLEXOS® modeling required to reasonably proxy this option as it pertains to the installation of a baseload/intermediate duty-cycle capability was based on a Mitsubishi 501 GAC 2x2x1 combustion turbine/heat recovery steam generator (HRSG)/steam turbine design[15] natural gas CC that would have a nominal capability of approximately 780 MWn[16]. As an input process to the PLEXOS® modeling, this type of CC was screened as being the 'best-in-class' from multiple potential CC designs. The chosen proxies for potential peaking duty-cycle capability were based on both a simple-cycle General Electric '7EA' natural gas CTs that would have a nominal capability of approximately 164 MWn[17] *as well as* a "series" of modular, Wartsila 20V34SG IC engines having a nominal capability of approximately 201 MWn.[18] The GE SC-CTs and the Wartsila IC engines were likewise screened as the best-in-class from multiple potential "peaking" duty-cycle resource options.

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[15] This represents two natural gas combustion turbines in combination with two HRSGs and a single steam turbine.

[16] This Mitsubishi design CC would provide additional duct-firing capability that could periodically increase the unit's maximum seasonal capability—albeit at a thermal efficiency/heat rate penalty—to 906 MW.

[17] Each GE 7EA turbine is nominally rated @ 82 nominal megawatts ("MWn"). A minimum GE 7EA SC tranche size was assumed to be a 2-turbine option; or ~164 MWn.

[18] Each Wartsila 20V34SG dual-fueled IC engine is nominally rate @ approximately 9 MWn, with a (screened) installed tranche size of 22 engines; or ~201 MWn .

Q. WHAT ESTIMATED COSTS FOR OPTION #1 (RETROFIT) AND OPTION #2 (RETIRE AND REPLACE WITH SOME COMBINATION OF CC, SC-CT, IC) WERE UTILIZED IN YOUR DETAILED ECONOMIC EVALUATIONS?

A. The following **TABLE 2** offers a summary of the installed cost estimates modeled:

TABLE 2

Estimated Rockport Unit 1 Disposition Alternative
Major Capital Expenditures (excl. AFUDC)
Utilized in Plexos® Modeling
In Addition to Increm. DSM, Wind, Solar

Line	Description	Unit Capacity MW		(a) Direct (EPC) & Indirect Costs: Millions ('As-Spent' $)	(b) Direct (EPC) & Indirect Costs: $/kW Installed (2013 $)	(c) I&M/AEG Prod. Capital Overhead: Millions ('As-Spent' $)	(d) TOTAL COST (Excluding AFUDC): Millions ('As-Spent' $)	(e) TOTAL COST (Excluding AFUDC): $/kW Installed (2013 $)
(1)		*Unit Capacity*		Millions	$/kW Installed	Millions	Millions	$/kW Installed
(2)		*MW*		*('As-Spent' $)*	*(2013 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2013 $)*
(3)	**Option #1:**							
(4)	**(Unit 1 RETROFIT Option)**							
(5)	TOTAL Project Costs							
(6)	**Rockport U1 SCR (12/2017 in-Svc)**	*1,351*	(A)	**$216**	**145**	**$19**	**$235**	**158**
(7)	*Plus: Potential Subsequent Major U1 & U2 Investments included in Modeling:*							
(8)	*RK U2 SCR (12/2019 in-Svc)*	*1,336*	(A)	*$226*	*142*	*$20*	*$246*	*155*
(9)	*RK U1 DFGD & Assoc. (12/2025 in-Svc)*	*1,333*	(B)	*$1,398*	*715*	*$123*	*$1,521*	*778*
(10)	*RK U2 DFGD & Assoc. (12/2028 in-Svc)*	*1,318*	(B)	*$1,551*	*724*	*$137*	*$1,688*	*788*
(11)	*RK U1 & U2 "NPDES/CCR/ELG" & "316(b)"-related,*							
(12)	*Total Plant (thru 2019)*	*2,687*	(A)	*$155*	*49*	*$14*	*$169*	*53*
(13)	*TOTAL ALL Major Rockport Environmental Projects (U1&.*	*2,579*	(B)	*$3,546*	*915*	*$313*	*$3,859*	*995*
(14)	I&M Ownership Share @ 50%							
(15)	**Rockport U1 SCR (12/2017 in-Svc)**	*676*		**$108**	**145**	**$10**	**$118**	**158**
(16)	I&M 70% Purchased Power Portion *of AEG's 50% Ownership Share* (C)							
(17)	**Rockport U1 SCR (12/2017 in-Svc)**	*473*		**$76**	**145**	**$7**	**$82**	**158**
(18)		*Unit Capacity*		Millions	$/kW Installed	Millions	Millions	$/kW Installed
(19)		*MW*		*('As-Spent' $)*	*(2013 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2013 $)*
(20)	**Option #2:**							
(21)	**(Unit 1 CAPACITY REPLACEMENT Options)** (D)							
(22)	**New-Build CC...** 12/2018 In-Svc (**Option #2A**)	*906*	(E)	$1,029	997	$113	$1,142	1,106
(23)	" " " ... 12/2024 In-Svc (**Option #2B**)	"		$1,265	997	$139	$1,404	1,106
(24)	*AND (IN COMBINATION WITH) / OR ...*							
(25)	**(2) x New-Build CT...** 12/2018 In-Svc (**Option #2A**)	*2x82 = 164 per block*		$152	788	$17	$168	875
(26)	" " " " ... 12/2024 In-Svc (**Option #2B**)	"		$186	788	$21	$207	875
(27)	*OR*							
(28)	**(22) x New-Bld IC Engine...** 12/2018 In-Svc (**Option #2A**)	*22x9 = 201 per block*		$250	1,055	$28	$278	1,171
(29)	" " " " " ... 12/2024 In-Svc (**Option #2B**)	"		$307	1,055	$34	$341	1,171

(A) Rockport U1 & U2 capacity rating post-planned LP Turbine (36 MW each) uprates (2017 & 2019)
(B) Rockport U1 & U2 capacity rating post-DFGD retrofits (<18 MW> each) derates (2025 & 2028)
(C) I&M would ALSO incur its 70% share of fixed costs associated with AEG's like-50% share of the project (or, 35% of the 'Total Project')
under the terms of the affiilate AEP Generating Company (AEG) Unit Power Agreement with I&M.
(D) AEP Projects cost estimates used for modeling purposes.
(E) Includes 126-MW additional capacity (vs. nominal rating) associated with duct-firing capability

I would like to point out the 50 percent ($118 million) I&M ownership share of the capital expenditure associated with the Option #1 "Rockport Unit 1 SCR Project" solution. I&M-affiliate AEG would be responsible for the other

50 percent share of the required capital expenditure. In recognition of this, however, these I&M-Rockport Unit 1 disposition analyses *also* considered 70 percent of the costs of the AEG ownership portion of this retrofit solution by virtue of I&M's obligation under the AEG unit power agreement. Stated another way, the Option #1 analysis effectively reflected 85 percent (1,118 MW) of the capacity (and energy) output, as well as attendant costs, associated with the approximate 1,315 MW Rockport Unit 1.[19]

Note also that these costs are exclusive of allowance for funds used during construction ("AFUDC"). As it pertains to the Option #1 Rockport Unit 1 SCR Project estimate, the total project cost inclusive of production capital overheads as well as AFUDC was modeled at approximately $261 million (with I&M's 50% ownership share being nearly $132 million). Conservatively, this calculated AFUDC proxy of nearly $26 million (I&M's ownership share being approximately $14 million) was incorporated for comparative modeling purposes only and is, obviously, before consideration of any potential construction work in progress ("CWIP") recovery treatment as discussed in Company witness Williamson's testimony that would serve to eliminate all or a portion of any such project-related AFUDC.[20]

Q. EARLIER YOU DISCUSSED "DOWN-STREAM" COSTS ASSOCIATED WITH ENVIRONMENTAL INVESTMENTS BEYOND THE CURRENT "ROCKPORT UNIT 1 SCR PROJECT". PLEASE BRIEFLY DESCRIBE

[19] Represents I&M's 50% ownership share, plus, 70% of AEG's 50% ownership share, or 85%.
[20] $261 million total (100%) project cost - $235 million total cost (including production capital overhead, but excluding AFUDC – see TABLE 2)

SUCH OPTION #1 TOTAL UNIT 1 COST PROJECTIONS INCORPORATED INTO YOUR MODELING THAT ARE ALSO SUMMARIZED ON TABLE 2.

A. As summarized on TABLE 2, the PLEXOS® modeling for Option #1 incorporated approximately $1,437 million of additional estimated I&M capital costs for various future Rockport Unit 1 projects beyond this SCR Project. Specifically, this figure represents I&M's 85 percent ownership *and* (AEG) purchased power share of the combined investment in future Unit 1 DFGD and associated equipment (total $1,521 million), and "NPDES/CCR/ELG" and "316(b)"-related ($169 million, total plant) capital costs identified on TABLE 2.[21]

Q. COULD YOU OFFER AN OVERVIEW OF THE "NEARER-TERM" RESOURCE COMPONENTS ASSOCIATED WITH OPTION #2, WHICH CALLS FOR I&M TO RELY ON PURCHASES OF CAPACITY (AND ENERGY) FROM A PJM MARKET, IN LIEU OF PERFORMING THE ROCKPORT UNIT 1 SCR PROJECT (OR FUTURE RETROFITS)?

A. The PLEXOS® modeling for Options #2A and #2B was based on the assumption that any and all incremental capacity and energy requirements to match up against I&M native peak demand and load requirements, in recognition of a Rockport Unit 1 retirement by December 31, 2017, would largely be met via PJM-market sourcing. Further, it was assumed for modeling purposes that CC, CT, and/or IC engine replacement capacity and energy would then ultimately be introduced into I&M's generation portfolio by either January 2019 (Option #2A), or January 2025 (Option #2B).

[21] ($1,521 million + $169 million) x 85% = $1,437 million (including capital overheads, excluding AFUDC).

For incremental PJM-market *capacity* valuation, this nearer-term market replacement option further assumed, as a proxy, the utilization of internal estimates for market values for the PJM RPM Unforced Capacity ("UCAP") provided by the AEP Fundamental Analysis group.

Similarly, the attendant I&M incremental nearer-term PJM-market *energy* requirements that would emerge under these Option #2 Rockport Unit 1 'retire and replace' alternatives were determined in PLEXOS® utilizing AEP Fundamental Analysis' estimates of PJM on-peak and off-peak energy pricing proxied at the AEP generating (market) hub.

Exhibit SCW-2 includes a summary of these respective capacity and energy long-term forecast values.

Q. WHAT MIGHT THE CONCERNS BE IF I&M WERE TO EXERCISE AN ALTERNATIVE, SUCH AS OPTION #2, THAT WOULD FOREGO AN "ASSET" SOLUTION WITH ONE THAT WOULD INITIALLY BE LARGELY DEPENDENT ON PROJECTED PJM (RPM) CAPACITY AND ENERGY MARKET PRICING FOR APPROXIMATELY 1,100 MW OF GENERATION BASELOAD CAPACITY, FOR A PERIOD AS LONG AS 8 YEARS (OPTION #2B)?

A. Such an approach would potentially subject I&M and its customers to additional cost and performance risks. As summarized in my Exhibit SCW-1 information appendix, AEP and I&M have continued to elect to "opt-out" of the PJM-RPM capacity market (auction) construct under the notion that "…the interests of its customers are better preserved under that FRR framework."[22] This statement implies that I&M views the obligation to reliably serve its customers as paramount. The Company has no assurances that future capacity required by PJM to ensure region reliability will be built as a result of the PJM-RPM construct. In fact, according to PJM's own 2016/2017 RPM Base Residual Auction Results report, since the RPM's inception for the 2007/08 planning period, and through the 2016/17 3-year forward planning period, only 19,145 MW of *new* thermal installed capacity ("ICAP") has been offered into all of those ten Base Residual Auctions combined[23], an annual average of only 1,915 MW for a capacity market with a load and reserve obligation of approximately 169,000 MW.[24]

Q. GIVEN THESE CONCERNS REGARDING THE FUTURE TIMELY AVAILABILITY OF CAPACITY UNDER THE PJM-RPM MARKET CONSTRUCT, WHAT IS YOUR CONCLUSION REGARDING OPTION #2 (RETIRE AND FULLY-REPLACE ROCKPORT UNIT 1—WITH PJM MARKET PURCHASES)?

A. The value of PJM-RTO[25] capacity forecasted by the AEP Fundamental Analysis group is, in most forecast years, well below the (fixed) cost of a new CC-build, as well as below PJM's established Net Cost of New Entry

[22] Exhibit SCW-1, page 6.
[23] http://pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx; Table 8, pg. 22
[24] Represented by UCAP that cleared the 2016/17 PJM-RPM Base Residual Auction.
[25] The projection of RPM capacity value offered by the AEP Fundamentals group reflects PJM's western-most or "RTO" region.

("CONE") value.[26] As a result, based on the modeling results and the above-stated concerns, I objectively conclude that any potential economic benefit of an initial "market" option (Option #2) could be quickly eliminated. Specifically, any perceived benefits of an Option #2 could be diminished upon recognition that:

a) the price of capacity under the PJM-RPM market currently clears on a *single* incremental planning year basis, with <u>no</u> assurances—for sellers or buyers—as to the *sustainability* of those prices from year-to-year;

b) from a buyer's perspective, the price of capacity under the PJM-RPM construct could begin to ultimately mirror, or exceed, Net CONE on a consistent basis[27]; and/or

c) even if RPM capacity prices were to remain somewhat below an equivalent "Net CONE" value/price threshold, I&M would effectively incur some level of reserve margin *penalty* due to the relative construct of the RPM[28], versus the "fixed" (15.7 percent) reserve margin obligation under the Company's currently-elected Fixed Resource Requirement (FRR) option.

Further, there were no modeled economic outcomes that would alter the Company's contention that—when coupled with the fact that PJM-RPM capacity market construct remains relatively immature—the inherent year-to-

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[26] CONE is an RPM-market proxy for a base/"1.0" multiple capacity value based on the fixed cost associated with the construction of a simple-cycle combustion turbine, *net* of some (typically small) market credits that would be subscribed to that CT via the sale of energy and other ancillary products.
[27] The current Net CONE value for RTO UCAP for the 2017/18 PJM-RPM forward planning year was established by PJM at $351.39 per MW-day.
[28] Based on the administratively-established Variable Resource Requirement ("VRR") demand curve utilized in the RPM construct, prior Base Residual Auction clearing prices for the RTO have resulted in "implied" Installed Reserve Margins above 20 percent.

year pricing uncertainty and economic risks around being a capacity market "price-taker" are not in the best interest of I&M's customers.

Q. COULD I&M EXERCISE YET OTHER MARKET OPTIONS TO REPLACE THE APPROXIMATE 1,100 MW OF ROCKPORT UNIT 1 CAPACITY AND ENERGY IT CURRENTLY OWNS OR HAS A PURCHASE ENTITLEMENT FROM AEG, IN LIEU OF A PJM-RPM MARKET OPTION?

A. Yes. Recognizing the termination of the previous AEP Pool and its capacity sharing/equalization features by and among its Member Companies—and recognizing the succeeding PCA does not provide for such affiliate capacity sharing going-forward—other options could theoretically be available to I&M. For instance, recognizing that I&M indeed has become a stand-alone entity from a planning perspective—in addition to a (Rockport Unit 1) retrofit or replacement/new-build approach—an option could be to enter into a market-based competitive solicitation for as much as ~1,100 MW of the Rockport Unit 1 capacity and attendant energy being contemplated for replacement.

Q. DID I&M ISSUE SUCH A FORMAL COMPETITIVE SOLICITATION?

A. No it did not.

Q. WAS A REQUEST FOR PROPOSAL (RFP) OPTION FOR AS MUCH AS 1,100 MW OF REPLACEMENT CAPACITY AND ENERGY CONSIDERED AND EVALUATED?

A. Yes. Such a market option/view *was* effectively considered. Option #2 (Retire and Replace Rockport Unit 1 with New-Build CC, CTs, IC engines and/or incremental DSM and renewables option by 1/2019 [Option #2A], or by 1/2025 [Option #2B]) offered such a bi-lateral market proxy. Based on discussions with AEP commercial experts, it is very reasonable to assume that a *long-term* (minimum, 10-20 year term) competitive purchase power agreement ("PPA") solicitation—for not only up to as much as 1,100 MW of replacement capacity, but for the largely baseload <u>energy</u> also being replaced—would likely be offered/priced at the cost of a new-build combined cycle in response to such an RFP, in any event, given the sheer size of the capacity and energy solicitation. Hence, the Company viewed the results of these Option #2 modeling views as being representative of what would have likely resulted from a formal RFP process.

Q. COULD OTHER, PREVIOUSLY-BUILT CAPACITY ALREADY RESIDING WITHIN THE PJM FOOTPRINT BE OFFERED AS PART OF ANY SUCH LONG-TERM, ~1,100 MW RFP UNDERTAKING BY I&M?

A. While that is possible, such existing asset markets are limited, particularly for higher-utilization CC assets. Also, essentially all of any potential "merchant" CC assets residing in PJM were built early last-decade (or earlier). Given this, there is an emerging concern that any such CC facilities could soon be facing significant, time-based turbine inspections and expensive re-builds as well as other steam-cycle and balance-of-plant maintenance issues; thereby lessening their relative economic values. Considering this (bi-lateral) market uncertainty surrounding existing CC generating assets, it further suggests that even if one were to assume that such generating capacity and energy *were* available, those prices—via an asset purchase, or PPA—would likely ultimately proxy the cost of new-build replacement CC capacity and energy, a model alternative under Option #2, *discounted* for known and measurable relative poorer efficiency and performance characteristics as well as incrementally-required, emerging life-cycle maintenance costs.

Further, and as will be addressed further later in this testimony, given the significant economic advantage of an “operate Rockport Unit 1” solution (Option #1) over the full life-cycle study period examined, a new-build ‘CC’ replacement alternative would require a “break-even” cost to construct of only $329 per kW (2013 dollars), under the ‘Base’ pricing scenario evaluated. Considering this, the Company objectively determined that any attempt to formally seek out any near-term market purchase of a CC—at an even lower, discounted ‘break-even’ price for an *existing facility*— would be pointless. Moreover, as will also be discussed in greater detail later in this testimony, the nearer-term optionality offered to I&M via the Rockport Unit 1 SCR Project, vis-à-vis any alternative that would retire the unit by December 2017, is significant. In other words, in that nearer-term—*i*.e., *through the period leading up to a potential DFGD retrofit in 2025*—the relative economic advantage of the Rockport Unit 1 SCR Project would be expected to be far superior when compared to the cost of any potential generating asset build or acquisition.

In sum, the relative low cost of the Unit 1 SCR retrofit ($158/kW, excluding AFUDC -- from ‘TABLE 2’) is far below the cost of, for instance, new CC replacement capacity ($1,106/kW, excluding AFUDC – from ‘TABLE 2’). Therefore, *even if* an existing combined cycle facility were available for purchase, the necessary discounting of the purchase price would have to be unfathomably immense in order to achieve economic unity versus the relative low capital cost Unit 1 SCR retrofit alternative over the period December 2017 through 2025; or over the full study period evaluated.

Q. IN DEVELOPING THE COMPANY'S FUTURE RESOURCE OPTIONS, DID THE COMPANY EVALUATE DEMAND-SIDE/ENERGY EFFICIENCY AND DEMAND RESPONSE RESOURCES IN DETERMINING THE LEAST-COST ALTERNATIVE TO MEET ITS LONG-TERM OBLIGATIONS IN LIEU OF ROCKPORT UNIT 1?

A. Yes. As described and detailed in Exhibit SCW-1, Section II, DSM in the form of Energy Efficiency (EE) and Demand Response (DR) initiatives have been incorporated into the Company's resource planning process as part its underlying load forecast. These forecasted levels of EE reductions incorporated into all of I&M's long-term resource modeling are significant. Note on Table 1-3 of Exhibit SCW-1, that the Company is projected to realize permanent peak demand reductions from EE alone of 194 MW over the balance of this decade. Additionally, incremental DR resources—above the 240 MW currently registered in PJM—are expected to add further peak demand capabilities of 56 MW. With that, the Company's *total* demand-side peak reduction capability is already projected to be 490 MW by 2020. This amount is equal to approximately 14.5 percent of I&M's forecasted retail peak demand.[29] Given the more limited ability of DSM to add large tranches of resources to I&M's overall portfolio, and recognizing the previously-projected EE mandates in Indiana, any <u>incremental</u> contribution, over-and-above what is already contemplated in the underlying load and peak demand forecast,

[29] Based on projected 2020 I&M (retail only) peak demand of 3,360 MW.

must be considered minimal in the context of the approximate 1,100 MW of I&M's Rockport Unit 1 capacity at issue.

That said, the PLEXOS® long-term resource optimization modeling did seek to consider such *incremental* contributions of EE resources as part of the evaluation process. The model was given the ability to select from eight (8) potential incremental DSM-EE measure "families" including: Residential Cooling; Residential Heating; Residential Lighting; Residential Other; Commercial Cooling; Commercial Heating; Commercial Other (largely lighting); and Industrial. I will discuss the result of that modeling later in this testimony.

However, it should be noted that achieving such incremental EE over-and-above those levels already implicit within the Company's long-term load forecast, described above, *without* the continued benefit of many efficient lighting measures—which have served to drive the results of utility-sponsored efficiency programs prior to the phase-out of the lighting standards in the Energy Independence and Security Act of 2007—is without precedent. For instance, a recent market potential study performed for the state of California has quantified a *maximum* achievable level of energy efficiency at approximately 0.6 percent per year for the remainder of this decade.[30] While Indiana and Michigan are not California, the study is instructive in its reduction of targets due in large part to the loss of many lighting measures as reasonable DSM resource options.

[30] "Analysis to Update Energy Efficiency Potential, Goals, and Targets for 2013 and Beyond"; Navigant Consulting, March 2012.

Similarly, I&M's projected 2020 total DR resources of 490 MW, or 14.5 percent of retail peak demand (3,360 MW), far exceeds the 8.9 percent reduction figure described as a "maximum achievable" level in the often-cited 2009 EPRI Market Potential Study.[31]

Q. YOU INDICATED PREVIOUSLY THAT EACH MODELED ALTERNATIVE HAS INCORPORATED AN ADDITIONAL 200 MW (NAMEPLATE) OF WIND RESOURCES BY 2015 PURSUANT TO A RECENT WIND RESOURCE PURCHASE AGREEMENT. PLEASE DESCRIBE THAT TRANSACTION?

A. On February 25, 2013, the Company issued an RFP for up to 200 MW of nameplate-rated wind energy resources to be in-service by December 31, 2014. The Company reviewed the results of that solicitation and negotiated a 200 MW, 20-year renewable energy purchase agreement ("REPA") with one of the offering parties, effective December 2014. The Commission subsequently approved the REPA between I&M and Headwaters Wind Farm, LLC on November 25, 2013.[32] With the addition of this transaction, I&M's total wind portfolio has grown to 450 MW, nameplate.

Q. COULD YET ADDITIONAL RENEWABLE RESOURCES, OVER-AND-ABOVE THIS 450 MW OF WIND RESOURCES, BE CONSIDERED A VIABLE DISPOSITION ALTERNATIVE FOR ROCKPORT UNIT 1 REPLACEMENT CAPACITY, IN LIEU OF THE SCR PROJECT?

A. As with incremental DSM, only to a limited degree. Given the intermittent nature of, for instance, wind resources, only a small percentage of the

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[31] "Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S."; Electric Power Research Institute (EPRI), January 2009.

[32] *See* Cause No. 44362.

"nameplate" capacity rating of wind is recognized by PJM for reliability/capacity resource adequacy planning purposes. In fact, PJM initially recognizes or "counts" only 13 percent of a wind resource's nameplate rating for such purposes. Therefore, wind resources, which can be a beneficial source of energy by adding diversity to a generating portfolio, cannot serve as a viable *capacity* replacement alternative in this instance. For example, in order to meet even just *one-tenth* of the Company's capacity obligation in lieu of Rockport Unit 1, nearly 860 MW (nameplate) of <u>additional</u> wind resources would be required over-and-above the 200 MW of wind resources the Company will already be adding by 2015.[33]

The same is true of solar resources. That is, PJM initially counts only 38 percent of a solar resources nameplate rating when establishing capacity contribution to meet load/demand and reserve margin obligations. So, again, in order to meet even just *one-tenth* of the Company's capacity obligation in lieu of Rockport Unit 1, nearly 300 MW (nameplate) of solar resources would be required.[34]

However, so as to be non-discriminatory as to the overall make-up of the available suite of resources to potentially replace Rockport Unit 1, the Company—as it did with incremental DSM—considered the prospect of renewable resources; namely, wind and utility-scale solar, as potential resource options from which the PLEXOS® long-term optimization modeling could select over the long-term optimization study period. As with incremental

[33] 1,118 MW x 1/10 = 112 MW / 0.13 (PJM [nameplate] installed capacity criterion limitation re wind resources) = 862 MW

[34] 1,118 MW x 1/10 = 112 MW / 0.38 (PJM [nameplate] installed capacity criterion limitation re solar resources) = 295 MW

DSM, however, this would recognize that, at best, such (incremental) wind or solar resources would be able to contribute only a small fraction of the capacity and energy lost by the retirement of Rockport Unit 1.

Q. PLEASE EXPLAIN WHY NATURAL GAS PRICING IS ONE OF THE KEY DRIVERS FOR THIS ANALYTICAL PROCESS.

A. In the electric utility industry, the natural gas-fired units often serve as the marginal cost, or "price-setting" units based on their relative higher position in a typical regional dispatch stack (relative to lower variable cost hydro, nuclear and coal-fired units). In PJM, that is most typically the case during "on-peak" hours.[35] Therefore, the price of natural gas will not only determine where gas-fueled units may fall in any regional dispatch stack, it will then largely determine the Locational Marginal Price (LMP) in which energy may clear in any market-based system such as PJM.

Typically, the higher the natural gas price, the higher gas-fired units—such as even thermally-efficient combined cycle units—would climb in PJM's dispatch stack; and then, depending upon contemporaneous load requirements and constraints, the higher the resulting market-based energy price/LMP might be. Based on that, margins or "spreads" available to more efficient coal-fired units could simultaneously be improved.

Conversely, the lower the gas price, the lower these CC units may fall in PJM's market-based dispatch/supply stack, thereby setting a lower clearing price for a greater number of hours/sub-hours. Under this latter outcome,

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[35] Although the definition varies, typically, on-peak hours represent a 16-hour per-day period M-F, 6AM-10PM, excluding holidays.

coal units could potentially be called upon to generate less energy at a lower available spread.

Q. WOULD YOU PLEASE OFFER AN OVERVIEW OF THE FORECASTED FUNDAMENTAL COMMODITY PRICING, INCLUDING NATURAL GAS, THAT WERE USED IN THE ROCKPORT UNIT 1 DISPOSITION ANALYSES?

A. As shown in **TABLE 3** below, an array of five (5) unique, long-term commodity pricing scenarios were utilized in the Rockport Unit 1 disposition analyses, consisting of a "base" view; two "price banding" sensitivity views; and two "CO_2" views:

TABLE 3

('BASE') "Fleet Transition (1H2013)" ... *reflecting:*

- Recognition of relatively lower fuel price trending due to proliferation of shale gas, increasing natural gas price elasticity; as well as capturing a likely implementation profile of environmental regulation including CSAPR, MATS Rule and potential carbon mitigation via a ~\$15/tonne[36] "carbon tax" (beginning in 2022).

Commodity Price Banding Scenarios…

2. Fleet Transition (1H2013) "HIGHER Band"…*same as the BASE case except:*

- Bounds the high-end of the BASE case with plausible fuels, emissions and energy pricing—with appropriate feedback for load response—and with such fuel prices varying by approximately a +1.0 standard deviation.

3. Fleet Transition (1H2013) "LOWER Band" ... *same as the BASE case except:*

- Likewise, bounds the low-end of the BASE case with plausible fuel, emissions and energy pricing, with such fuels prices varying by approximately a -1.0 standard deviation.

[36] The unit of measure representing a "metric" ton of CO_2 equal to 1,000 kilograms or 2,204 pounds.

CO_2 Pricing Scenarios…

4. Fleet Transition (1H2013) "No CO_2 Price"… *same as the BASE case except:*

- Removes the proxy carbon tax from the suite of commodity pricing; while then adjusting for the correlative effects on other commodities associated with that removal.

5. Fleet Transition (1H2013) "High CO_2 Price"… *same as the BASE case except:*

- Increases the scale of the relative carbon tax by a magnitude of approximately 60% (to ~$25 tonne).

The "*Base*-Fleet Transition (1H2013)" view reflects the most recent suite of long-term projection of commodity prices—inclusive of natural gas prices—performed by the AEP Fundamental Analysis group. This forecast was internally published in the August 2013 timeframe. Selected commodity pricing projections from that suite are reflected in Exhibit SCW-2. This Base-Fleet Transition view focused significantly on emerging natural gas pricing dynamics and considered evolving information that would support natural gas supply increases tied to the projected emergence of additional, significant levels of domestic shale gas at very competitive extraction costs.

This long-term view also assumes and embeds a "CO_2 pricing" impact as a result of potential carbon legislation or regulation (such as, by proxy, regulation of greenhouse gas emissions from *existing* fossil-fueled generating sources such as those recently set forth by the U.S EPA under Section 111(d) of the Clean Air Act). However, such legislation/regulation is not assumed to be effective until in or around the year 2022. This is largely in recognition of the presumed continued aversion in the U.S. Congress to passing comprehensive CO_2 legislation that would establish either a cap-and-trade mechanism or, as embedded in these analyses, a "carbon tax", coupled with another 5 years required to afford implementation (comparable to the implementation period set forth in prior unsuccessful carbon legislation such as Waxman-Markey or Kerry-Lieberman). From a regulatory perspective, this interim period is believed to be the significant time necessary to address the very likely legal challenges to such State or Federal Implementation Plans. Therefore, for planning purposes, an effective date of 2022 for any potential CO_2/carbon pricing proxies were recognized as being reasonable by Company management.[37]

VII. EVALUATION OF MODELING RESULTS

Q. BASED ON THESE INPUT PARAMETERS, WHAT WERE THE RESULTS OF THE ROCKPORT UNIT DISPOSITION ANALYSES PERFORMED IN PLEXOS®?

A. Exhibit SCW-4 offers a tabular summarization and comparison of the modeling results for the three primary disposition options for Rockport Unit 1, while Exhibits SCW-4A through 4E offer a broader view of the results for the "Base-Fleet Transition (1H2013)" and each of the four alternative commodity pricing scenarios defined in TABLE 3 above.

These modeling results represent **relative** cost analyses, meaning each are compared to one another in the determination of the "least-cost" alternative outcome. Given that, Exhibit SCW-4 reflects the relative costs of

[37] The Company and AEP's assumption/position around the prospect of a CO_2 carbon tax has been consistently assuming such a value/price in the AEP Fundamental Analysis group's "base" pricing projections since the '2008' vintage forecasts; through this most recent "1H2013" vintage forecast. The initial *timing* of such CO_2/carbon pricing in those earlier forecasts started around the year 2015, and has gradually migrated to the currently-assumed 2022 effective date; largely in recognition of the failure of Congress to pass CO_2/Climate Change legislation earlier this decade.

the alternative options that would call for the retirement and replacement of Rockport Unit 1 (Options #2A and #2B) when *compared to* a reference alternative. For purpose of these economic assessments, that reference alternative was established as Option #1 from TABLE 1; *i.e.,* the retrofit of Rockport Unit 1 with the SCR Project by December 31, 2017, *followed by* subsequent, (non-committed) additional environmental investments, including a DFGD retrofit by December, 2025.

Q. EXHIBIT SCW-4 INDICATES THAT OPTION #1 (CONTINUED ROCKPORT UNIT 1 OPERATION BEGINNING WITH THE SCR PROJECT IN 2017) HAS, BY FAR, THE LOWEST CPW OF NET UTILITY (GENERATION) COSTS OVER THE LONG-TERM PERIOD ANALYZED VERSUS <u>ALL OTHER</u> ALTERNATIVES UNDER ALL PRICING SCENARIOS PREVIOUSLY DESCRIBED. PLEASE ELABORATE ON THIS.

A. Exhibit SCW-4 offers an all-encompassing view of the relative modeling results for the evaluations performed in PLEXOS®. It is segregated into the five sets of future commodity pricing scenarios—displayed vertically—that were identified in TABLE 3, all vis-à-vis the Rockport Unit 1 SCR Project alternative (Option #1). Each of those pricing scenario views is offered individually as part of supporting Exhibits SCW-4A through 4E.

Focusing first on the relative disposition results under the "Base-Fleet Transition" commodity pricing scenario, it suggests that the Rockport alternative "Retire and Replace with PJM-market and then CC, CTs, IC engines and/or incremental DSM and renewables by 1/2019" (Option #2A) would be more costly than Option #1 by +$0.861 billion (+7.3 percent) over the long-term, life cycle study period. Moving down the exhibit to assess the "sensitivity" pricing scenarios, Option #2A is more costly by amounts ranging from +$0.691 billion (+5.6 percent) for the "High CO_2 Price" scenario; to +$1.153 billion (+10.7 percent) for the "No CO_2 Price" scenario.

Focusing next on the other Rockport Unit 1 disposition alternative modeled, the "Retire and Replace with PJM-market and then CC, CTs, IC engines and/or incremental DSM and renewables by 1/2025" (Option #2B) would be more costly than Option #1 by +$0.752 billion (+6.4 percent) under the "Base" pricing scenario. It also indicates that Option #2B is more costly by amounts ranging from +$0.612 billion (+5.0 percent) to +$1.064 billion (+9.9 percent); again under the same respective long-term "High CO_2 Price" and "No CO_2 Price" scenarios.

To provide some context for these relative CPW results, also note on Exhibit SCW-4 that for every $100 million CPW difference between any two options, there is $0.52 per Mwh levelized annual impact on I&M's net utility costs over the evaluation's long-term study period, expressed in 2014 dollars. For instance, when comparing Option #2A results under the "Base" pricing scenario, the resulting +$0.861 billion CPW variance would equate to a *levelized annual* impact on I&M's long-term generation cost profile of $4.47 per Mwh, in 2014 dollars (861 million / 100 x 0.52). Therefore assuming, for ease of demonstration, that this relative proxied net utility cost impact were to be applied equally to all I&M customer tariffs, a typical I&M Residential customer utilizing 1,000 kWh (1 Mwh) of energy per month would experience a relative G-rate impact of +$4.47 per month, every month—in today's dollars—over the *entire* affected future long-term study period <u>if</u> an alternative was chosen to retire Rockport Unit 1 and, ultimately, replace it with new resources *in lieu of* the Rockport Unit 1 SCR Project and subsequent projected additional environmental retrofit projects applicable to the unit.

Q. WHAT ADDITIONAL OBSERVATIONS AND CONCLUSIONS CAN YOU DRAW FROM THE ECONOMIC COMPARISON IN EXHIBIT SCW-4?

A. In general, the PLEXOS® results summarized in Exhibit SCW-4 indicate that, as compared to Option #2, the Rockport Unit 1 SCR Project is clearly economically-favored across the full range of long-term pricing scenarios modeled. Therefore, assessing these modeled CPW differences between Option #1 and Option #2 that are reflective of these significantly discrete pricing elements—e.g., inclusive of an approximate -1.0/+1.0 standard deviation around volatile natural gas pricing[38]—it would indicate that a nearer-term solution that would call for the retrofitting of Rockport Unit 1 with SCR technology by December 31, 2017, would by far be the most economical option for I&M and its customers versus the alternative "(PJM) market" with (subsequent) "metal-in-the-ground", new gas-build/DSM/renewable approaches.

Further, it suggests that the proposed Rockport Unit 1 SCR Project solution has effectively <u>preserved an option</u> for I&M and its customers to consider, in the future, additional possible retrofitting of Rockport Unit 1 with DFGD technology as set forth under the Modified Consent Decree.

[38] See TABLE 2 pricing scenario descriptions.

Q. FOCUSING AGAIN ON THE NEARER-TERM "PJM-MARKET PURCHASE" REPLACEMENT ALTERNATIVES (OPTIONS #2A AND #2B), WHAT ADDITIONAL CONCLUSIONS CAN BE DRAWN?

A. The Option #2B (Retire and Replace Rockport Unit 1 with PJM-purchased capacity and energy through *2025*, then with replacement natural gas capacity-builds with, potentially, incremental DSM and renewables) economic results reflected in Exhibit SCW-4 indicate it would be largely on par with the Option #2A view which would buy from the market through *2018 only*. That stated; both of these nearer-term market replacement options remain significantly more costly than the Company's proposed solution. Moreover, as discussed above, these 'Option #2' views are also potentially subject to additional market pricing and performance risks. As highlighted previously in this testimony, AEPSC and I&M have continued to "opt-out" of the PJM RPM capacity construct due to such market price risk concerns, among others.

VIII. <u>VALIDATION OF RESULTS / ADDITIONAL RISK ASSESSMENT</u>

Q. YOU SUMMARIZE THAT THE ROCKPORT UNIT 1 DISPOSITION ANALYSES PERFORMED IN PLEXOS® CONSIDERED VARIATIONS IN NATURAL GAS AND ATTENDANT ENERGY PRICING. WHAT ADDITIONAL KEY RISK FACTORS REQUIRE CONSIDERATION?

A. In addition to price risk around natural gas and energy, another major variable in such disposition analyses would be construction cost and performance risk surrounding the available resource alternatives.

Q. WHAT STEPS HAS THE COMPANY TAKEN TO ADDRESS THE COST TO CONSTRUCT ANY OF THE ALTERNATIVES THAT WERE ASSESSED AS PART OF YOUR ECONOMIC MODELING?

A. As addressed in more detail in the direct testimony of Company witness Walton, prudent steps have been taken to establish a reasonable level of retrofit construction cost certainty around the Rockport Unit 1 SCR Project (Option #1). With regard to the ultimate replacement 'CC/CTs/IC engines/incremental DSM and renewables' alternative (Option #2), the Company has relied largely on previously-established AEPSC internal cost estimates developed by the AEP Generation organization.

Q. DESPITE THE DILIGENCE THAT HAS BEEN UNDERTAKEN BY I&M TO ESTABLISH REASONABLE ESTIMATES AROUND FUTURE RETROFIT AND NEW-BUILD CONSTRUCTION COSTS, HAVE ADDITIONAL DISCRETE ECONOMIC ANALYSES BEEN PERFORMED TO ASSESS THIS CONSTRUCTION COST RISK?

A. Yes. A "break-even" installed cost calculation was performed that determined a relative economic point of indifference (*i.e.*, a subsequently changed installed cost level that would result in the relative CPW differentials identified on Exhibit SCW-4 between Option #1 and Option #2A being "zero" dollars.) These sensitivity analyses were performed from both the perspective of the estimated "full" cost of the various subsequent environmental retrofit capital spend requirements associated with Rockport Unit 1 (TABLE 2; Option #1); and from the perspective of the estimated capital spend associated with new-build, comparably-sized CC unit replacements by 2019 (TABLE 2; Option

#2A). As summarized on TABLE 2, the Rockport Unit 1 SCR, and potential subsequent total Rockport Plant DFGD and "NPDES/CCR/ELG/316(b)" estimated installed costs—with all estimated production overheads, but excluding AFUDC—total \$995 per kW. Comparatively, the, new-build CC unit installed costs are \$1,106 per kW—again, with all overheads, but excluding AFUDC—with each represented in '2013' dollars. Setting aside the natural *variable cost* benefit of a controlled Rockport facility, with its lower 'dollar per MMBtu' fuel costs versus that of a natural gas-fired CC, the fixed/installed cost benefit of a long-term Rockport solution is over 11 percent (1,106 / 995 - 1).

Q. PLEASE DESCRIBE THE RESULTS OF THIS DISCRETE CONSTRUCTION COST SENSITIVITY ANALYSIS WHEN ASSESSING THE POSSIBILITY OF INSTALLING A NEW-BUILD NATURAL GAS CC OPTION BY 2019 (OPTION #2A).

A. Based on the modeling results reflected on Exhibit SCW-4, it would suggest that under the "Base-Fleet Transition" long-term commodity pricing scenario, the estimated capital cost of the combined Rockport Unit 1 SCR + Rockport Unit 1 DFGD + (total Rockport Plant) "NPDES/CCR/ELG & 316(b)"-related retrofits would have to <u>increase</u> from the current total project installed cost estimates reflected on TABLE 2 by a magnitude of nearly 67 percent, or by +\$1.040 billion as-spent dollars (excluding AFUDC) before the relative PLEXOS®-determined CPW cost premium associated with Option #2A (versus Option #1) would decline from the currently projected +\$0.861 billion figure, to zero.

Conversely, viewed from the perspective of the installed cost of a Rockport Unit 1 replacement CC-build option (Option #2A), it would suggest that the cost of any required replacement CC capacity-build by 2019 would have to be reduced from the current cost estimates reflected on TABLE 2 by over 67 percent, or by \$0.766 billion as-spent dollars (excluding AFUDC), before that PLEXOS®-determined relative CPW economic cost premium associated with Option #2A would achieve that same point of indifference versus Option #1.[39] Stated another way, this means that in order for a 'CC-build' replacement option to be less expensive than a Rockport Unit 1 long-term retrofit solution, that "break-even" CC cost could be no greater than just *\$329 per kW* (2013 dollars).

Q. BASED ON THIS 'COST-TO-CONSTRUCT' SENSITIVITY ANALYSES, WHAT FURTHER CONCLUSIONS CAN YOU DRAW?

A. These respective "break-even" results surrounding the necessary decision-altering shifts in capital cost estimates that would be forced to manifest clearly represent differences of huge proportions. Considering also that these analyses were performed independently, meaning the costs of the "other" alternative (be it "Retrofit" *or* "Replacement CC") were assumed to be held constant, those differences are even more pronounced. In fact, if upward—or downward—cost pressures were to be experienced that would influence metals and alloys, certain equipment and components, or even craft labor; such cost migrations would likely impact *both*—not just one—of those

[39] This sensitivity analysis assumes that the attendant costs of any CT, IC engine and/or incremental DSM and renewables that would comprise an "Option 2A" replacement resource view, in combination with a CC, would not change.

construction alternatives (*i.e.*, such installed costs would more likely tend to move in unison among alternatives).

Q. IN ADDITION TO COST TO CONSTRUCT, ANOTHER RISK FACTOR TO CONSIDER AS PART OF THIS ROCKPORT 1 UNIT DISPOSITION EVALUATION FOCUSES ON THE IMPACT OF "CO_2/CARBON". WITH THE RECENT ANNOUNCEMENT BY EPA OF THE "CLEAN POWER PLAN" WHICH ESTABLISHED FUTURE, STATE-SPECIFIC CO_2 EMISSION RATE TARGETS IN RESPONSE TO SECTION 111(d) OF THE CLEAN AIR ACT, HOW WAS THAT RISK FACTOR ADDRESSED?

A. As discussed in TABLE 3 and immediately thereafter, the Company considered—as a cost/valuation "proxy" for modeling purposes—a presumed "carbon tax" effective in the year 2022. As identified on Exhibit SCW-2, the level of this carbon tax that was incorporated into the long-term fundamental pricing forecast initiates on the order of $15 per tonne and was incorporated for not only the 'Base' alternative pricing scenario, but was also applied to the respective 'LOWER Band' and 'HIGHER Band' alternative scenarios. Hence, the modeling results inherently considered the relative cost "penalty" attributable to the generation costs of higher-CO_2 emitting coal-fired resources—such as Rockport Unit 1—vis-à-vis other (non-coal) resource alternatives.[40] Recognizing this penalty, however, the PLEXOS® long-term, life cycle study period results previously summarized continued to point to "Option 1" as easily being the least-cost unit disposition option for Rockport 1.

[40] It is important to realize, however, that such CO_2 pricing assumptions would naturally have correlative impacts on other commodity pricing; namely the price of natural gas and the price of (PJM) energy.

Q. WERE THE IMPLICATIONS OF EPA'S RECENTLY-RELEASED CLEAN POWER PLAN SPECIFICALLY REFLECTED IN THE MODELED ECONOMIC EVALUATIONS FOR ROCKPORT UNIT 1?

A. No, not specifically. Given that the Section 111(d) proposed rulemaking was only recently released[41] and given its underlying complexity and anticipated significant debate, no separate attempt was made to specifically address/model elements of the proposed rule. The proposed rule did not seek to establish a carbon price, or "tax", in order to achieve reduction of CO_2 emissions from fossil generation units. Rather, as more fully described by Company witness Hendricks, the proposed rule is centered on the achievement of future state-specific CO_2 emission reduction targets that were predicated on a set of suggested "building block" metrics. Because of that complexity and uncertainty, it is the Company's position that it would be necessary to attempt to reasonably 'proxy' the potential relative economic implication on Rockport Unit 1 by way of assessing the deleterious impact of such "CO_2 pricing". This was accomplished by way of the (incremental) variable/dispatch cost penalization of the coal-fired Rockport Unit 1 vis-à-vis the other (non-coal) alternatives examined from TABLE 1 via the introduction of a CO_2 pricing proxy. By way of incorporating the pricing proxies I will further describe, the Company contends it has adequately captured any potential impact of the Clean Power Plan.

Q. HOW WERE SUCH CO_2 PRICING (PROXY) LEVELS CONSIDERED THAT WOULD POSSIBLY DIMINISH THE CLEARLY-ESTABLISHED ECONOMIC

[41] Publically released on June 2, 2014; and published in the *Federal Register* on June 18, 2014.

ADVANTAGE OF AN ENVIRONMENTALLY-RETROFITTED ROCKPORT UNIT 1?

A. As shown on TABLE 3, the PLEXOS® modeling also considered a unique commodity pricing scenario that assumed a “High CO_2 Price”. For purposes of this exercise, the AEP Fundamental Analysis group determined that threshold to be a level of CO_2 pricing approximately two-thirds higher than the level assumed in the ‘Base’ pricing scenario, or at an adjusted level beginning at approximately *$25* per tonne, also effective in the year 2022.

Q. WHAT DID THOSE PLEXOS® MODELING RESULTS INDICATE?

A. As previously summarized in this testimony and on Exhibit SCW-4, the Option #1 alternative continued to be significantly economically advantaged versus either of the “Option 2” (retire and replace) alternatives by amounts ranging from $0.612 billion (vs. Option 2B) to $0.691 billion (vs. Option 2A) under this “High CO_2 Price” scenario.

Q. WHAT MIGHT THAT ULTIMATE *EXTREME* CO_2 PRICE BE THAT COULD POTENTIALLY RESULT IN A ROCKPORT UNIT 1 DISPOSITION ECONOMIC “BREAK-EVEN” BEING ACHIEVED VERSUS THOSE ‘OPTION 2’ ALTERNATIVES?

A. In order to establish such CO_2 pricing levels, the AEP Fundamental Analysis group sought to re-model such an extreme scenario within its long-term commodity pricing modeling process. The correlated results of that “*Ultra* High CO_2 Price” scenario exercise are reflected on Exhibit SCW-5, page 1 of 2. It would suggest that this ‘Ultra High’ CO_2 pricing level that could ultimately result in the significant curtailment of the relatively more highly-efficient coal-fired generating units, such as Rockport Unit 1, was an order-of-magnitude price initially at $77 per tonne.[42]

Q. BASED ON THE ESTABLISHMENT OF THAT ADDITIONAL "ULTRA HIGH CO_2" LONG-TERM FUNDAMENTAL PRICING ASSESSMENT, WHAT ADDITIONAL STEPS WERE TAKEN?

A. A new economic case was executed in PLEXOS® reflecting this "Ultra High CO_2 Price" scenario for each of the disposition options initially summarized on TABLE 1 of this testimony.

Q. WHAT WERE THE RESULTS OF THAT ADDITIONAL PLEXOS® EVALUATION?

A. As shown on Exhibit SCW-5, page 2 of 2, the results of that additional PLEXOS® evaluations indicate that Option #1 would continue to be selected; although the relative cost 'advantages' of Option 1, versus either of the Option #2 alternatives, were much smaller than previously summarized. Specifically, compared to 'Option 2A' the Rockport Unit 1 retrofit option—again, inclusive of all subsequent anticipated retrofit requirements, as before—would be reduced to only $79 million, or +0.56 percent (from the $861 million level under the previously-summarized 'BASE CO_2 Price' scenario which was reflective of a $15 per tonne CO_2/carbon price proxy).

Objectively, this would also indicate that a true "break-even" CO_2/carbon price for purposes of this sensitivity exercise would be slightly higher than the (initial 2022) $77 per tonne price utilized; on the order of magnitude of *$85* per tonne.

[42] This CO_2 price escalates to well over $100/tonne by the end of the 2040 long-term optimization period modeled.

Q. IN SUMMARY, AND IRRESPECTIVE OF HAVING OFFERED THIS CO_2/CARBON PRICE SENSITIVITY ANALYSIS, IN YOUR OPINION, IS AN INITIAL $77 PER TONNE PRICE—LET ALONE AN $85 PRICE—FOR CO_2 TENABLE?

A. No. Given the prospect that such CO_2 pricing/equivalent-valuation could conceivably result in massive coal-unit retirements or, minimally, the potential for severe output curtailments and reliability exposures within PJM (and elsewhere), as a practical matter it would seem to be an inconceivable threshold. According to the U.S. Department of Energy-Energy Information Administration ("EIA"), today over 40 percent of the nation's generated electricity is sourced from coal-fired units.[43] The EIA also projects that the relative "mix" of coal-based resources will remain well above 30 percent throughout a period that is comparable to the modeled optimization period in the Company's analysis—2040.[44] Recognizing that a $85 per tonne CO_2 pricing strata could drastically impair the production of coal-based electricity generation on relatively more efficient units, the notion that within the next 5-10 years a carbon tax—or an equivalent economic proxy for such a tax as predicated upon the recently-proposed EPA 111(d) rulemaking—could begin to contemplate such a threshold level would seem to be remote. Similarly, the prospect of customers incurring correlated PJM *energy* prices that would be forced to increase by as much as +83 percent during 'on-peak' hours; and <u>*more than double*</u> (+116 percent) during 'off-peak' hours (both relative to a

[43] http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014ER&subject=0-AEO2014ER&table=8-AEO2014ER&region=0-0&cases=full2013-d102312a,ref2014er-d102413a
[44] *ibid* (Note the EIA's "Annual Energy Outlook-2014 Early Release" establishes this coal-source mix at approximately 33% by 2040.

"No CO_2" pricing scenario, as summarized on Exhibit SCW-5, page 1 of 2), is likewise remote given the potential devastating impact such electricity price increases could have on its consumers, and commerce in general.

As previously discussed, recognizing that the proposed Clean Power Plan was only recently released and could be subject to significant debate and modification, it is not plausible to provide a set of assumptions that would accurately capture the ultimate impact of this rulemaking. That said, the Company contends that the huge range of carbon price "proxies" analyzed—from $0 -to- as much as a (non-tenable) $85/tonne, levelized, pricing level—clearly offers an extremely broad bandwidth. Using this wide 'carbon price proxy' sensitivity, in <u>all</u> cases the economic modeling supporting the environmental retrofit of Rockport Unit 1 *continues* to be on par or superior to the alternative options evaluated. Therefore, based on any reasonable (or even 'extreme') proxied CO_2 rulemaking-equivalent "tax", *or any equivalent carbon intensity reduction bases*, it is reasonable to assume that the relatively more efficient Rockport Unit 1 (and Rockport Unit 2) will continue to operate well into the future.

Q. PLEASE SUMMARIZE THESE RISK ASSESSMENTS.

A. In summary, it could be concluded that the pursuit of an ultimate "full" retrofit option for Rockport Unit 1—even *beyond* the very economic SCR Project at issue in this case—has significant advantages, particularly after considering the relative impacts associated with three of the more critical "driving" economic risk parameters: the potential future price of natural gas and attendant energy pricing, the future costs to construct (or purchase) either of the available resource options, and the introduction of a wide range of a CO_2/carbon pricing proxy.

IX. OPTIONALITY OFFERED BY THE ROCKPORT UNIT 1 SCR PROJECT

Q. YOUR TESTIMONY HAS PREVIOUSLY MENTIONED THE "OPTIONALITY" THAT WOULD BE AFFORDED I&M AND ITS CUSTOMERS BASED ON A DECISION TO ALLOW ROCKPORT UNIT 1 TO CONTINUE TO OPERATE BY WAY OF INSTALLING THE SCR PROJECT. PLEASE ELABORATE.

A. As previously discussed, the Rockport Unit 1 SCR Project will effectively serve to "bridge" the unit for a period of at least 8 years; beginning from the required December 2017 SCR in-service date up to the timeframe in which a much more capital-intensive DFGD would be required to be installed at the end of 2025 (or 2028). For instance—as outlined on TABLE 2 of this testimony—at an installed capital cost of just $158/kW, the Rockport Unit 1 SCR Project would be just a fraction of the cost of either replacement new-build CC, CT and/or IC resources; *or* the likely acquisition price of any existing generating asset(s) available for purchase. Considering then also the attendant variable cost benefit that would come with this efficient Rockport unit would further compound that economic advantage during this timeframe.[45]

[45] This statement is based on the fact that, on a "$ per MMBtu basis", the cost to dispatch a Rockport unit (fuel and consumables) is, roughly 50-60% of the comparable cost to deliver natural gas to a gas-fired facility. Even after considering any attendant advantages in thermal efficiency (*i.e.*, heat rate) of a CC unit, the overall significant dispatch (variable) cost advantage of Rockport is maintained.

Q. PLEASE ELABORATE FURTHER ON THE ECONOMIC ADVANTAGE OF AN SCR-RETROFITTED ROCKPORT UNIT 1 VERSUS ALTERNATIVE OPTIONS DURING THE "BRIDGE" PERIOD (THROUGH 2025) PREVIOUSLY HIGHLIGHTED,

A. Exhibit SCW-6, offers a shorter-term (*i.e.*, 12-year; 2014-2025) CPW comparison of the Option 1 versus Option 2 alternatives. It demonstrates that the relative economic advantage of Option 1 versus Option 2A over this shorter (2025) timeframe is even *more* pronounced, with the CPW benefit being, on average, $59 million per year—compared to an average per year advantage of $27 million over the modeled long-term optimization period through 2040.

Likewise, the relative economic advantage of Option 1 over this 2014-2025 timeframe was also significant when comparing to Option 2B; with the CPW benefit being, on average, $36 million per year. This compares to an average per year advantage of $22 million over the full evaluated life-cycle optimization study period.

In summary, this would suggest that the Rockport Unit 1 SCR Project would offer *significant* relative option value over the period leading up to the next major re-investment; the installation of DFGD by the end of 2025 (or 2028).

X. CONCLUSIONS AND RECOMMENDATIONS BASED ON THESE ANALYSES

Q. DO THE ROCKPORT UNIT 1 DISPOSITION ANALYSES YOU HAVE DESCRIBED EXAMINE THE CRITERIA SET FORTH IN INDIANA CODE § 8-1-8.7-3(b)(7) AND § 8-1-8.7-3(b)(8)?

A. Yes. As it pertains to part (b)(7), the Company has set forth the relative cost and feasibility of a Rockport Unit 1 retirement option and demonstrated that the cost of that alternative would likely significantly exceed that of the proposed Rockport Unit 1 SCR Project.

In regard to part (b)(8), the Company has likewise implicitly set forth that the dispatch priority of this proposed NO_X-controlled Rockport Unit 1 will not be adversely impacted based on the resulting variable cost profiles within the economic analyses previously described. It would be anticipated that the unit's annual capacity factor will not be significantly different from levels had this SCR retrofit not been installed.

Q. PLEASE SUMMARIZE YOUR TESTIMONY FROM THE PERSPECTIVE OF THE "UNIT DISPOSITION ANALYSES" PERFORMED.

A. Several final summarizations and conclusions can be drawn from the information offered as part of this testimony:

(1) I&M has performed robust unit disposition economic analyses that would point to the nearer-term retrofitting of Rockport Unit 1 with SCR technology by December 31, 2017 (Option #1) as being the most reasonable and least-cost solution over the long-term economic study period evaluated; when compared to either a combination PJM market-based solution with a nearer-term (2019) comparably-sized new-build "natural gas"

alternative(s) with, potentially, incremental DSM and renewables (Option #2A), or a solution that would rely on such PJM market-based resources over a longer-term (2025), before comparably-sized new-build natural gas alternatives were introduced (Option #2B).

(2) I&M affirms this "Rockport Unit 1 SCR Project" would serve to economically preserve a future option to install DFGD environmental controls on Unit 1, possibly by the end of 2025, as stipulated under the Modified Consent Decree. However, even under the assumption I&M would ultimately choose *not* to proceed with a Unit 1 DFGD retrofit, the economic analysis clearly supports implementation of the Rockport Unit 1 SCR Project.

(3) I&M affirms that, holistically, this ultimate "suite" of Rockport environmental retrofits—beginning with the previously-approved Rockport (Units 1 and 2) DSI Project, and now this Rockport Unit 1 SCR Project under consideration—is, based on initial cost estimations of such subsequent potential retrofit project activity, clearly superior to *either* the Option #2A or Option #2B alternatives analyzed under an array of long-term commodity pricing scenarios and after considering reasonable expectations for construction cost variability, as well as any remote prospect for an extremely high future CO_2/carbon pricing scenario.

(4) I&M also affirms the nearer-term economic optionality offered by the Rockport Unit 1 SCR-CCT Project by virtue of its low relative installed cost versus the installed cost of any required replacement resource.

(5) I&M confirms that it is in the best interest of its customers to leverage the current investment of a relatively young, thermally-efficient Rockport Unit 1 by recommending it be retrofitted with

SCR technology by December 31, 2017, so as to be in compliance with the Modified Consent Decree as well as other potential EPA rulemaking that would require the reduction of NO_X emissions.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

I, Scott C. Weaver, Managing Director – Resource Planning & Operational Analysis of the American Electric Power Service Corporation, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Date: August 13, 2014

Scott C. Weaver

Exhibit SCW-1

Overview of resource planning-related criteria used in I&M’s analyses

I. BACKGROUND AND GOVERNANCE

A. Overview of the historical interrelationship between I&M and AEP for purposes of capacity resource planning

The AEP System includes ten utility operating companies, operating in eleven states, with generation and transmission assets in, primarily, two different Regional Transmission Organization ("RTO") planning and operational regions. Those RTOs are the PJM Interconnection, L.L.C. ("PJM"), in AEP's eastern zone, and the Southwest Power Pool ("SPP") in its western zone. I&M is a wholly-owned subsidiary of AEP—serving retail customers in Indiana and Michigan—and is located in its eastern or PJM zone. In addition to I&M, the AEP Operating Companies comprising this eastern zone (collectively, "AEP-East") consist of:

- Appalachian Power Company ("APCo"), serving large portion of West Virginia, and western Virginia;
- Kentucky Power Company ("KPCo"), serving portions of eastern Kentucky; and
- Ohio Power Company ("OPCo"), serving portions of Ohio.[1]

In addition, two additional Operating Companies residing in this eastern zone, Kingsport Power Company and Wheeling Power Company represent non-generating affiliates.

AEP-East collectively serves about 3.6 million customers in an approximate 90,000 square-mile area of Indiana, Michigan, Kentucky, Virginia, West Virginia, Ohio, and Tennessee.

B. AEP Pool transition

Historically, the projected capacity resource needs for I&M were established in concert with that of AEP-East under the auspices of the AEP Interconnection Agreement ("AEP Pool"), which was established "(f)or the purposes of obtaining the most efficient coordinated expansion and operation of their electric power supply facilities…"[2]. This includes the coordinated and integrated determination of

[1] OPCo and the former affiliate operating company Columbus Southern Power Company ("CSP") were legally merged effective January 1, 2012.
[2] Article 4.1 of the AEP Interconnection Agreement.

load and (peak) demand obligations for I&M and each of the other Member Companies defined in that agreement (APCo, CSP, KPCo, and OPCo).

On October 31, 2012, various filings were made with the Federal Energy Regulatory Commission ("FERC") which sought to, among other things:

- Terminate the previous AEP Pool and, in its place, enter into a Power Coordination Agreement ("PCA") with the remaining regulated, vertically-integrated AEP-East Operating Companies (APCo and KPCo).

Through the PCA, I&M will essentially be a "stand-alone" entity for purposes of planning for, and ultimately achieving its customers' capacity and energy resource needs going-forward. On December 23, 2013 the FERC approved the PCA.

II. RESOURCE NEED

A. Description of I&M's customer base

I&M's customer base consists of both retail and sales-for-resale customers located in northern Indiana and southern Michigan. Approximately 586,000 residential, commercial, industrial and other retail end-use customers are served by the Company; with approximately 458,000 residing in Indiana. These I&M-Indiana retail customers represent over 66 percent of I&M's total (retail and wholesale) energy sales in 2013, with the balance coming from retail sales to customers in Michigan, as well as FERC-authorized sales to several electric cooperatives and municipalities that provide wholesale service for ultimate distribution and resale to their end-use customers.

B. Overview of I&M's peak demand requirements

To ensure the continuation of reliable service, the peak demand of its customer base represents one of the primary underpinnings of any capacity resource plan. The peak load requirement of all I&M retail and sales for resale wholesale customers is seasonal in nature, with distinctive peaks occurring in both the summer and the winter seasons. Historically, I&M's larger peak demand has been recorded in the summer season, with the all-time actual peak being 4,837 MW, which occurred on July 21, 2011 (4,388 MW on a "weather-normalized", non-PJM coincident basis).[3]

The following **Table 1-1** offers the latest (July-2013) AEP Economic Forecasting projection of I&M and, for comparison, overall AEP-East (summer) peak demand and internal load, with peaks adjusted to recognize overall PJM zonal diversity. Over the next 10 year period (through 2023) I&M's summer demand is anticipated to increase by a compound annual growth rate ("CAGR") of 0.32 percent, or by a total of 122 MW; relative results which are slightly below those of the overall AEP-East region for the same period. The peak demand CAGR for I&M increases to 0.46% over the next 20 years, or by a total of 383 MW.

Table 1-1

Projected (Summer) Peak Demand and Internal Load
I&M and AEP-East
Internal Forecast BEFORE DSM, with Implied PJM (Peak) Diversity Factor
(July-2013 Fcst)

	Peak Demand (MW)			Internal Load (GWh)	
Year	**I&M**	AEP-East*	Year	**I&M**	AEP-East*
2014	**4,219**	19,643	2014	**25,277**	118,214
2015	**4,229**	19,767	2015	**25,354**	118,919
2016	**4,224**	19,849	2016	**25,351**	119,483
2017	**4,237**	19,935	2017	**25,377**	119,877
2018	**4,243**	20,018	2018	**25,387**	120,240
2019	**4,256**	20,103	2019	**25,458**	120,720
2020	**4,264**	20,174	2020	**25,528**	121,201
2021	**4,297**	20,345	2021	**25,646**	121,813
2022	**4,320**	20,478	2022	**25,761**	122,462
2023	**4,341**	20,565	2023	**25,894**	123,104
2024	**4,352**	20,639	2024	**25,997**	123,675
2025	**4,388**	20,822	2025	**26,129**	124,317
2026	**4,411**	20,957	2026	**26,240**	124,955
2027	**4,437**	21,103	2027	**26,374**	125,645
2028	**4,455**	21,213	2028	**26,504**	126,355
2029	**4,491**	21,372	2029	**26,662**	127,144
2030	**4,519**	21,535	2030	**26,803**	127,934
2031	**4,548**	21,689	2031	**26,952**	128,670
2032	**4,563**	21,780	2032	**27,077**	129,314
2033	**4,602**	21,966	2033	**27,216**	129,937

10-Year (2014-2023):			10-Year (2014-2023):		
Total Growth	**122**	922	Total Growth	**617**	4,890
Compound Annual Growth Rate	**0.32%**	0.51%	Compound Annual Growth Rate	**0.35%**	0.58%

20-Year (2014-2033):			20-Year (2014-2033):		
Total Growth	**383**	2,324	Total Growth	**1,939**	11,723
Compound Annual Growth Rate	**0.46%**	0.59%	Compound Annual Growth Rate	**0.39%**	0.50%

* AEP-East includes Ohio-Wires customers

[3] I&M's most recent annual (2013) actual summer peak was 4,540 MW, occurring on July 6, 2013 (4,438 MW on a weather-normalized, non-PJM coincident basis).

C. PJM reserve margin criterion

It is assumed that the underlying minimum reserve margin criteria to be utilized in the determination of AEP-East and, ultimately, I&M capacity needs assessment is the current PJM board-approved Installed Reserve Margin ("IRM") level of 15.7 percent.[4]

D. I&M and AEP obligation to provide reserve margin in PJM

On October 1, 2004, AEP transferred functional control of its transmission facilities as well as its generation dispatch, including the transmission and generation facilities owned by its operating companies, including I&M, to PJM. With that, the PJM Reliability Assurance Agreement defines the requirements surrounding various reliability criteria, including measuring and ensuring capacity adequacy. In that regard, each Load Serving Entity ("LSE") in PJM is required to provide an amount of capacity resources determined by PJM based on several factors, including PJM's IRM requirement. This requirement is itself based on the amount of resources needed to maintain, among other things, a loss-of-load expectation of one day in ten years. Additionally, peak demand diversity among the LSEs and PJM, and generating asset-assumed equivalent forced outage rates ("EFOR") represent other factors impacting such required minimum reserve levels.

Further, beginning in the initial 2007/08 PJM "planning year", through today—*i.e.,* for the most recently-established 2017/18 planning year—AEPSC, as agent for the AEP-East LSEs, including I&M, has given annual notice of its intent to elect to continue to opt-out of the PJM Reliability Pricing Model ("RPM") three-year forward capacity auction and, instead, meet its capacity resource obligation through participation in the optional, FERC-authorized Fixed Resource Requirement ("FRR") construct. FRR requires AEP and I&M to set forth its future capacity resource profile and position under, essentially, a "self-planning" format that is predicated upon ensuring the stand-alone achievement of its future customer peak demand *plus* IRM requirements (*i.e.*, 'UCAP Obligation'). As previously mentioned, the PCA offers a loosely-integrated arrangement in which the

[4] As established by PJM beginning with the 2016/17 for non-capacity auction, Fixed Resource Requirement entities such as AEP. For purpose of the I&M stand-alone modeling exercise to be discussed throughout this testimony, it is assumed this 15.7% IRM level would remain constant going-forward.

participating operating companies (I&M, APCo and KPCo) are expected to be self-sufficient for both capacity and energy requirements. Despite that PCA requirement, these three AEP affiliates have continued to elect to opt-out of the capacity auction and participate jointly as an "FRR" planning entity, at least through the 2017/18 Planning Year, so as to enjoy a) the inherent capacity position hedging capabilities offered to a larger-scale planning entity; and b) a lower overall IRM requirement vis-à-vis the implied reserve margin that have resulted from prior cleared RPM capacity auctions.

Currently it is I&M's position that the interests of its customers are better preserved under that FRR framework. While I&M, and the other AEP-East operating company participants in the PCA—beginning with the *next* (2018/19) PJM-RPM planning year—reserve the option of electing to participate in future RPM 3-year forward auction process.

E. I&M's current available capacity resources

To meet the most recent UCAP Obligation and annual energy requirements of its customers, as part of its FRR obligations in PJM for the upcoming 2014/2015 "delivery year", I&M is relying on 5,479 MW of owned—or for which it currently has a long-term purchase entitlement—generating capability. The make-up of I&M's PJM-recognized installed capability ("ICAP") includes a portfolio of coal facilities identified in the following **Table 1-2**:

Table 1-2

COAL:

- ✓ Rockport Unit 1 (658 MW) located in Spencer County, IN. In-service 1984
- ✓ Rockport Unit 2 (650 MW) located in Spencer County, IN. In-service 1989
- ✓ Rockport Unit 1 (460 MW) located in Spencer County, IN. [5] In-service 1984
- ✓ Rockport Unit 2 (455 MW) located in Spencer County, IN. [6] In-service 1989
- ✓ Tanners Creek Unit 1 (145 MW) located in Lawrenceburg, IN. In-service 1951
- ✓ Tanners Creek Unit 2 (142 MW) located in Lawrenceburg, IN. In-service 1952
- ✓ Tanners Creek Unit 3 (195 MW) located in Lawrenceburg, IN. In-service 1954

[5] This reflects I&M's 70% purchase entitlement from the (50%), AEP Generating Company (AEG) ownership share of the (total) 1315 MW unit.
[6] This reflects I&M's 70% purchase entitlement from the (50%), AEG share of the 1300 MW unit that is currently under lease to non-affiliate Lessors.

- ✓ Tanners Creek Unit 4 (500 MW) located in Lawrenceburg, IN. In-service 1964

NUCLEAR:
- ✓ D.C. Cook Unit 1 (1,007 MW) located in Bridgeman, MI. In-service 1975
- ✓ D.C. Cook Unit 2 (1,057 MW) located in Bridgeman, MI. In-service 1978

HYDRO:
- ✓ (41) small, run-of-river units (18 MW total) located at 6 facilities in IN & MI

WIND [7]:
- ✓ Fowler Ridge Wind Farm (13 MW) located in Benton County, IN. In-service 2009
- ✓ Wildcat Wind Farm (13 MW) located in Grant, Howard, Madison and Tipton Counties, IN. In-service 2013

Plus:
- ✓ I&M's 7.85 percent (~166 MW) power participation ratio (PPR) share if the Ohio Valley Electric Corporation's (OVEC) Clifty Creek and Kyger Creek coal-fired facilities (2,140 MW, combined), located in southern IN and southern OH, respectively.

TOTAL (2013/2014 PJM Planning Year) **5,479** MW

F. Future capacity rerates

Nearly concurrent with the planned Rockport Unit 1 (and Unit 2) SCR retrofits in late-2017 and late-2019, respectively, current planning also projects both units would be uprated by a total of 36 MW (each) to reflect the benefits of the AEP System's LP Turbine improvement program. Likewise, D. C. Cook Unit 2 is projected to experience a 50 MW uprate in late-2016 to reflect a currently-planned HP/LP Turbine replacement. Such uprates would impact the Company's ICAP beginning with the subsequent PJM-RPM planning years.[8]

G. I&M's current available "demand" resource (DSM)

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[7] Recognizing the intermittent nature of wind resources, for PJM ICAP-determination purposes, this represents the PJM-recognized initial 13 percent portion of the total nameplate rating from I&M's share of the (150-MW, combined) Fowler Ridge I & II Renewable Energy Purchase Agreements (REPA), and the (100-MW) Wildcat REPA. Note, however, that the subsequent PJM-authorized capacity rating for I&M's share of Fowler I & II has been decreased to a total of 13 MW from the initial in-service recognized level of 19.5 MW (150 MW x 13%). Further, this current (2014/15) PJM delivery year portfolio would also not yet reflect the Company's projected purchases from the 200-MW, nameplate (26-MW PJM-initially recognized capacity value) Headwaters Wind Farm, LLC, anticipated to be in-service in December, 2014.

[8] For example, the Rockport Unit 1 uprate in "late-2017" would impact I&M's capacity position beginning with the 2018/19 PJM-RPM planning year.

Demand-Side Management ("DSM") comprised of both "active" and "passive" demand reduction initiatives has been incorporated into the Company's resource planning. Specifically, "active" DSM, in the form of peak-reducing demand response activity has been projected; as well as "passive" DSM, in the form of "around-the-clock" energy efficiency ("EE") programs, which I&M and this Commission has supported for some time, has also been incorporated in the plan. The following **Table 1-3** identifies the level of I&M (total) demand reduction and EE that are initially anticipated over the forecasted time horizon based, in part, on the potential profile for DSM in Indiana as set forth in Cause No. 42693 approved in December, 2009. Such projected levels of EE were embedded into the Company's load forecast itself.

While not at all trivial, it is evident however, that even the aggressive demand resource contributions already projected for such DSM activity by or around the year 2020 of approximately 490 MW are well below the significant capacity needs that would be at issue when considering the disposition of units on the scale of, particularly, Rockport Unit 1. Likewise, any *incremental* levels of EE activity over-and-above the projected levels incorporated into I&M's long-term load forecast—and summarized in Table 1-3—that could result from the unit's disposition evaluation would also likely provide a very small relative offset to the native generation offered by Rockport Unit 1.

Table 1-3

Projected Demand Response (DR) and Energy Efficiency (EE)
I&M and AEP-East
(July-2013 Fcst)

	(CURRENT) PJM-APPROVED INTERRUPTIBLE DEMAND RESPONSE Peak Reduction (MW)		+ (PROJECTED) "ACTIVE" DEMAND RESPONSE Peak Reduction (MW)		+ (PROJECTED) "PASSIVE" DEMAND RESPONSE (ENERGY EFFICIENCY) Peak Reduction (MW)		= TOTAL DEMAND RESPONSE Peak Reduction (MW)	
Year	I&M	AEP-East*	I&M	AEP-East*	I&M	AEP-East*	I&M	AEP-East*
2014	**240**	445	**56**	132	**59**	271	**355**	849
2015	**240**	445	**56**	179	**92**	439	**388**	1,063
2016	**240**	445	**56**	224	**121**	585	**417**	1,255
2017	**240**	445	**56**	250	**143**	654	**439**	1,350
2018	**240**	445	**56**	252	**163**	714	**459**	1,411
2019	**240**	445	**56**	253	**180**	808	**476**	1,506
2020	**240**	445	**56**	255	**194**	924	**490**	1,624
2021	**240**	445	**56**	255	**205**	1,019	**501**	1,719
2022	**240**	445	**56**	255	**214**	1,093	**510**	1,793
2023	**240**	445	**56**	255	**220**	1,150	**516**	1,850
2024	**240**	445	**56**	255	**224**	1,192	**520**	1,892
2025	**240**	445	**56**	255	**227**	1,228	**523**	1,928
2026	**240**	445	**56**	255	**228**	1,251	**524**	1,951
2027	**240**	445	**56**	255	**228**	1,265	**524**	1,965
2028	**240**	445	**56**	255	**227**	1,271	**523**	1,971
2029	**240**	445	**56**	255	**228**	1,275	**524**	1,975
2030	**240**	445	**56**	255	**228**	1,277	**524**	1,977
2031	**240**	445	**56**	255	**228**	1,277	**524**	1,977
2032	**240**	445	**56**	255	**227**	1,275	**523**	1,975
2033	**240**	445	**56**	255	**228**	1,278	**524**	1,978

	(PROJECTED) CUMULATIVE ENERGY EFFICIENCY (GWh)	
Year	I&M	AEP-East*
2014	**383**	2,051
2015	**549**	2,761
2016	**693**	3,322
2017	**827**	3,735
2018	**947**	4,091
2019	**1,053**	4,640
2020	**1,140**	5,324
2021	**1,210**	5,863
2022	**1,266**	6,301
2023	**1,307**	6,651
2024	**1,337**	6,923
2025	**1,356**	7,126
2026	**1,366**	7,272
2027	**1,370**	7,368
2028	**1,370**	7,426
2029	**1,370**	7,457
2030	**1,370**	7,472
2031	**1,370**	7,475
2032	**1,370**	7,475
2033	**1,370**	7,475

Reflects forecasted DR and EE levels embedded into the Company's July-2013 load & peak demand forecast… This would exclude incremental levels of such resources that would result from the Rockport Unit 1 disposition evaluation performed.

* AEP-East includes Ohio-Wires customers and the prescribed EE reductions through 2025 under Ohio SB 221.

H. SUMMARY: I&M's "GOING-IN" future PJM annual capacity positions

Assuming that the I&M LSE was viewed individually as part of a PJM-planning perspective, the following **Table 1-4** offers a long-term (20-year) overview of such an I&M "stand-alone" capacity position within PJM though the 2033/34 PJM planning year. This view effectively assumes that the Company would continue to elect to participate in the PJM-RPM as an FRR (*i.e.*, self-planning) entity as opposed to participating in PJM's capacity auction construct. Further it assumes, as a "going-in"—or base assumption—that Rockport Unit 1 (and Unit 2) would continue to contribute ICAP throughout the planning horizon. As reflected in the Table 1-3 column identified as "Net Position w/ New Capacity" (col. 20), I&M would be "long" capacity by 156 MW beginning with the next (2018/19) 3-year forward PJM-RPM Base Residual Auction planning year.[9] This demonstrates and confirms that, not surprisingly, I&M would be *significantly* exposed—from a stand-alone planning perspective—should a Rockport Unit 1 disposition strategy call for the retirement of this unit.

In summary, based on the recommendations set forth in this testimony and, again, assuming that the I&M LSE were viewed individually as part of a PJM-planning perspective, Table 1-4 offers an overview of such an I&M stand-alone capacity position within PJM assuming the Company would continue to elect to be an FRR planning entity. It offers a "going-in" I&M capacity position profile over the next 20 years—*i.e.,* **before** the addition of incremental Plexos® model-selected resources—that reflects, <u>in addition to the recommended December 2017 "Rockport Unit 1 SCR Project" retrofit</u>, the:

- continued advancement of significant demand reduction (see Table 1-2);
- additional 200-MW (nameplate) of wind resources by 2015 (Headwaters Wind Farm expected to be in-service by December 2014);
- retirement of Tanners Creek Units 1-4 effective June 2015;
- ultimate retrofit of Rockport Unit 1 with DFGD by December 2025; and
- ultimate retrofit of Rockport Unit 2 with SCR and DFGD by December 2019 and December 2028, respectively.

[9] Stated another way, I&M would have 156 MW of capacity resources above the (minimum) PJM-FRR Installed Reserve Margin criterion of 15.7 percent.

Table 1-4 "Going-In" Capacity Position

INDIANA MICHIGAN POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (July 2013) Load Forecast
(2014/2015 - 2033/2034)
2013 (Going-In; ie., No Resource Additions)

		Obligation to PJM										Resources									I&M Position (MW)		PJM Reserve Margin			
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)		(19)	(20)				
					=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)						=(11)-(12) + Sum(14) +(15)		=(16)*(1-(17))		=((11)-(12) +(15)) *(1-(17)) -(10)	=(18)-(10)				
Planning Year		Internal Demand (a)	DSM (b)	Projected DSM Impact (c)	Net Internal Demand	Interruptible Demand Response (d)	Demand Response Factor	Forecast Pool Req't (e)	UCAP Obligation	Net UCAP Market Obligation (f)	Total UCAP Obligation	Existing Capacity & Planned Changes (g)	Net Capacity Sales (h)	Planned Capacity Additions Units	Planned Capacity Additions MW (i)	Annual Purchases	Net ICAP	AEP EFORd (j)	Available UCAP		Net Position w/o New Capacity	Net Position w/ New Capacity	Total UCAP Obligation Less IDR and IRM	Installed Reserve Margin (IRM)	I&M Reserve Margin Above PJM IRM	Total I&M Reserve Margin
2014 /15	(k)	4,133	(59)	0	4,133	296	0.954	1.093	4,208	0	4,208	5,479	0				5,479	5.90%	5,156		948	948	3,887	16.20%	24.39%	40.59%
2015 /16	(k)	4,150	(92)	(8)	4,142	296	0.954	1.092	4,215	0	4,215	4,497	0	200 MW Wind	26	0	4,523	5.29%	4,284		44	69	3,910	15.70%	1.76%	17.46%
2016 /17	(k)	4,160	(121)	(20)	4,140	296	0.953	1.092	4,212	0	4,212	4,497	0				4,523	5.29%	4,284		47	72	3,907	15.70%	1.84%	17.54%
2017 /18	(k)	4,171	(143)	(31)	4,140	296	0.953	1.092	4,211	0	4,211	4,547	(56)				4,629	5.22%	4,387		152	176	3,906	15.70%	4.51%	20.21%
2018 /19		4,243	(163)	(59)	4,183	296	0.953	1.092	4,259	0	4,259	4,577	(55)				4,658	5.22%	4,415		131	156	3,947	15.70%	3.95%	19.65%
2019 /20		4,256	(180)	(92)	4,164	296	0.953	1.092	4,238	0	4,238	4,577	(60)				4,663	5.22%	4,420		157	182	3,929	15.70%	4.63%	20.33%
2020 /21		4,264	(194)	(121)	4,143	296	0.953	1.092	4,215	0	4,215	4,608	(57)				4,691	5.23%	4,446		206	231	3,909	15.70%	5.91%	21.61%
2021 /22		4,297	(205)	(143)	4,153	296	0.953	1.092	4,226	0	4,226	4,608	(45)				4,679	5.23%	4,434		184	208	3,919	15.70%	5.31%	21.01%
2022 /23		4,320	(214)	(163)	4,157	296	0.953	1.092	4,230	0	4,230	4,608	(32)				4,666	5.23%	4,422		167	192	3,922	15.70%	4.90%	20.60%
2023 /24		4,341	(220)	(180)	4,161	296	0.953	1.092	4,234	0	4,234	4,608	0				4,634	5.23%	4,392		133	158	3,926	15.70%	4.02%	19.72%
2024 /25		4,352	(224)	(194)	4,158	296	0.953	1.092	4,231	0	4,231	4,608	0				4,634	5.23%	4,392		136	161	3,923	15.70%	4.10%	19.80%
2025 /26		4,388	(227)	(205)	4,182	296	0.953	1.092	4,257	0	4,257	4,593	0				4,619	5.22%	4,378		96	121	3,945	15.70%	3.07%	18.77%
2026 /27		4,411	(228)	(214)	4,197	296	0.953	1.092	4,274	0	4,274	4,593	0				4,619	5.22%	4,378		79	104	3,960	15.70%	2.63%	18.33%
2027 /28		4,437	(228)	(220)	4,216	296	0.953	1.092	4,295	0	4,295	4,593	0				4,619	5.22%	4,378		58	83	3,978	15.70%	2.09%	17.79%
2028 /29		4,455	(227)	(224)	4,232	296	0.953	1.092	4,311	0	4,311	4,577	0				4,603	5.22%	4,363		27	52	3,992	15.70%	1.30%	17.00%
2029 /30		4,491	(228)	(227)	4,264	296	0.953	1.092	4,347	0	4,347	4,577	0				4,603	5.22%	4,363		(9)	16	4,023	15.70%	0.40%	16.10%
2030 /31		4,519	(228)	(228)	4,291	296	0.953	1.092	4,377	0	4,377	4,577	0				4,603	5.22%	4,363		(39)	(14)	4,049	15.70%	-0.35%	15.35%
2031 /32		4,548	(228)	(228)	4,320	296	0.953	1.092	4,408	0	4,408	4,577	0				4,603	5.22%	4,363		(70)	(45)	4,076	15.70%	-1.10%	14.60%
2032 /33		4,563	(227)	(227)	4,336	296	0.953	1.092	4,425	0	4,425	4,577	0				4,603	5.22%	4,363		(87)	(62)	4,091	15.70%	-1.52%	14.18%
2033 /34		4,602	(228)	(228)	4,374	296	0.953	1.092	4,467	0	4,467	4,577	0				4,603	5.22%	4,363		(129)	(104)	4,127	15.70%	-2.52%	13.18%

Notes:

(a) Based on (July 2013) Load Forecast (with implied PJM diversity factor)

(b) Existing plus approved and projected "Passive" EE, and VVO
(note: these values & timing are for reference only and are not reflected in position determination)

(c) For PJM planning purposes, the ultimate impact of new DSM is 'delayed' ~4 years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process

(d) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR

(e) Installed Reserve Margin (IRM) = 16.2%(2014), 15.7%(2015-2033)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes company MLR share of:
FRR view of obligations only

(g) Reflects the members ownership ratio of following summer capability assumptions:
I&M share of AEP's OVEC capacity entitlment (AEP entitlement = 43.47% PPR-share)
Wind Farm PPAs (Where Applicable)

(g) continued
EFFICIENCY IMPROVEMENTS:
2018/19: Rockport 1: 36 MW (turbine)
2017/18: Cook 2: 50 MW (turbine)
2020/21: Rockport 2: 36 MW (turbine)
FGD DERATES:
2025/26: Rockport 1: (18) MW
2028/29: Rockport 2: (18) MW
DSI DERATES:
2014/15: Rockport 1-2: 0 MW each
RETIREMENTS:
2015/16: Tanners Ck. 1-4

(h) Includes:
Estimated I&M nominations for PJM EE ('passive' DR program) levels
--reflected as a UCAP '<resource>'-- as part of PJM's emerging auction products

(i) New wind and solar capacity value is assumed to be 13% and 38% of nameplate

(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCapacity
as of twelve months ended 9/30 of the previous year

(k) Reflects PJM forecast of AEP Zonal demand -- Allocated to I&M based on 5CP

Summary of Long-Term Commodity Price Forecast Scenarios Used in Plexos® Modeling

(Source: AEP Fundamental Analysis, August 2013)

Unless otherwise note, all Annual-Average pricing is represented in 'Nominal' Dollars

NATURAL GAS (Henry Hub) ($/MMBtu)

	'BASE' Fleet Transition (1H2013) Carbon in 2022	"Fleet Transition (1H2013)" Alternative Scenarios: HIGHER Band Carbon in 2022	LOWER Band Carbon in 2022	No CO_2	High CO_2
2013	4.04	4.06	4.06	4.06	4.06
2014	5.05	5.25	4.85	5.04	5.07
2015	5.47	5.91	5.14	5.45	5.49
2016	5.83	6.71	5.13	5.81	5.85
2017	6.01	6.91	5.29	5.99	6.03
2018	6.12	7.04	5.39	6.10	6.14
2019	6.19	7.12	5.45	6.17	6.21
2020	6.43	7.40	5.66	6.41	6.45
2021	6.75	7.77	5.94	6.62	6.77
2022	7.18	8.26	6.32	6.81	7.32
2023	7.30	8.40	6.43	7.00	7.45
2024	7.51	8.63	6.61	7.19	7.66
2025	7.75	8.91	6.82	7.40	7.90
2026	7.85	9.03	6.91	7.61	8.01
2027	8.04	9.25	7.08	7.80	8.20
2028	8.22	9.45	7.23	7.97	8.39
2029	8.41	9.67	7.40	8.15	8.57
2030	8.52	9.80	7.50	8.27	8.69
2031	8.73	10.04	7.68	8.47	8.91
2032	8.94	10.28	7.87	8.67	9.12
2033	9.16	10.54	8.06	8.89	9.34
2034	9.39	10.80	8.26	9.11	9.58
2035	9.61	11.05	8.46	9.32	9.80

CO2 ($/Metric Tonne)

	'BASE' Fleet Transition (1H2013) Carbon in 2022	"Fleet Transition (1H2013)" Alternative Scenarios: HIGHER Band Carbon in 2022	LOWER Band Carbon in 2022	No CO_2	High CO_2 Carbon in 2022
2013	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00
2022	15.08	15.08	15.08	0.00	25.00
2023	15.28	15.28	15.28	0.00	25.32
2024	15.48	15.48	15.48	0.00	25.65
2025	15.67	15.67	15.67	0.00	25.99
2026	15.88	15.88	15.88	0.00	26.32
2027	16.08	16.08	16.08	0.00	26.66
2028	16.29	16.29	16.29	0.00	27.02
2029	16.50	16.50	16.50	0.00	27.37
2030	16.72	16.72	16.72	0.00	27.72
2031	16.94	16.94	16.94	0.00	28.09
2032	17.16	17.16	17.16	0.00	28.45
2033	17.38	17.38	17.38	0.00	28.81
2034	17.60	17.60	17.60	0.00	29.19
2035	17.84	17.84	17.84	0.00	29.57

Coal-Illinois Basin (~4.3#) ($/Ton-FOB Mine)

	'BASE' Fleet Transition (1H2013) Carbon in 2022	"Fleet Transition (1H2013)" Alternative Scenarios: HIGHER Band Carbon in 2022	LOWER Band Carbon in 2022	No CO_2	High CO_2 Carbon in 2022
2013	49.45	57.86	43.52	48.00	49.45
2014	51.45	60.20	45.28	50.00	50.68
2015	53.45	62.54	47.04	52.00	52.65
2016	53.15	62.19	46.78	51.70	52.36
2017	53.95	63.13	47.48	52.50	53.15
2018	56.91	66.58	50.08	55.45	56.06
2019	60.65	70.96	53.37	59.18	59.74
2020	63.42	74.20	55.81	61.95	62.47
2021	63.56	74.37	55.94	62.10	62.61
2022	65.01	76.06	57.21	63.54	60.78
2023	67.85	79.38	59.70	66.38	63.44
2024	68.04	79.61	59.88	66.57	63.62
2025	68.27	79.88	60.08	66.80	63.83
2026	68.37	79.99	60.17	66.90	63.93
2027	68.47	80.11	60.25	67.00	64.02
2028	68.07	79.64	59.90	66.60	63.64
2029	68.57	80.23	60.34	67.10	64.11
2030	69.57	81.40	61.22	68.10	65.05
2031	69.77	81.63	61.40	68.30	65.24
2032	71.57	83.74	62.98	70.10	66.92
2033	73.82	86.37	64.96	72.35	69.02
2034	77.82	91.05	68.48	76.34	72.76
2035	80.81	94.55	71.11	79.33	75.56

Coal-PRB (~0.8#, 8400 Btu) ($/Ton-FOB Mine)

	'BASE' Fleet Transition (1H2013) Carbon in 2022	"Fleet Transition (1H2013)" Alternative Scenarios: HIGHER Band Carbon in 2022	LOWER Band Carbon in 2022	No CO_2	High CO_2 Carbon in 2022
2013	10.10	11.82	8.89	10.10	10.10
2014	10.70	12.52	9.42	10.78	10.54
2015	11.35	13.28	9.99	11.44	11.18
2016	11.35	13.28	9.99	11.44	11.18
2017	11.75	13.75	10.34	11.84	11.57
2018	11.96	13.99	10.52	12.05	11.78
2019	12.45	14.57	10.96	12.54	12.26
2020	13.23	15.48	11.64	13.33	13.03
2021	13.19	15.43	11.61	13.29	12.99
2022	13.96	16.33	12.28	14.24	13.05
2023	14.49	16.95	12.75	14.78	13.55
2024	14.29	16.72	12.58	14.58	13.36
2025	14.24	16.66	12.53	14.52	13.31
2026	14.45	16.91	12.72	14.74	13.51
2027	14.62	17.11	12.87	14.91	13.67
2028	15.10	17.67	13.29	15.40	14.12
2029	15.42	18.04	13.57	15.73	14.42
2030	17.28	20.22	15.21	17.63	16.16
2031	19.54	22.86	17.20	19.93	18.27
2032	23.24	27.19	20.45	23.70	21.73
2033	26.38	30.86	23.21	26.91	24.67
2034	29.39	34.39	25.86	29.98	27.48
2035	28.78	33.67	25.33	29.36	26.91

NATURAL GAS (Henry Hub) (REAL, 2011 $) ($/MMBtu)

	'BASE' Fleet Transition (1H2013) Carbon in 2022	"Fleet Transition (1H2013)" Alternative Scenarios: HIGHER Band Carbon in 2022	LOWER Band Carbon in 2022	No CO_2	High CO_2
2013	3.84	3.85	3.85	3.85	3.85
2014	4.70	4.89	4.51	4.68	4.71
2015	4.97	5.36	4.67	4.95	4.98
2016	5.16	5.93	4.54	5.14	5.17
2017	5.19	5.97	4.57	5.17	5.20
2018	5.16	5.94	4.54	5.15	5.18
2019	5.11	5.87	4.49	5.09	5.12
2020	5.18	5.96	4.56	5.17	5.20
2021	5.33	6.13	4.69	5.22	5.34
2022	5.54	6.37	4.87	5.25	5.65
2023	5.51	6.33	4.85	5.28	5.62
2024	5.54	6.37	4.88	5.31	5.65
2025	5.60	6.43	4.92	5.35	5.71
2026	5.55	6.38	4.88	5.38	5.66
2027	5.56	6.40	4.89	5.39	5.67
2028	5.57	6.40	4.90	5.40	5.68
2029	5.58	6.41	4.91	5.41	5.69
2030	5.54	6.37	4.87	5.37	5.65
2031	5.56	6.39	4.89	5.39	5.67
2032	5.57	6.41	4.90	5.41	5.68
2033	5.59	6.43	4.92	5.42	5.70
2034	5.62	6.46	4.94	5.45	5.73
2035	5.63	6.47	4.95	5.46	5.74

ON-Peak Energy (PJM-AEP Gen Hub) ($/Mwh)

	'BASE' Fleet Transition (1H2013) Carbon in 2022	"Fleet Transition (1H2013)" Alternative Scenarios: HIGHER Band Carbon in 2022	LOWER Band Carbon in 2022	No CO_2	High CO_2 Carbon in 2022
2013	34.37	38.00	33.68	35.39	34.87
2014	37.94	41.19	35.87	39.64	37.68
2015	48.38	51.47	44.99	48.80	47.26
2016	55.92	62.39	50.47	56.71	55.94
2017	58.33	64.09	52.96	58.80	57.73
2018	59.02	64.85	53.72	59.81	58.51
2019	59.69	65.75	54.28	60.57	59.62
2020	61.51	67.23	55.91	62.60	61.57
2021	64.04	70.33	58.17	64.30	64.11
2022	72.74	79.19	67.79	65.87	78.00
2023	74.33	80.92	68.93	67.40	79.66
2024	75.87	82.87	70.34	69.20	81.20
2025	77.51	84.94	71.69	70.76	82.56
2026	78.86	86.31	72.55	71.98	83.81
2027	80.60	88.46	74.52	74.18	85.89
2028	81.99	90.44	76.03	75.16	87.26
2029	83.65	91.87	76.92	77.03	89.01
2030	84.41	92.53	78.73	78.16	89.91
2031	86.04	94.97	80.62	79.73	91.90
2032	88.14	97.48	82.61	81.36	93.48
2033	90.15	99.73	84.21	83.42	95.92
2034	88.94	98.01	83.87	81.97	93.64
2035	91.25	101.27	86.36	84.28	96.59

OFF-Peak Energy (PJM-AEP Gen Hub) ($/Mwh)

	'BASE' Fleet Transition (1H2013) Carbon in 2022	"Fleet Transition (1H2013)" Alternative Scenarios: HIGHER Band Carbon in 2022	LOWER Band Carbon in 2022	No CO_2	High CO_2 Carbon in 2022
2013	23.40	25.28	22.03	23.45	23.39
2014	24.50	26.51	22.78	25.06	24.20
2015	28.52	30.60	26.28	29.29	27.89
2016	34.10	37.00	30.70	34.89	33.28
2017	37.38	41.18	33.53	38.62	36.93
2018	38.37	42.54	34.32	39.60	37.97
2019	39.25	43.88	34.97	40.61	38.94
2020	40.76	45.46	36.37	42.24	40.52
2021	42.25	47.47	37.44	43.44	41.98
2022	53.89	59.16	49.77	44.64	60.11
2023	54.86	60.50	49.96	46.13	61.53
2024	56.20	61.71	51.69	47.10	62.49
2025	57.24	63.25	51.97	48.21	63.95
2026	58.16	64.16	52.27	49.26	65.14
2027	59.05	65.42	53.31	50.52	66.18
2028	60.20	66.93	54.13	51.55	66.78
2029	61.45	68.33	54.90	52.75	68.42
2030	62.69	69.66	55.97	53.84	69.32
2031	64.20	71.51	57.34	55.27	71.11
2032	66.16	74.14	59.03	57.29	72.83
2033	68.50	76.63	60.92	59.51	75.04
2034	70.00	78.64	62.65	61.00	76.41
2035	71.70	80.68	63.91	62.80	78.34

Capacity Value (PJM-RTO RPM) ($/MW-Day)

	'BASE' Fleet Transition (1H2013) Carbon in 2022	"Fleet Transition (1H2013)" Alternative Scenarios: HIGHER Band Carbon in 2022	LOWER Band Carbon in 2022	No CO_2	High CO_2 Carbon in 2022
2013	23.03	23.03	23.03	23.03	23.03 *
2014	85.05	85.05	85.05	85.05	85.05 *
2015	131.61	131.61	131.61	131.83	131.83 *
2016	91.30	91.30	91.30	91.30	91.30 *
2017	132.49	148.30	146.90	146.57	127.11
2018	199.74	226.24	224.35	223.67	188.69
2019	215.54	241.43	240.06	239.28	202.58
2020	231.74	256.95	256.13	255.23	216.81
2021	248.55	273.03	272.80	271.78	231.55
2022	265.99	289.70	290.07	288.92	246.85
2023	284.08	306.97	307.97	306.69	262.70
2024	302.83	324.86	326.51	325.10	279.13
2025	321.95	343.05	345.39	343.84	295.87
2026	341.74	361.86	364.91	363.22	313.19
2027	362.23	378.78	378.78	378.78	331.10
2028	383.42	386.73	386.73	386.73	349.63
2029	394.85	394.85	394.85	394.85	368.79
2030	403.15	403.15	403.15	403.15	388.61
2031	411.61	411.61	411.61	411.61	409.09
2032	420.26	420.26	420.26	420.26	420.26
2033	429.08	429.08	429.08	429.08	429.08
2034	438.09	438.09	438.09	438.09	438.09
2035	447.29	447.29	447.29	447.29	447.29

* Represents actual cleared forward PJM-RTO Base Residual Auction UCAP clearing prices for those respective XXXX/(XXXX+1) forward PJM Planning Years (represented on a wtd "calendar year" basis).

Summary of Major Cost & Performance Paramenters Used in Plexos® Modeling

(All Cost Estimates reflected in 'Nominal' $)

Rockport Unit 1...

	Rockport U1 (Total Unit, 1320 MW)													Rockport U1 (I&M Cost-Based Share [@85%])			
	Performance Parameter							*Cost Parameter*									
									Consumables								
	Unit Capability		Heat Rate	Avg.	Emission Rates			Delivered	Sodium	Activated	Anhydrous	Lime	Other	FOM		On-Going Capital*	
	Max	Min	-Avg Annual-	Availability	SO_2	NO_x	Hg	Fuel Cost	Bicarb (DSI)	Carbon (ACI)	Ammonia (SCR)	(DFGD)	VOM	*If Retired*	*If Retrofit*	*If Retired*	*If Retrofit*
	(MW)	(MW)	(Btu/kWh)	(%)	(lb/MMBtu)	(lb/MMBtu)	(lb/Trillion Btu)	($/MMBtu)	($/ton)	($/ton)	($/ton)	($/ton)	($/Mwh)	($000)	($000)	($000)	($000)
2014	1,320	500	[redacted]	[redacted]	0.87	-	2.90	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.99	11,258	11,258	7,845	10,460
2015	1,320	500	[redacted]	[redacted]	0.32	-	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.01	19,400	19,400	8,001	16,001
2016	1,320	500	[redacted]	[redacted]	0.32	-	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.04	7,771	7,771	5,220	20,881
2017	1,320	500	[redacted]	[redacted]	0.32	-	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.06	15,606	15,606	0	41,554
2018	1,356	550	[redacted]	[redacted]	0.32	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.18	-	8,231	-	36,994
2019	1,356	650	[redacted]	[redacted]	0.32	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.20	-	7,093	-	20,360
2020	1,356	650	[redacted]	[redacted]	0.33	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.23	-	18,005	-	11,626
2021	1,356	650	[redacted]	[redacted]	0.33	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.25	-	11,046	-	43,008
2022	1,356	650	[redacted]	[redacted]	0.33	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.28	-	17,921	-	15,142
2023	1,356	650	[redacted]	[redacted]	0.33	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.31	-	10,950	-	529
2024	1,356	650	[redacted]	[redacted]	0.33	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.33	-	13,295	-	18,133
2025	1,356	650	[redacted]	[redacted]	0.33	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.35	-	13,682	-	18,586
2026	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.54	-	10,318	-	19,051
2027	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.56	-	10,520	-	19,527
2028	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.58	-	10,620	-	20,015
2029	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.61	-	11,300	-	20,516
2030	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.63	-	11,809	-	21,029
2031	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.65	-	12,095	-	21,554
2032	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.67	-	12,514	-	22,093
2033	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.70	-	12,964	-	22,645
2034	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.72	-	13,870	-	23,212
2035	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.74	-	14,633	-	23,792
2036	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.77	-	15,103	-	24,387
2037	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.79	-	15,662	-	24,996
2038	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.81	-	16,535	-	25,621
2039	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.84	-	17,112	-	26,262
2040	1,338	650	[redacted]	[redacted]	0.12	0.15	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.86	-	17,415	-	26,918

Rockport Unit 2...

	Rockport U2 (Total Unit, 1300 MW)													Rockport U2 (I&M Cost-Based Share [@85%])			
	Performance Parameter							*Cost Parameter*									
									Consumables								
	Unit Capability		Heat Rate	Avg.	Emission Rates			Delivered	Sodium	Activated	Anhydrous	Lime	Other				On-Going
	Max	Min	-Avg Annual-	Availability	SO_2	NO_x	Hg	Fuel Cost	Bicarb (DSI)	Carbon (ACI)	Ammonia (SCR)	(DFGD)	VOM		FOM		Capital*
	(MW)	(MW)	(Btu/kWh)	(%)	(lb./MMBtu)	(lb./MMBtu)	(lb/Trillion Btu)	($/MMBtu)	($/ton)	($/ton)	($/ton)	($/ton)	($/Mwh)		($000)		($000)
2014	1,300	500	[redacted]	[redacted]	0.771	0.0	2.90	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.86		15,454		8,880
2015	1,300	500	[redacted]	[redacted]	0.325	0.0	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.88		8,712		4,010
2016	1,300	500	[redacted]	[redacted]	0.324	0.0	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.90		14,982		5,924
2017	1,300	500	[redacted]	[redacted]	0.325	0.0	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.92		7,708		24,919
2018	1,300	500	[redacted]	[redacted]	0.325	0.0	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.94		15,634		48,153
2019	1,300	650	[redacted]	[redacted]	0.325	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.96		16,429		41,575
2020	1,336	650	[redacted]	[redacted]	0.325	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.73		10,400		12,872
2021	1,336	650	[redacted]	[redacted]	0.325	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.74		16,962		63,424
2022	1,336	650	[redacted]	[redacted]	0.325	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.76		10,759		24,364
2023	1,336	650	[redacted]	[redacted]	0.325	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.78		17,581		15,401
2024	1,336	650	[redacted]	[redacted]	0.326	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.79		14,379		19,883
2025	1,336	650	[redacted]	[redacted]	0.326	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.80		14,800		20,380
2026	1,336	650	[redacted]	[redacted]	0.326	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.82		13,830		20,889
2027	1,336	650	[redacted]	[redacted]	0.326	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.83		14,195		21,411
2028	1,336	650	[redacted]	[redacted]	0.326	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.84		14,601		21,947
2029	1,318	650	[redacted]	[redacted]	0.115	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.02		12,528		22,495
2030	1,318	650	[redacted]	[redacted]	0.115	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.04		12,892		23,058
2031	1,318	650	[redacted]	[redacted]	0.115	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.05		13,414		23,634
2032	1,318	650	[redacted]	[redacted]	0.115	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.06		13,867		24,225
2033	1,318	650	[redacted]	[redacted]	0.115	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.08		14,326		24,831
2034	1,318	650	[redacted]	[redacted]	0.115	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.09		15,320		25,451
2035	1,318	650	[redacted]	[redacted]	0.115	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.11		16,015		26,088
2036	1,318	650	[redacted]	[redacted]	0.115	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.12		16,595		26,740
2037	1,318	650	[redacted]	[redacted]	0.115	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.13		17,046		27,408
2038	1,318	650	[redacted]	[redacted]	0.115	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.15		17,890		28,093
2039	1,318	650	[redacted]	[redacted]	0.115	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.16		18,535		28,796
2040	1,318	650	[redacted]	[redacted]	0.115	0.038	1.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.18		19,098		29,516

* Rockport unit 'On-Going Capital (OGC)' excludes major environmental capital expenditures highlighted on Weaver Direct Testimony, 'Table 2'

REDACTED
Exhibit SCW-3
Page 2 of 2

Summary of Major Cost & Performance Paramenters Used in Plexos® Modeling

(All Cost Estimates reflected in 'Nominal' $)

New-Build Natural Gas Alternatives...

Available In-Svc	New-Build CC (780 MW [906 MW w/ duct-firing], Mitsubishi 501GAC 2x2x1): Capability* Max (w/ Duct-Firing)	Capability* Nominal (w/o Duct-Firing)	Min	Avg. Avail.	(Nominal) Heat Rate -Avg Annual-	Fuel Cost @ 'TCO Pool' **	VOM	FOM	On-Going Capital***	New-Build SC-CT (164 MW, 2X GE 7EA): Capability (Per 2X 'Block') Max	Capability (Per 2X 'Block') Min	Heat Rate -Avg Annual-	Avg. Availability	Fuel Cost @ 'TCO Pool' **	VOM	FOM	On-Going Capital***	New-Build Internal Combustion Engines (201 MW, 22X Wartsila 20V34SG): Capability (Per 22X 'Block') Max	Capability (Per 22X 'Block') Min	Heat Rate -Avg Annual-	Fuel Cost @ 'TCO Pool' **	VOM	FOM	On-Going Capital***
Years	(MW)	(MW)	(MW)	(%)	(Btu/kWh)	($/MMBtu)	($/Mwh)	($/kW-Yr)	($/kW-Yr)	(MW)	(MW)	(Btu/kWh)	(%)	($/MMBtu)	($/Mwh)	($/kW-Yr)	($/kW-Yr)	(MW)	(MW)	(Btu/kWh)	($/MMBtu)	($/Mwh)	($/kW-Yr)	($/kW-Yr)
2014		-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
2015		-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
2016		-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
2017		-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
2018		-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
2019 Opt 2A	906	780	390	[redacted]	[redacted]	[redacted]	$3.06	$11.41	-	164	82	[redacted]	[redacted]	[redacted]	$9.80	$14.11	-	201	100	[redacted]	[redacted]	$7.02	$10.46	-
2020	906	780	390	[redacted]	[redacted]	[redacted]	$3.12	$11.63	-	164	82	[redacted]	[redacted]	[redacted]	$9.99	$14.39	-	201	100	[redacted]	[redacted]	$7.14	$10.66	-
2021	906	780	390	[redacted]	[redacted]	[redacted]	$3.17	$11.79	-	164	82	[redacted]	[redacted]	[redacted]	$10.13	$14.59	-	201	100	[redacted]	[redacted]	$7.26	$10.81	-
2022	906	780	390	[redacted]	[redacted]	[redacted]	$3.22	$11.99	-	164	82	[redacted]	[redacted]	[redacted]	$10.31	$14.84	-	201	100	[redacted]	[redacted]	$7.38	$10.99	-
2023	906	780	390	[redacted]	[redacted]	[redacted]	$3.27	$12.19	-	164	82	[redacted]	[redacted]	[redacted]	$10.47	$15.09	-	201	100	[redacted]	[redacted]	$7.51	$11.18	-
2024	906	780	390	[redacted]	[redacted]	[redacted]	$3.33	$12.43	-	164	82	[redacted]	[redacted]	[redacted]	$10.68	$15.38	-	201	100	[redacted]	[redacted]	$7.63	$11.39	-
2025 Opt 2B	906	780	390	[redacted]	[redacted]	[redacted]	$3.38	$12.59	-	164	82	[redacted]	[redacted]	[redacted]	$10.82	$15.58	-	201	100	[redacted]	[redacted]	$7.75	$11.55	-
2026	906	780	390	[redacted]	[redacted]	[redacted]	$3.44	$12.80	-	164	82	[redacted]	[redacted]	[redacted]	$11.00	$15.84	-	201	100	[redacted]	[redacted]	$7.88	$11.73	-
2027	906	780	390	[redacted]	[redacted]	[redacted]	$3.49	$13.01	-	164	82	[redacted]	[redacted]	[redacted]	$11.18	$16.09	-	201	100	[redacted]	[redacted]	$8.01	$11.92	-
2028	906	780	390	[redacted]	[redacted]	[redacted]	$3.55	$13.25	-	164	82	[redacted]	[redacted]	[redacted]	$11.39	$16.40	-	201	100	[redacted]	[redacted]	$8.14	$12.15	-
2029	906	780	390	[redacted]	[redacted]	[redacted]	$3.61	$13.43	-	164	82	[redacted]	[redacted]	[redacted]	$11.54	$16.62	-	201	100	[redacted]	[redacted]	$8.27	$12.31	-
2030	906	780	390	[redacted]	[redacted]	[redacted]	$3.67	$13.65	-	164	82	[redacted]	[redacted]	[redacted]	$11.73	$16.89	-	201	100	[redacted]	[redacted]	$8.40	$12.51	-
2031	906	780	390	[redacted]	[redacted]	[redacted]	$3.73	$13.87	-	164	82	[redacted]	[redacted]	[redacted]	$11.92	$17.17	-	201	100	[redacted]	[redacted]	$8.54	$12.72	-
2032	906	780	390	[redacted]	[redacted]	[redacted]	$3.79	$14.14	-	164	82	[redacted]	[redacted]	[redacted]	$12.15	$17.50	-	201	100	[redacted]	[redacted]	$8.68	$12.96	-
2033	906	780	390	[redacted]	[redacted]	[redacted]	$3.85	$14.33	-	164	82	[redacted]	[redacted]	[redacted]	$12.32	$17.74	-	201	100	[redacted]	[redacted]	$8.83	$13.14	-
2034	906	780	390	[redacted]	[redacted]	[redacted]	$3.91	$14.57	-	164	82	[redacted]	[redacted]	[redacted]	$12.51	$18.02	-	201	100	[redacted]	[redacted]	$8.97	$13.35	-
2035	906	780	390	[redacted]	[redacted]	[redacted]	$3.97	$14.80	-	164	82	[redacted]	[redacted]	[redacted]	$12.72	$18.31	-	201	100	[redacted]	[redacted]	$9.11	$13.57	-
2036	906	780	390	[redacted]	[redacted]	[redacted]	$4.04	$15.07	-	164	82	[redacted]	[redacted]	[redacted]	$12.95	$18.65	-	201	100	[redacted]	[redacted]	$9.26	$13.81	-
2037	906	780	390	[redacted]	[redacted]	[redacted]	$4.10	$15.25	-	164	82	[redacted]	[redacted]	[redacted]	$13.10	$18.87	-	201	100	[redacted]	[redacted]	$9.40	$13.98	-
2038	906	780	390	[redacted]	[redacted]	[redacted]	$4.16	$15.48	-	164	82	[redacted]	[redacted]	[redacted]	$13.30	$19.15	-	201	100	[redacted]	[redacted]	$9.54	$14.19	-
2039	906	780	390	[redacted]	[redacted]	[redacted]	$4.22	$15.70	-	164	82	[redacted]	[redacted]	[redacted]	$13.49	$19.43	-	201	100	[redacted]	[redacted]	$9.68	$14.39	-
2040	906	780	390	[redacted]	[redacted]	[redacted]	$4.28	$15.97	-	164	82	[redacted]	[redacted]	[redacted]	$13.72	$19.76	-	201	100	[redacted]	[redacted]	$9.82	$14.64	-

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* As a practical matter, due to poorer thermal efficiency/heat rate, duct-firing would be limited throughout the year. Therefore, for dispatch (energy) modeling purposes, a 'Nominal' rating --and (lower) attendant Heat Rate-- was utilized throughout the forecast period...
... However, Max "with duct-firing" Capability was recognized for purposes of determination of attributable PJM capacity (UCAP) value.

** Per 'BASE' pricing scenario.

*** 'On-Going Capital' expenditures are assumed to be incorporated into the Fixed O&M (FOM) estimates shown.

Indiana Michigan Power Co.
Rockport Unit 1 Disposition Analysis
Long-Term, Life Cycle Economics (2014-2040, with end-effects)

COMPARATIVE **Cumulative Present Worth (CPW) of I&M Net Utility "Generation" Costs (2014 $)**
(COST / <SAVINGS>)

$ Millions	**Option #2A** RETIRE & REPLACE RK U1 (12/2017), largely with PJM (Market) Capacity & Energy **through 2018**; then New-Build Resources (1/2019) *versus*	**Option #2B** RETIRE & REPLACE RK U1 (12/2017), largely with PJM (Market) Capacity & Energy **through 2024**; then New-Build Resources (1/2025) *versus*
	Option #1 RETROFIT Rockport Unit 1 with SCR (12/2017) *(then --for modeling purposes only-- assume NPDES/ELG/CCR & 316(b)-related equipment installed (total Plant) by 2019, and U1 DFGD and associated equipment installed by 12/2025)*	
L/T Commodity Pricing Scenarios		
BASE: **"BASE-Fleet Transition (1H2013)"**	**861**	**752**
% Change	*7.3%*	*6.4%*
Alternative Scenario Pricing...		
"LOWER Band"	**773**	**705**
% Change	*6.6%*	*6.0%*
"HIGHER Band"	**1,053**	**984**
% Change	*8.7%*	*8.1%*
"No CO_2 Price"	**1,153**	**1,064**
% Change	*10.7%*	*9.9%*
"High CO_2 Price"	**691**	**612**
% Change	*5.6%*	*5.0%*

Note:
Every $100 Million change in CPW is equivalent to a $0.52 per Mwh impact on levelized annual I&M G-revenue requirements (2014 dollars)

Additional Notes:
- o All scenario pricing alaternatives (excluding "No CO_2") assume carbon/CO_2 pricing is effective in 2022
- o Option #1 (RK U1 RETROFITTED) assumes investment recovery period for SCR (beg. 2018), and DFGD (beg. 2026), of 10 and 20-years, respectively.
- o Option #2 (RK U1 RETIRED & REPLACED w/ New-Build Resources) assumes a 30-year recovery period for any new-build (CC and/or CTs, ICs) in all analyses.
- o All cases assume TC1-4 retired 6/2015.
- o All cases reflect 200-MW (nameplate) of new wind resources effective 1/2015 (Headwaters Wind Facility).
- o Each Rockport unit reflects I&M's 50% (~650-MW) Ownership share; plus 70% (~455-MW) Purch.Entitlement from affiliate AEP Generating Cos.' 50% ownership share.
- o Option 2 cost profiles exclude costs associated w/ socio-economic impacts to the region.

Indiana Michigan Power Co.

Rockport Unit 1 Disposition Analysis

Long-Term, Life Cycle (Net) Utility Cost Evaluation

		Option 1			Option 2A			Option 2B		
	Alternative Pricing Scenario	I&M Load Cost ($000)	I&M Net Generation <Margin> ($000)	Grand Total, Net Utility Costs ($000)	I&M Load Cost ($000)	I&M Net Generation <Margin> ($000)	Grand Total, Net Utility Costs ($000)	I&M Load Cost ($000)	I&M Net Generation <Margin> ($000)	Grand Total, Net Utility Costs ($000)
A	Base	18,285,993	(6,481,012)	11,804,981	18,285,993	(5,619,611)	12,666,382	18,285,993	(5,728,796)	12,557,197
B	HIGHER Band	20,207,611	(8,124,817)	12,082,794	20,207,611	(7,071,753)	13,135,858	20,207,611	(7,140,994)	13,066,617
C	LOWER Band	16,920,016	(5,235,804)	11,684,212	16,920,016	(4,462,689)	12,457,327	16,920,016	(4,530,579)	12,389,437
D	No CO_2 Price	17,161,529	(6,366,442)	10,795,087	17,161,529	(5,213,322)	11,948,207	17,161,529	(5,302,426)	11,859,103
E	High CO_2 Price	19,149,937	(6,819,881)	12,330,056	19,149,937	(6,128,630)	13,021,307	19,149,937	(6,207,575)	12,942,362

		CHANGE versus 'Option #1'					
A	Base	0	861,401	**861,401**	0	752,216	**752,216**
B	HIGHER Band	0	1,053,064	**1,053,064**	0	983,823	**983,823**
C	LOWER Band	0	773,115	**773,115**	0	705,225	**705,225**
D	No CO_2 Price	0	1,153,120	**1,153,120**	0	1,064,016	**1,064,016**
E	High CO_2 Price	0	691,251	**691,251**	0	612,306	**612,306**

Exhibit SCW-4A

INDIANA MICHIGAN POWER COMPANY

Rockport Unit 1 Disposition Analysis

"Base" (Fleet Transition (1H2013)) Long-Term Commodity Price Forecast

	CPW ($000)			*CPW Savings vs. 'Option 1' ($000)*		
Disposition Alternative (1)	2014-2040 Optimization Period	End-Effects	Total Study Period	2014-2040 Optimization Period	End-Effects	Total Study Period
Option 1 (2)	8,074,330	3,730,651	**11,804,981**			-
Option 2A (3)	8,796,897	3,869,484	**12,666,382**	722,567	138,834	**861,400**
Option 2B (4)	8,668,458	3,888,739	**12,557,197**	594,128	158,088	**752,216**

Note:

(1) All cases assume Rockport 2 SCR installation in 1/1/2020 and FGD installation in 1/1/2029

(2) Option 1 assumes Rockport U1 SCR installation by 1/1/2018 and FGD installation by 1/1/2026

(3) Option 2A assumes Rockport U1 retired by 1/1/2018 w/ optimal replacement capacity --incl. CC-Build-- by 1/1/2019)

(4) *Same as 'Option 2A' except a replacement nat gas-build --in lieu of PJM market-- not an available replacement alternative until 1/1/2025)*

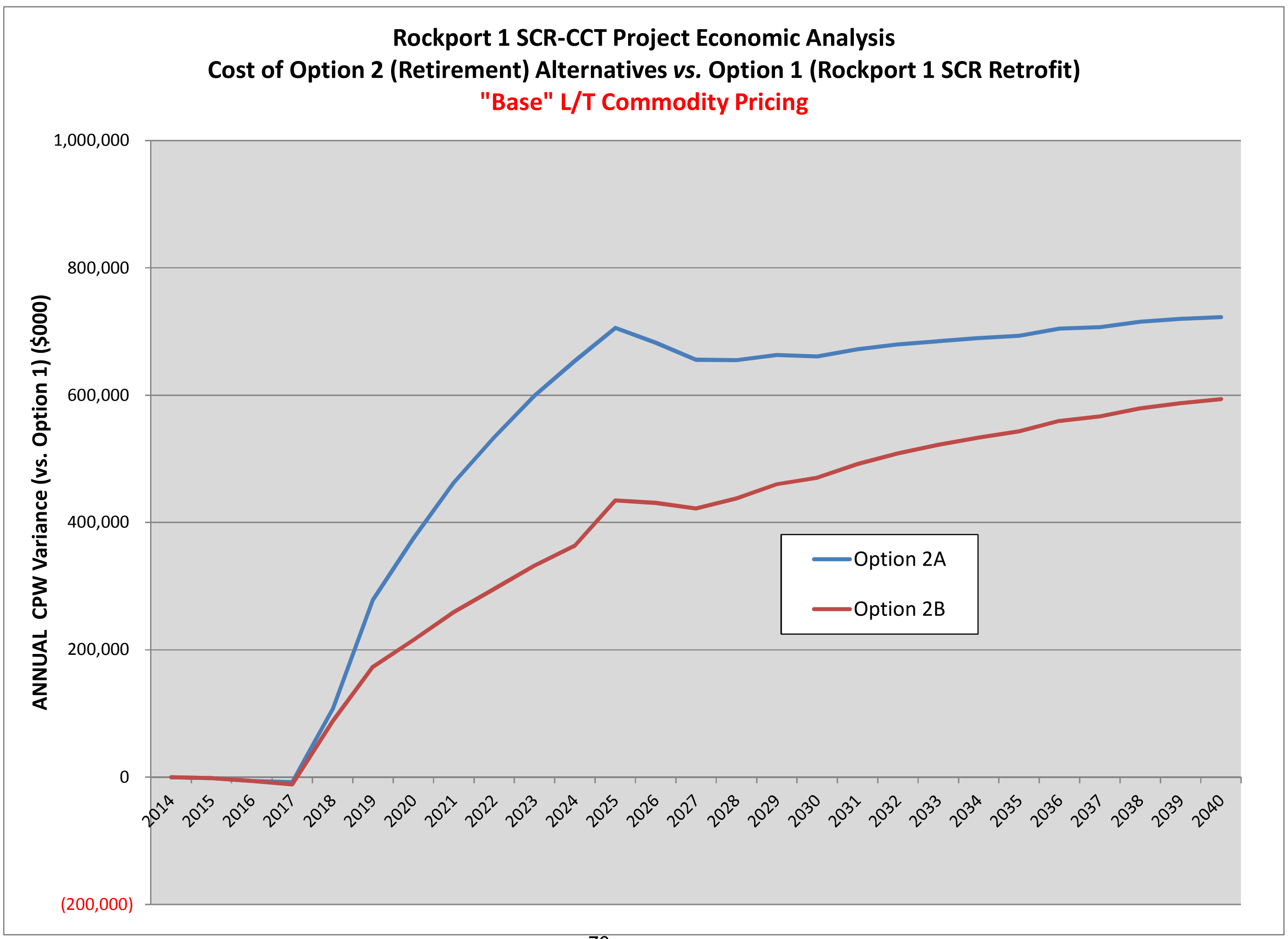


Exhibit SCW-4B

INDIANA MICHIGAN POWER COMPANY

Rockport Unit 1 Disposition Analysis

"HIGHER Band" Long-Term Commodity Price Forecast

Disposition Alternative (1)	CPW ($000) 2014-2040 Optimization Period	End-Effects	Total Study Period	*CPW Savings vs. 'Option 1' ($000)* 2014-2040 Optimization Period	End-Effects	Total Study Period
Option 1 (2)	8,102,298	3,980,496	**12,082,794**			-
Option 2A (3)	8,908,662	4,227,196	**13,135,858**	806,364	246,700	**1,053,064**
Option 2B (4)	8,821,907	4,244,710	**13,066,617**	719,609	264,214	**983,824**

Note:

(1) All cases assume Rockport 2 SCR installation by 1/1/2020 and FGD installation by 1/1/2029

(2) Option 1 assumes Rockport U1 SCR installation by 1/1/2018 and FGD installation by 1/1/2026

(3) Option 2A assumes Rockport U1 retired by 1/1/2018 w/ optimal replacement capacity --incl. CC-Build-- by 1/1/2019)

(4) *Same as 'Option 2A' except a replacement nat gas-build --in lieu of PJM market-- not an available replacement alternative until 1/1/2025)*

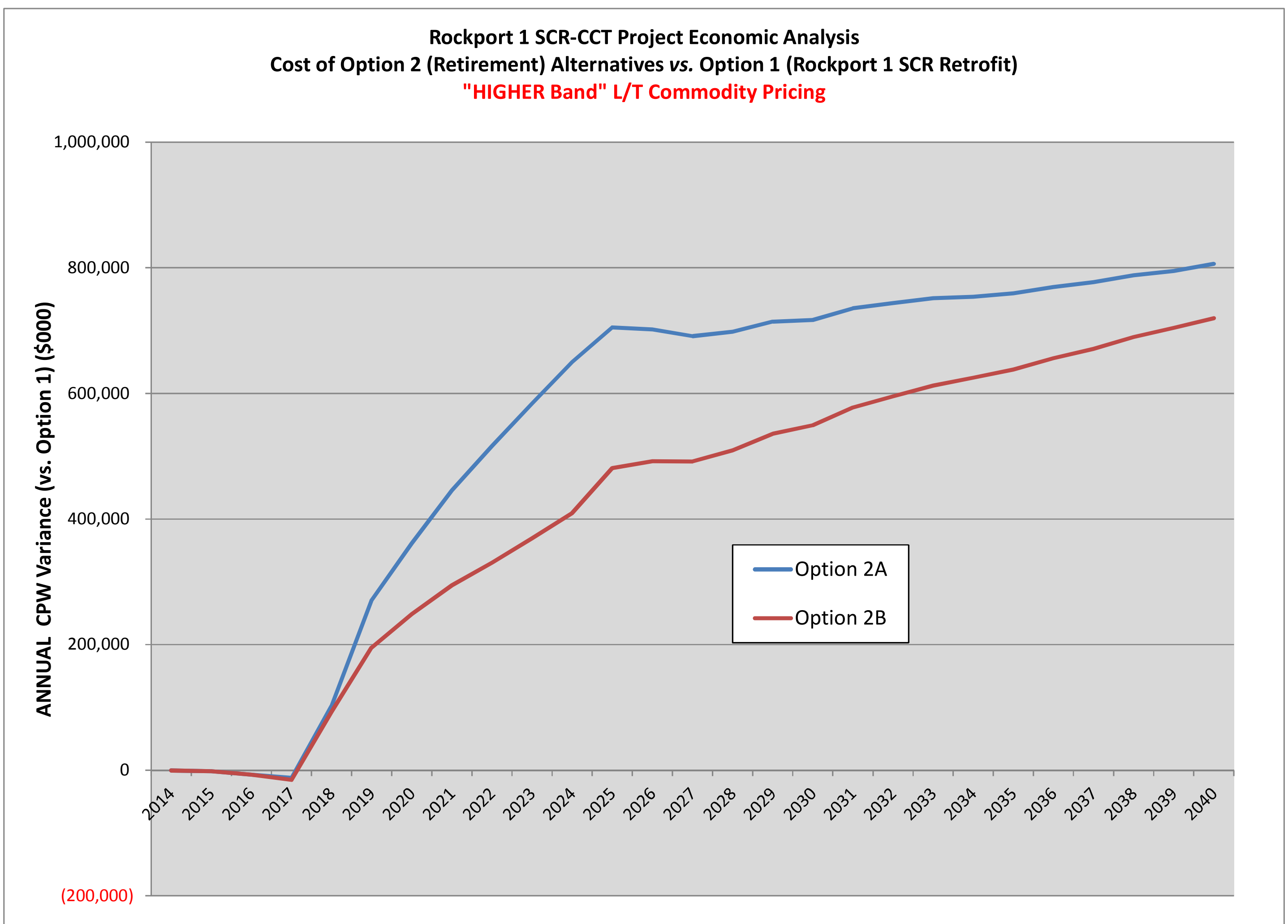


Exhibit SCW-4C

INDIANA MICHIGAN POWER COMPANY

Rockport Unit 1 Disposition Analysis

"LOWER Band" Long-Term Commodity Price Forecast

	CPW ($000)			*CPW Savings vs. 'Option 1' ($000)*		
Disposition Alternative (1)	2014-2040 Optimization Period	End-Effects	Total Study Period	2014-2040 Optimization Period	End-Effects	Total Study Period
Option 1 (2)	8,095,070	3,589,143	**11,684,212**			-
Option 2A (3)	8,744,671	3,712,656	**12,457,327**	649,601	123,513	**773,115**
Option 2B (4)	8,654,822	3,734,614	**12,389,437**	559,753	145,472	**705,224**

Note:

(1) All cases assume Rockport 2 SCR installation by 1/1/2020 and FGD installation by 1/1/2029

(2) Option 1 assumes Rockport U1 SCR installation by 1/1/2018 and FGD installation by 1/1/2026

(3) Option 2A assumes Rockport U1 retired by 1/1/2018 w/ optimal replacement capacity --incl. CC-Build-- by 1/1/2019)

(4) *Same as 'Option 2A' except a replacement nat gas-build --in lieu of PJM market-- not an available replacement alternative until 1/1/2025)*

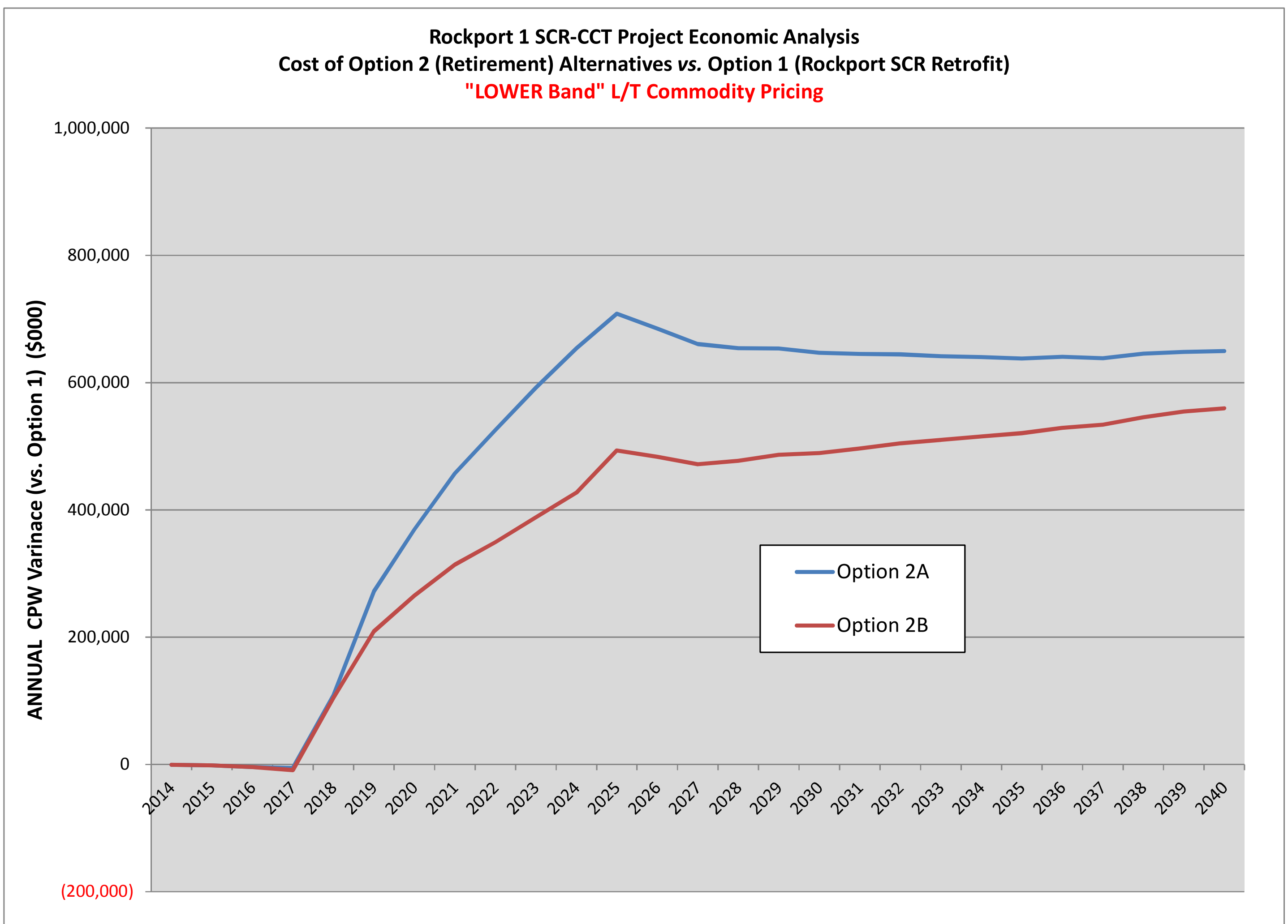


Exhibit SCW-4D

INDIANA MICHIGAN POWER COMPANY

Rockport Unit 1 Disposition Analysis

"No CO_2 Price" Long-Term Commodity Price Forecast

Disposition Alternative (1)	CPW ($000) 2014-2040 Optimization Period	CPW ($000) End-Effects	CPW ($000) Total Study Period	*CPW Savings vs. 'Option 1' ($000)* 2014-2040 Optimization Period	*CPW Savings vs. 'Option 1' ($000)* End-Effects	*CPW Savings vs. 'Option 1' ($000)* Total Study Period
Option 1 (2)	7,438,513	3,356,574	**10,795,087**			-
Option 2A (3)	8,374,937	3,573,270	**11,948,207**	936,423	216,696	**1,153,119**
Option 2B (4)	8,270,902	3,588,201	**11,859,103**	832,388	231,627	**1,064,016**

Note:

(1) All cases assume Rockport 2 SCR installation by 1/1/2020 and FGD installation by 1/1/2029

(2) Option 1 assumes Rockport U1 SCR installation by 1/1/2018 and FGD installation by 1/1/2026

(3) Option 2A assumes Rockport U1 retired by 1/1/2018 w/ optimal replacement capacity --incl. CC-Build-- by 1/1/2019)

(4) *Same as 'Option 2A' except a replacement nat gas-build --in lieu of PJM market-- not an available replacement alternative until 1/1/2025)*

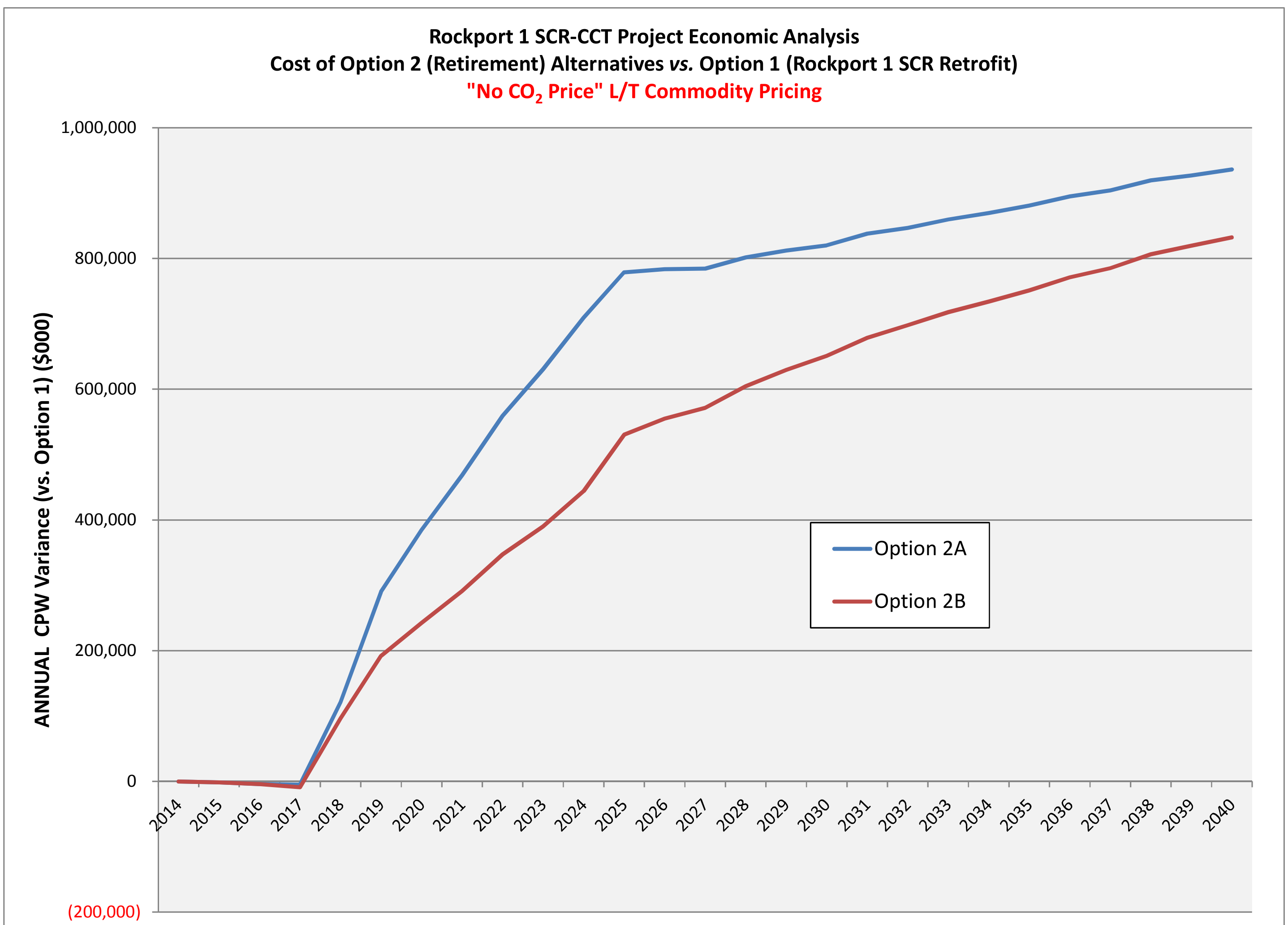


Exhibit SCW-4E

INDIANA MICHIGAN POWER COMPANY

Rockport Unit 1 Disposition Analysis

"High CO_2 Price" Long-Term Commodity Price Forecast

	CPW ($000)			*CPW Savings vs. 'Option 1' ($000)*		
Disposition Alternative (1)	2014-2040 Optimization Period	End-Effects	Total Study Period	2014-2040 Optimization Period	End-Effects	Total Study Period
Option 1 (2)	8,406,413	3,923,644	**12,330,056**			**-**
Option 2A (3)	8,958,700	4,062,607	**13,021,307**	552,288	138,963	**691,251**
Option 2B (4)	8,860,434	4,081,928	**12,942,362**	454,022	158,284	**612,305**

Note:

(1) All cases assume Rockport 2 SCR installation by 1/1/2020 and FGD installation by 1/1/2029

(2) Option 1 assumes Rockport U1 SCR installation by 1/1/2018 and FGD installation by 1/1/2026

(3) Option 2A assumes Rockport U1 retired by 1/1/2018 w/ optimal replacement capacity --incl. CC-Build-- by 1/1/2019)

(4) *Same as 'Option 2A' except a replacement nat gas-build --in lieu of PJM market-- not an available replacement alternative until 1/1/2025)*

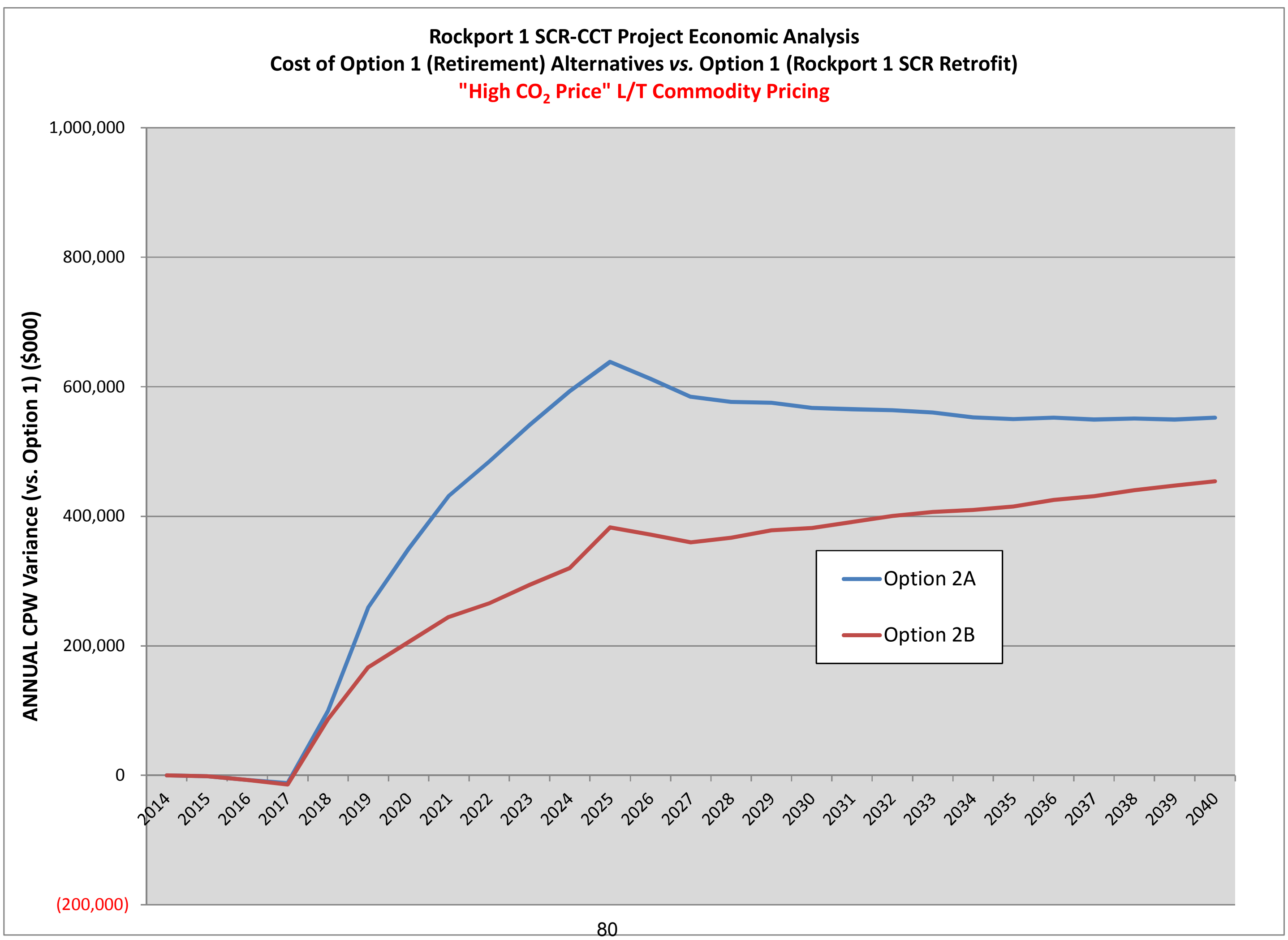


Exhibit JIF-4
OCC Cause No. PUD 201400229

Exhibit SCW-5
Page 1 of 2

Summary of Long-Term Commodity Price Forecast Scenarios Used in Plexos® Modeling

with an Additional Sensitivity Scenario for "Ultra High (Initially, $77/tonne)" CO_2 /Carbon Pricing

(Source: AEP Fundamental Analysis)

Unless otherwise note, all Annual-Average pricing is represented in 'Nominal' Dollars

NATURAL GAS (Henry Hub) ($/MMBtu)

	'BASE' Fleet Transition (1H2013) Carbon in 2022	"Fleet Transition (1H2013)" Alternative Scenarios: HIGHER Band Carbon in 2022	LOWER Band Carbon in 2022	No CO_2	High CO_2	Add'l Scenario: Ultra High CO_2	% CHANGE from "BASE CO_2" (~$15/tonne)
2014	5.05	5.25	4.85	5.04	5.07	4.99	-1.2%
2015	5.47	5.91	5.14	5.45	5.49	5.49	0.3%
2016	5.83	6.71	5.13	5.81	5.85	5.85	0.3%
2017	6.01	6.91	5.29	5.99	6.03	6.03	0.3%
2018	6.12	7.04	5.39	6.10	6.14	6.14	0.3%
2019	6.19	7.12	5.45	6.17	6.21	6.21	0.3%
2020	6.43	7.40	5.66	6.41	6.45	6.45	0.3%
2021	6.75	7.77	5.94	6.62	6.77	7.43	10.0%
2022	7.18	8.26	6.32	6.81	7.32	8.42	17.3%
2023	7.30	8.40	6.43	7.00	7.45	8.56	17.3%
2024	7.51	8.63	6.61	7.19	7.66	8.81	17.3%
2025	7.75	8.91	6.82	7.40	7.90	9.09	17.3%
2026	7.85	9.03	6.91	7.61	8.01	9.21	17.3%
2027	8.04	9.25	7.08	7.80	8.20	9.43	17.3%
2028	8.22	9.45	7.23	7.97	8.39	9.64	17.3%
2029	8.41	9.67	7.40	8.15	8.57	9.86	17.3%
2030	8.52	9.80	7.50	8.27	8.69	10.00	17.3%
2031	8.73	10.04	7.68	8.47	8.91	10.24	17.3%
2032	8.94	10.28	7.87	8.67	9.12	10.49	17.3%
2033	9.16	10.54	8.06	8.89	9.34	10.75	17.3%
2034	9.39	10.80	8.26	9.11	9.58	11.02	17.3%
2035	9.61	11.05	8.46	9.32	9.80	11.27	17.3%

CO2 ($/Metric Tonne)

	'BASE' Fleet Transition (1H2013) Carbon in 2022	"Fleet Transition (1H2013)" Alternative Scenarios: HIGHER Band Carbon in 2022	LOWER Band Carbon in 2022	No CO_2	High CO_2 Carbon in 2022	Add'l Scenario: Ultra High CO_2 Carbon in 2022	% CHANGE from "BASE CO_2" (~$15/tonne)
2014	0.00	0.00	0.00	0.00	0.00	0.00	
2015	0.00	0.00	0.00	0.00	0.00	0.00	
2016	0.00	0.00	0.00	0.00	0.00	0.00	
2017	0.00	0.00	0.00	0.00	0.00	0.00	
2018	0.00	0.00	0.00	0.00	0.00	0.00	
2019	0.00	0.00	0.00	0.00	0.00	0.00	
2020	0.00	0.00	0.00	0.00	0.00	0.00	
2021	0.00	0.00	0.00	0.00	0.00	0.00	
2022	15.08	15.08	15.08	0.00	25.00	77.16	411.7%
2023	15.28	15.28	15.28	0.00	25.32	78.67	414.9%
2024	15.48	15.48	15.48	0.00	25.65	80.23	418.4%
2025	15.67	15.67	15.67	0.00	25.99	81.81	421.9%
2026	15.88	15.88	15.88	0.00	26.32	83.43	425.3%
2027	16.08	16.08	16.08	0.00	26.66	85.05	428.9%
2028	16.29	16.29	16.29	0.00	27.02	86.72	432.3%
2029	16.50	16.50	16.50	0.00	27.37	88.40	435.7%
2030	16.72	16.72	16.72	0.00	27.72	90.10	438.8%
2031	16.94	16.94	16.94	0.00	28.09	91.82	442.0%
2032	17.16	17.16	17.16	0.00	28.45	93.55	445.1%
2033	17.38	17.38	17.38	0.00	28.81	95.30	448.3%
2034	17.60	17.60	17.60	0.00	29.19	97.07	451.4%
2035	17.84	17.84	17.84	0.00	29.57	98.84	454.2%

Capacity Value (PJM-RTO RPM) ($/MW-Day)

	'BASE' Fleet Transition (1H2013) Carbon in 2022	"Fleet Transition (1H2013)" Alternative Scenarios: HIGHER Band Carbon in 2022	LOWER Band Carbon in 2022	No CO_2	High CO_2 Carbon in 2022	Add'l Scenario: Ultra High CO_2 Carbon in 2022	% CHANGE from "BASE CO_2" (~$15/tonne)	
2014	85.05	85.05	85.05	85.05	85.05	85.05	0.0%	*
2015	131.61	131.61	131.61	131.83	131.83	131.83	0.2%	*
2016	91.30	91.30	91.30	91.30	91.30	91.30	0.0%	*
2017	132.49	148.30	146.90	146.57	127.11	105.88	-20.1%	
2018	199.74	226.24	224.35	223.67	188.69	195.11	-2.3%	
2019	215.54	241.43	240.06	239.28	202.58	253.37	17.6%	
2020	231.74	256.95	256.13	255.23	216.81	303.83	31.1%	
2021	248.55	273.03	272.80	271.78	231.55	310.51	24.9%	
2022	265.99	289.70	290.07	288.92	246.85	317.65	19.4%	
2023	284.08	306.97	307.97	306.69	262.70	324.64	14.3%	
2024	302.83	324.86	326.51	325.10	279.13	331.78	9.6%	
2025	321.95	343.05	345.39	343.84	295.87	339.08	5.3%	
2026	341.74	361.86	364.91	363.22	313.19	346.54	1.4%	
2027	362.23	378.78	378.78	378.78	331.10	354.17	-2.2%	
2028	383.42	386.73	386.73	386.73	349.63	361.60	-5.7%	
2029	394.85	394.85	394.85	394.85	368.79	369.20	-6.5%	
2030	403.15	403.15	403.15	403.15	388.61	376.95	-6.5%	
2031	411.61	411.61	411.61	411.61	409.09	384.87	-6.5%	
2032	420.26	420.26	420.26	420.26	420.26	392.95	-6.5%	
2033	429.08	429.08	429.08	429.08	429.08	401.20	-6.5%	
2034	438.09	438.09	438.09	438.09	438.09	409.63	-6.5%	
2035	447.29	447.29	447.29	447.29	447.29	418.23	-6.5%	

NATURAL GAS (Henry Hub) (REAL, 2011 $) ($/MMBtu)

	'BASE' Fleet Transition (1H2013) Carbon in 2022	"Fleet Transition (1H2013)" Alternative Scenarios: HIGHER Band Carbon in 2022	LOWER Band Carbon in 2022	No CO_2	High CO_2	Add'l Scenario: Ultra High CO_2	% CHANGE from "BASE CO_2" (~$15/tonne)
2014	4.70	4.89	4.51	4.68	4.71	4.99	6.2%
2015	4.97	5.36	4.67	4.95	4.98	5.35	7.8%
2016	5.16	5.93	4.54	5.14	5.17	5.56	7.8%
2017	5.19	5.97	4.57	5.17	5.20	5.59	7.8%
2018	5.16	5.94	4.54	5.15	5.18	5.57	7.8%
2019	5.11	5.87	4.49	5.09	5.12	5.50	7.8%
2020	5.18	5.96	4.56	5.17	5.20	5.59	7.8%
2021	5.33	6.13	4.69	5.22	5.34	6.30	18.3%
2022	5.54	6.37	4.87	5.25	5.65	6.98	26.1%
2023	5.51	6.33	4.85	5.28	5.62	6.94	26.1%
2024	5.54	6.37	4.88	5.31	5.65	6.99	26.1%
2025	5.60	6.43	4.92	5.35	5.71	7.05	26.1%
2026	5.55	6.38	4.88	5.38	5.66	6.99	26.1%
2027	5.56	6.40	4.89	5.39	5.67	7.01	26.1%
2028	5.57	6.40	4.90	5.40	5.68	7.02	26.1%
2029	5.58	6.41	4.91	5.41	5.69	7.03	26.1%
2030	5.54	6.37	4.87	5.37	5.65	6.98	26.1%
2031	5.56	6.39	4.89	5.39	5.67	7.00	26.1%
2032	5.57	6.41	4.90	5.41	5.68	7.03	26.1%
2033	5.59	6.43	4.92	5.42	5.70	7.05	26.1%
2034	5.62	6.46	4.94	5.45	5.73	7.08	26.1%
2035	5.63	6.47	4.95	5.46	5.74	7.10	26.1%

ON-Peak Energy (PJM-AEP Gen Hub) ($/Mwh)

	'BASE' Fleet Transition (1H2013) Carbon in 2022	"Fleet Transition (1H2013)" Alternative Scenarios: HIGHER Band Carbon in 2022	LOWER Band Carbon in 2022	No CO_2	High CO_2 Carbon in 2022	Add'l Scenario: Ultra High CO_2 Carbon in 2022	% CHANGE from "BASE CO_2" (~$15/tonne)	% CHANGE from "NO CO_2"
2014	37.94	41.19	35.87	39.64	37.68	37.64	-0.8%	-5.0%
2015	48.38	51.47	44.99	48.80	47.26	45.23	-6.5%	-7.3%
2016	55.92	62.39	50.47	56.71	55.94	49.90	-10.8%	-12.0%
2017	58.33	64.09	52.96	58.80	57.73	52.72	-9.6%	-10.3%
2018	59.02	64.85	53.72	59.81	58.51	54.40	-7.8%	-9.0%
2019	59.69	65.75	54.28	60.57	59.62	56.24	-5.8%	-7.1%
2020	61.51	67.23	55.91	62.60	61.57	58.67	-4.6%	-6.3%
2021	64.04	70.33	58.17	64.30	64.11	65.67	2.5%	2.1%
2022	72.74	79.19	67.79	65.87	78.00	119.76	64.6%	81.8%
2023	74.33	80.92	68.93	67.40	79.66	123.56	66.2%	83.3%
2024	75.87	82.87	70.34	69.20	81.20	125.08	64.9%	80.8%
2025	77.51	84.94	71.69	70.76	82.56	128.00	65.1%	80.9%
2026	78.86	86.31	72.55	71.98	83.81	129.03	63.6%	79.3%
2027	80.60	88.46	74.52	74.18	85.89	131.61	63.3%	77.4%
2028	81.99	90.44	76.03	75.16	87.26	132.42	61.5%	76.2%
2029	83.65	91.87	76.92	77.03	89.01	133.61	59.7%	73.5%
2030	84.41	92.53	78.73	78.16	89.91	135.73	60.8%	73.7%
2031	86.04	94.97	80.62	79.73	91.90	136.71	58.9%	71.5%
2032	88.14	97.48	82.61	81.36	93.48	139.46	58.2%	71.4%
2033	90.15	99.73	84.21	83.42	95.92	139.77	55.0%	67.6%
2034	88.94	98.01	83.87	81.97	93.64	135.41	52.2%	65.2%
2035	91.25	101.27	86.36	84.28	96.59	138.48	51.8%	64.3%

OFF-Peak Energy (PJM-AEP Gen Hub) ($/Mwh)

	'BASE' Fleet Transition (1H2013) Carbon in 2022	"Fleet Transition (1H2013)" Alternative Scenarios: HIGHER Band Carbon in 2022	LOWER Band Carbon in 2022	No CO_2	High CO_2 Carbon in 2022	Add'l Scenario: Ultra High CO_2 Carbon in 2022	% CHANGE from "BASE CO_2" (~$15/tonne)	% CHANGE from "NO CO_2"
2014	24.50	26.51	22.78	25.06	24.20	24.07	-1.8%	-4.0%
2015	28.52	30.60	26.28	29.29	27.89	27.06	-5.1%	-7.6%
2016	34.10	37.00	30.70	34.89	33.28	29.22	-14.3%	-16.3%
2017	37.38	41.18	33.53	38.62	36.93	31.13	-16.7%	-19.4%
2018	38.37	42.54	34.32	39.60	37.97	32.58	-15.1%	-17.7%
2019	39.25	43.88	34.97	40.61	38.94	34.23	-12.8%	-15.7%
2020	40.76	45.46	36.37	42.24	40.52	35.88	-12.0%	-15.1%
2021	42.25	47.47	37.44	43.44	41.98	38.30	-9.3%	-11.8%
2022	53.89	59.16	49.77	44.64	60.11	96.56	79.2%	116.3%
2023	54.86	60.50	49.96	46.13	61.53	98.41	79.4%	113.3%
2024	56.20	61.71	51.69	47.10	62.49	100.67	79.1%	113.7%
2025	57.24	63.25	51.97	48.21	63.95	102.98	79.9%	113.6%
2026	58.16	64.16	52.27	49.26	65.14	103.55	78.0%	110.2%
2027	59.05	65.42	53.31	50.52	66.18	106.32	80.0%	110.4%
2028	60.20	66.93	54.13	51.55	66.78	106.90	77.6%	107.3%
2029	61.45	68.33	54.90	52.75	68.42	108.66	76.8%	106.0%
2030	62.69	69.66	55.97	53.84	69.32	110.41	76.1%	105.1%
2031	64.20	71.51	57.34	55.27	71.11	111.75	74.1%	102.2%
2032	66.16	74.14	59.03	57.29	72.83	114.16	72.6%	99.3%
2033	68.50	76.63	60.92	59.51	75.04	116.86	70.6%	96.4%
2034	70.00	78.64	62.65	61.00	76.41	117.62	68.0%	92.8%
2035	71.70	80.68	63.91	62.80	78.34	120.39	67.9%	91.7%

* Represents actual cleared forward PJM-RTO Base Residual Auction UCAP clearing prices for those respective XXXX/(XXXX+1) forward PJM Planning Years (represented on a wtd "calendar year" basis).

INDIANA MICHIGAN POWER COMPANY

Rockport Unit 1 Disposition Analysis

Additional CO_2 Price Sensitivity Case

"Ultra High CO_2" (Initial $77/tonne) Price Band Commodity Price Forecast

	CPW ($000)			*CPW Savings vs. 'Option 1' ($000)*		
Disposition Alternative [(1)]	2014-2040 Optimization Period	End-Effects	Total Study Period	2014-2040 Optimization Period	End-Effects	Total Study Period
Option 1 [(2)]	9,422,298	4,680,804	**14,103,102**			-
Option 2A [(3)]	9,443,156	4,739,254	**14,182,410**	20,858	58,450	**79,308**
Option 2B [(4)]	9,407,328	4,783,515	**14,190,843**	(14,970)	102,711	**87,741**

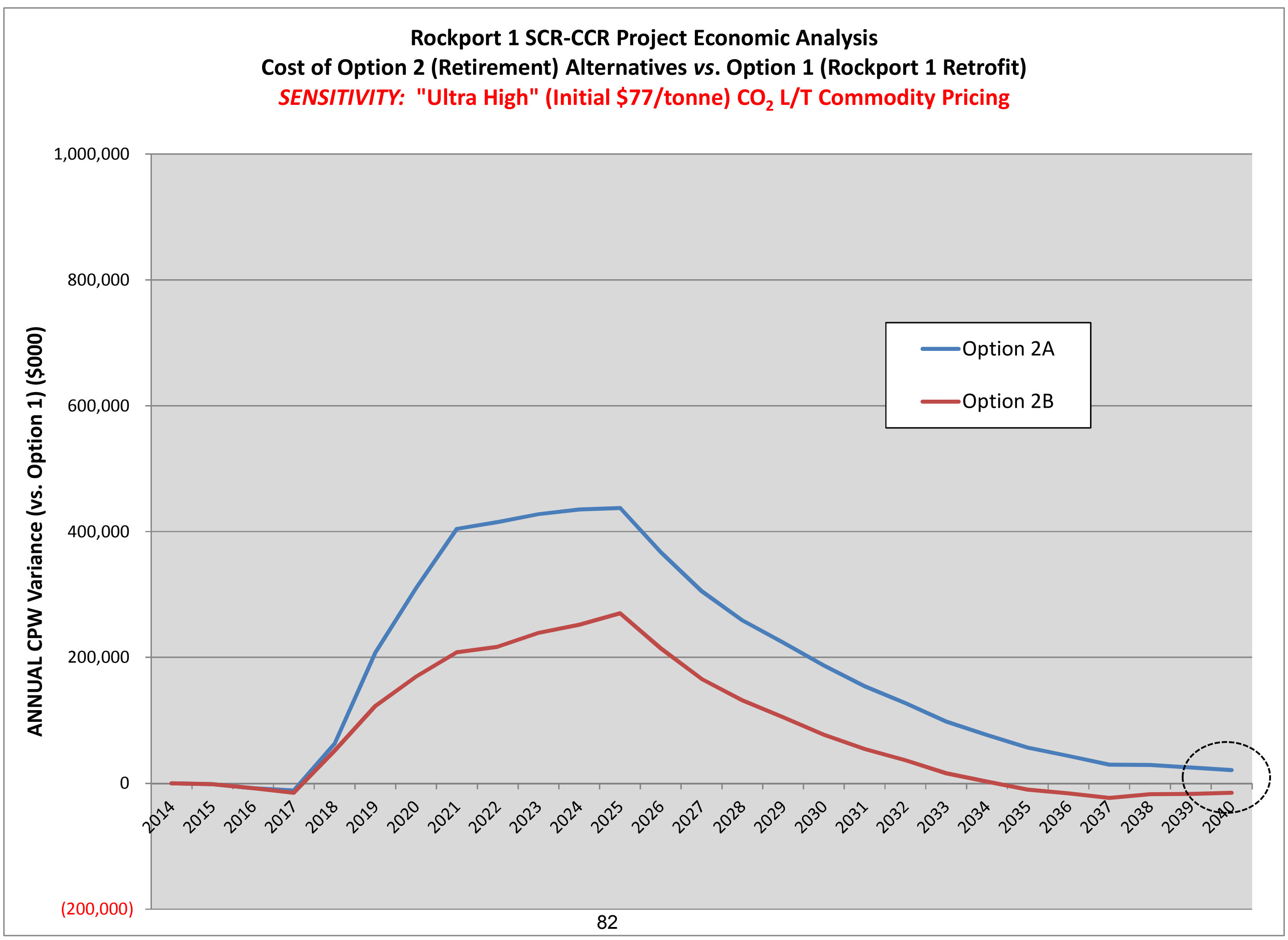
Note:

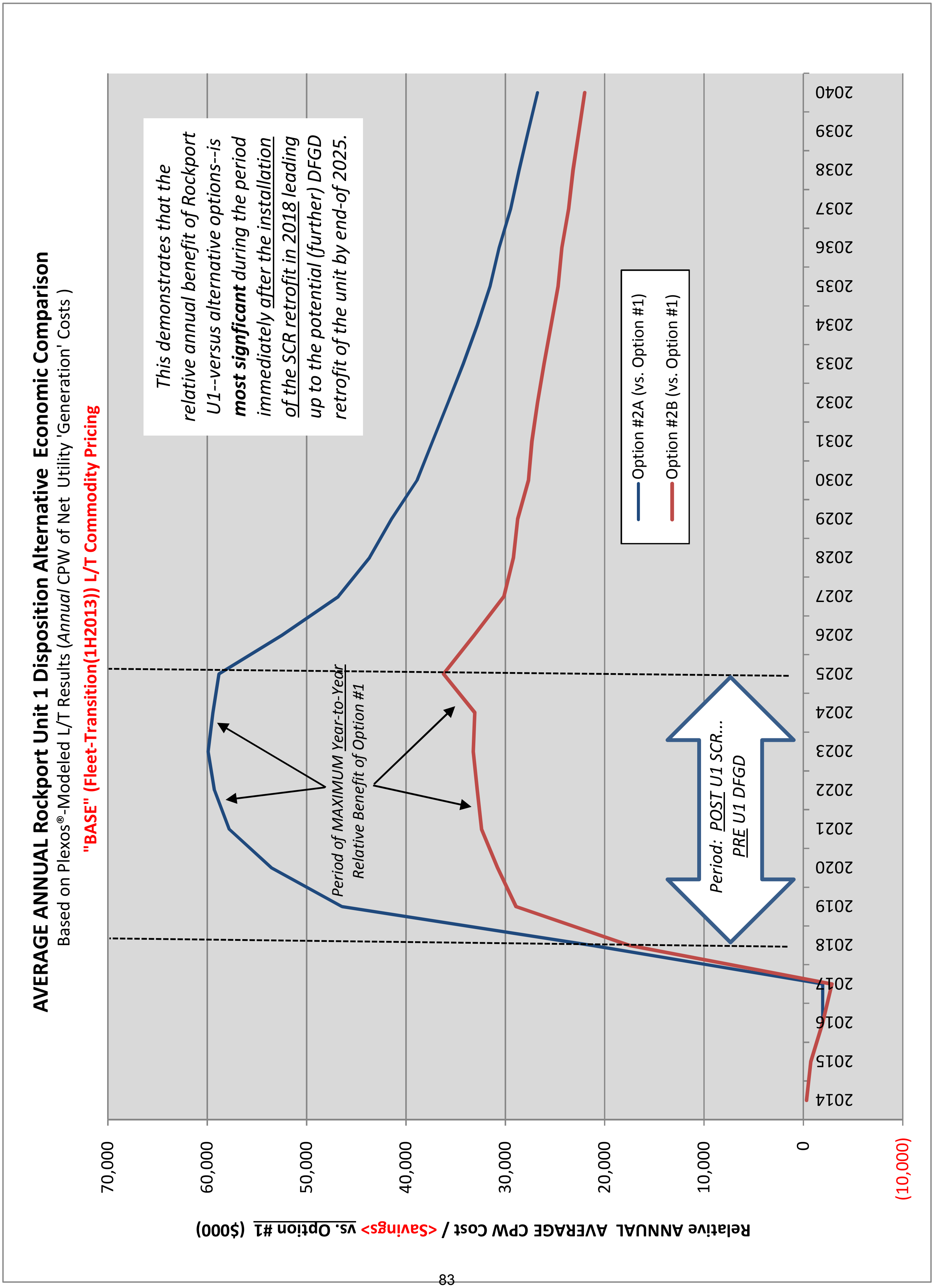
(1) All cases assume Rockport 2 SCR installation in 1/1/2020 and FGD installation in 1/1/2029

(2) Option 1 assumes Rockport U1 SCR installation by 1/1/2018 and FGD installation by 1/1/2026

(3) Option 2A assumes Rockport U1 retired by 1/1/2018 w/ optimal replacement capacity --incl. CC-Build-- by 1/1/2019)

(4) *Same as 'Option 2A' except a replacement nat gas-build --in lieu of PJM market-- not an available replacement alternative until 1/1/2025)*




AVERAGE ANNUAL Rockport Unit 1 Disposition Alternative Economic Comparison
Based on Plexos®-Modeled L/T Results (Annual CPW of Net Utility 'Generation' Costs)
"BASE" (Fleet-Transition(1H2013)) L/T Commodity Pricing
This demonstrates that the relative annual benefit of Rockport U1--versus alternative options--is most signficant during the period immediately after the installation of the SCR retrofit in 2018 leading up to the potential (further) DFGD retrofit of the unit by end-of 2025.
Period of MAXIMUM Year-to-Year Relative Benefit of Option #1
Period: POST U1 SCR... PRE U1 DFGD
Option #2A (vs. Option #1)
Option #2B (vs. Option #1)
Relative ANNUAL AVERAGE CPW Cost / <Savings> vs. Option #1 ($000)
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
(10,000)
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
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2040

Indiana Michigan Power Co.
Rockport Unit 1 Disposition Analysis
Under Base "Fleet Transition (1H2013)" L/T Commodity Pricing

Comparative SHORTER-TERM (thru 2025) CPW of Relative I&M Net Utility "G(eneration)" Costs (2014 $)

Study Year #	Year		Option 1 (Retrofit RK1 with SCR (12/2017)) GRAND Total Net Utility Costs (Cumul. PW) $000	/ Yrs	Option 1 = Total Cost, 'Per Year Avg' (PW) $000		Option 2A (Retire RK1 (12/2017) & Replace w/ Alt-Build Resources 1/2019) GRAND Total Net Utility Costs (Cumul. PW) $000	/ Yrs	Option 2A = Total Cost, 'Per Year Avg' (PW) $000		Option 2B (Retire RK1 (12/2017) & Replace w/ Alt-Build Resources 1/2025) GRAND Total Net Utility Costs (Cumul. PW) $000	/ Yrs	Option 2B = Total Cost, 'Per Year Avg' (PW) $000	Option 2A v. Option 1 Total Cost, 'Per Year Avg' (PW) $000	Option 2B v. Option 1 Total Cost, 'Per Year Avg' (PW) $000
1	2014		409,677	/1	409,677		409,356	/1	409,356		409,356	/1	409,356	(321)	**(321)**
2	2015		743,950	/2	371,975		742,428	/2	371,214		742,428	/2	371,214	(761)	**(761)**
3	2016		1,067,692	/3	355,897		1,061,886	/3	353,962		1,061,886	/3	353,962	(1,935)	**(1,935)**
4	2017		1,323,961	/4	330,990		1,316,168	/4	329,042		1,312,468	/4	328,117	(1,948)	**(2,873)**
5	2018	U1 SCR Installed	1,605,943	/5	321,189	(PJM) Market Resources	1,712,720	/5	342,544	(PJM) Market Resources	1,693,534	/5	338,707	21,355	**17,518**
6	2019		1,904,058	/6	317,343	Alt. 'Build' Resources	2,182,610	/6	363,768		2,077,599	/6	346,266	46,425	**28,923**
7	2020		2,201,529	/7	314,504		2,576,478	/7	368,068		2,417,060	/7	345,294	53,564	**30,790**
8	2021		2,498,667	/8	312,333		2,961,232	/8	370,154		2,757,872	/8	344,734	57,821	**32,401**
9	2022		2,841,542	/9	315,727		3,375,056	/9	375,006		3,137,073	/9	348,564	59,279	**32,837**
10	2023		3,144,898	/10	314,490		3,744,189	/10	374,419		3,477,367	/10	347,737	59,929	**33,247**
11	2024		3,434,412	/11	312,219		4,088,355	/11	371,669		3,798,359	/11	345,305	59,449	**33,086**
12	2025		3,714,132	/ 12	309,511		4,420,117	/ 12	368,343	Alt. 'Build' Resources	4,148,799	/ 12	345,733	**58,832**	**36,222**
13	*2026*	***DFGD Installed***	*4,029,616*	*/ 13*	*309,970*		*4,712,157*	*/ 13*	*362,474*		*4,460,463*	*/ 13*	*343,113*	*52,503*	*33,142*
14	*2027*		*4,330,404*	*/ 14*	*309,315*		*4,985,998*	*/ 14*	*356,143*		*4,752,559*	*/ 14*	*339,469*	*46,828*	*30,154*
15	*2028*		*4,597,352*	*/ 15*	*306,490*		*5,252,375*	*/ 15*	*350,158*		*5,035,297*	*/ 15*	*335,686*	*43,668*	*29,196*
16	*2029*		*4,911,494*	*/ 16*	*306,968*		*5,574,606*	*/ 16*	*348,413*		*5,371,705*	*/ 16*	*335,732*	*41,445*	*28,763*
17	*2030*		*5,188,684*	*/ 17*	*305,217*		*5,849,755*	*/ 17*	*344,103*		*5,659,173*	*/ 17*	*332,893*	*38,887*	*27,676*
18	*2031*		*5,440,005*	*/ 18*	*302,222*		*6,112,008*	*/ 18*	*339,556*		*5,932,006*	*/ 18*	*329,556*	*37,334*	*27,333*
19	*2032*		*5,675,434*	*/ 19*	*298,707*		*6,355,040*	*/ 19*	*334,476*		*6,184,167*	*/ 19*	*325,482*	*35,769*	*26,775*
20	*2033*		*5,910,474*	*/ 20*	*295,524*		*6,595,358*	*/ 20*	*329,768*		*6,432,825*	*/ 20*	*321,641*	*34,244*	*26,118*
21	*2034*		*6,131,791*	*/ 21*	*291,990*		*6,821,405*	*/ 21*	*324,829*		*6,665,196*	*/ 21*	*317,390*	*32,839*	*25,400*
22	*2035*		*6,336,589*	*/ 22*	*288,027*		*7,030,270*	*/ 22*	*319,558*		*6,879,826*	*/ 22*	*312,719*	*31,531*	*24,693*
23	*2036*		*6,650,895*	*/ 23*	*289,169*		*7,355,751*	*/ 23*	*319,815*		*7,210,570*	*/ 23*	*313,503*	*30,646*	*24,334*
24	*2037*		*6,950,324*	*/ 24*	*289,597*		*7,657,335*	*/ 24*	*319,056*		*7,517,008*	*/ 24*	*313,209*	*29,459*	*23,612*
25	*2038*		*7,350,634*	*/ 25*	*294,025*		*8,066,187*	*/ 25*	*322,647*		*7,930,201*	*/ 25*	*317,208*	*28,622*	*23,183*
26	*2039*		*7,728,499*	*/ 26*	*297,250*		*8,448,374*	*/ 26*	*324,937*		*8,316,107*	*/ 26*	*319,850*	*27,688*	*22,600*
27	*2040*		*8,074,330*	*/ 27*	*299,049*		*8,796,897*	*/ 27*	*325,811*		*8,668,458*	*/ 27*	*321,054*	***26,762***	***22,005***

CO_2 Price Report, Spring 2014

Includes 2013 CO_2 Price Forecast

May 22, 2014

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1. EXECUTIVE SUMMARY

Prudent planning requires electric utilities and other stakeholders in carbon-intensive industries to use a reasonable estimate of the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. However, forecasting a CO_2 price can be difficult. While several bills have been introduced in Congress, the federal government has yet to legislate a policy to reduce greenhouse gas emissions in the United States.

Although this lack of a defined policy setting a price on carbon poses a challenge in CO_2 price forecasting, an assumption that there will be no CO_2 price in the long run is not, in our view, reasonable. The scientific basis for attributing climatic changes to human-driven greenhouse gas emissions is irrefutable, as are the type and scale of damages expected to both infrastructure and ecosystems. The need for a comprehensive U.S. effort to reduce greenhouse gas emissions is clear. Any policy requiring or leading to greenhouse gas emission reductions will result in higher costs to the electricity resources that emit CO_2.

This Spring 2014 report updates Synapse's November 2013 Carbon Dioxide Price Forecast with the most recent information on federal regulatory measures, state and regional climate policies, and utility CO_2 price forecasts. The Synapse CO_2 price forecast is designed to provide a reasonable range of price estimates for use in utility Integrated Resource Planning (IRP) and other electricity resource planning analyses. We have not reevaluated the forecast itself. We have only reviewed and updated our summary of the key regulatory developments and data from utility IRPs, which are frequently changing and crucial to understanding the impetus for a carbon price forecast and the number of utilities that have adopted one for planning purposes. The Low, Mid and High Synapse CO_2 price forecasts presented in this report are identical to those published in the November 2013 report.[1] We continue to refer to this forecast as the 2013 forecast. We plan to release another edition of this report later in 2014, in which we will revisit the 2013 forecast.

1.1. Key Assumptions

This report includes updated information on federal regulations, state and regional climate policies, and utility CO_2 price forecasts. The low, mid, and high Synapse CO_2 price forecasts presented here are identical to those in the November 2013 report. Synapse's November 2013 CO_2 price forecast reflected our expert judgment that near-term regulatory measures to reduce greenhouse gas emissions, coupled with longer-term cap-and-trade or carbon tax legislation passed by Congress, will result in significant pressure to decarbonize the electric power sector. The key assumptions of our forecast included:

[1] Luckow P., E. Stanton, B. Biewald, J. Fisher, F. Ackerman, E. Hausman. *2013 Carbon Dioxide Price Forecast*. Synapse Energy Economics, November 2013.

- A federal program establishing a price for greenhouse gases is the probable eventual outcome, as it allows for a least-cost path to emissions reduction.
- Initial climate-focused policy actions are more likely to take a regulatory approach, e.g. Section 111(d) of the Clean Air Act. In the longer term, federal legislation setting a price on emissions through a cap-and-trade policy or a carbon tax will likely be prompted by one or more of the following factors:
    - New technological opportunities that lower the cost of carbon mitigation;
    - A patchwork of state policies that achieve state emission targets for 2020, spurring industry demands for federal action;
    - A series of executive actions taken by the President that spur demand for Congressional action;
    - A Supreme Court decision that permits lawsuits, making it possible for states to sue companies within their boundaries that own high-carbon-emitting resources, and creating a financial incentive for energy companies to act; and
    - Mounting public outcry in response to increasingly compelling evidence of human-driven climate change.

Given the growing interest in reducing greenhouse gas emissions by states and municipalities throughout the nation, a lack of timely, substantive federal action will result in the enactment of diverse state and local policies. Heterogeneous—and potentially incompatible—sub-national climate policies would present a challenge to any company seeking to invest in CO_2-emitting power plants, both existing and new. Historically, there has been a pattern of states and regions leading with energy and environmental initiatives that have in time been superseded at the national level. It seems likely that this will be the dynamic going forward: a combination of state and regional actions, together with federal regulations, that are eventually eclipsed by a comprehensive federal carbon price.

We expect that federal regulatory measures together with regional and state policies will lead to the existence of a cost associated with greenhouse gas reductions in the near term. Prudent utility planning requires that utilities take this cost into account when engaging in resource planning, even before a federal carbon price is enacted.

1.2. Study Approach

In this report, Synapse reviews several key developments that have occurred over the past six months. These include:

- Proposed federal regulatory measures to limit CO_2 emissions from new power plants and administrative initiatives to advance regulation for existing units;
- Revisions to the Northeast's Regional Greenhouse Gas Initiative (RGGI) CO_2 policy and the most recent auctions under both RGGI and California's AB 32 Cap-and-Trade program;

- Synapse's collection and analysis of carbon price forecasts from the most recent IRP efforts of 46 utilities.

1.3. Synapse's 2013 CO_2 Price Forecast

Based on analyses of the sources described in Synapse's November 2013 Carbon Dioxide Price Forecast report, and relying on our own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2013 to 2040. We have not reevaluated these forecasts since the November 2013 report. Figure ES-1 (below) shows the range covered by the Synapse forecasts. These projections assume that state and regional policies will combine with federal regulatory measures to put economic pressure on carbon-emitting resources in the next several years such that the costs of operating a high-carbon-emitting plant increase—followed later by a broader federal, market-based policy. In states other than the RGGI region[2] and California, we assume a zero carbon price for the next several years; by 2020, we expect that federal regulatory measures will begin to put economic pressure on carbon-emitting power plants throughout the United States. All annual carbon prices are reported in 2012 dollars per short ton of CO_2.[3]

Each of the forecasts shown in Figure ES-1 represents a different level of political will for reducing carbon emissions, as described below.

- The **Low case** forecasts a carbon price that begins in 2020 at $10 per ton, and increases to $40 per ton in 2040, representing a $22 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies—either regulatory or legislative—exist but are not very stringent.
- The **Mid case** forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $60 per ton in 2040, representing a $34 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals.
- The **High case** forecasts a carbon price that begins in 2020 at $25 per ton, and increases to approximately $90 per ton in 2040, representing a $52 per ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising carbon prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technological alternatives such as nuclear, biomass, and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

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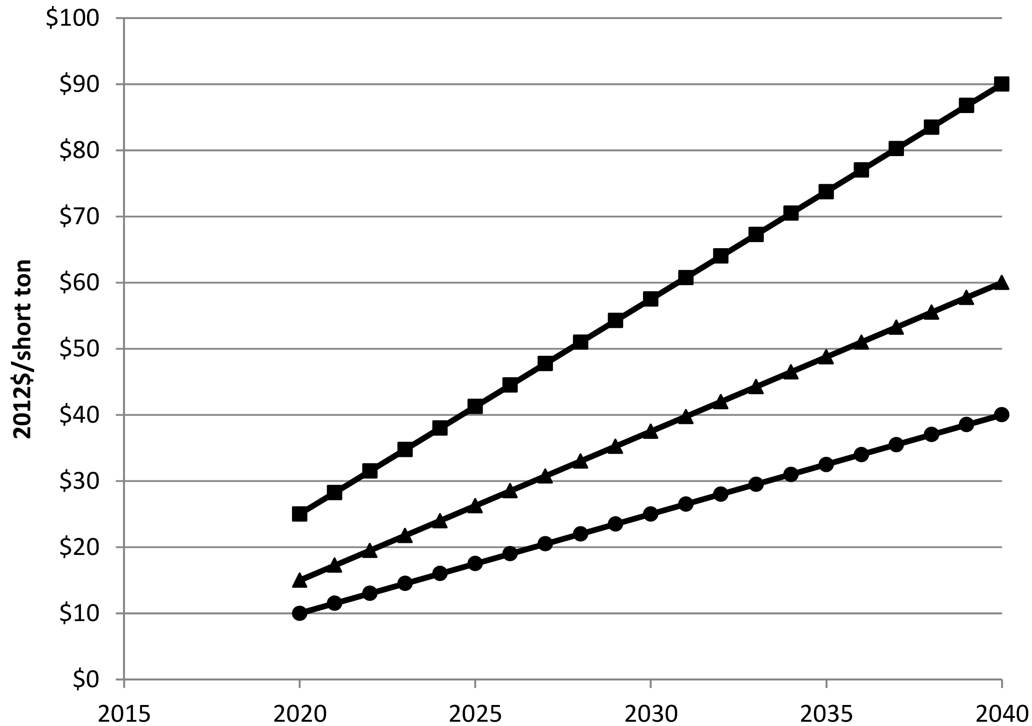
[2] Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

[3] Results from public modeling analyses were converted to 2012 dollars using price deflators taken from the U.S. Bureau of Economic Analysis, and are available at: http://www.bea.gov/national/nipaweb/SelectTable.asp. Consistent with U.S. Energy Information Administration and U.S. Environmental Protection Agency modeling analyses, a 5 percent real discount rate was used in all levelization calculations.

ES-1: Synapse 2013 CO_2 Price Trajectories



2. STRUCTURE OF THIS REPORT

This report presents Synapse's 2013 Low, Mid and High CO_2 price forecasts, along with the evidence assembled to inform these forecasts, and key updates to this evidence that reflect developments from the past six months:

- Section 3 discusses broader concepts of CO_2 pricing.
- Sections 4 through 8 discuss existing state and federal legislation, potential future legislation, recent cap-and-trade results from the research community, and a range of current CO_2 price forecasts from utilities.
- Section 9 presents Synapse's 2013 Low, Mid, and High CO_2 price forecast, along with a comparison to recent utility forecasts.

Unless otherwise indicated, all prices are in 2012 dollars and CO_2 emissions are given in short tons.

3. WHAT IS A CARBON PRICE?

There are several co-existing meanings for the term “carbon price” or “CO_2 price”: each of these meanings is appropriate in its own context. Here we give a brief introduction to five common types of carbon prices, along with a quick guide to which of the carbon price estimates reviewed in this report are based on which of these meanings. (Note that the definition of an additional term—the “price of carbon”—is ambiguous because it can at times mean several of the following.)

Carbon allowances (sometimes called credits or certificates, and best known for their use in policies called “cap and trade”): Allowances are certificates that give their holder the right to emit a unit of a particular pollutant. A fixed number of carbon allowances are issued by a government, some sold and, perhaps, some given away.[4] Subsequent trade of allowances in a secondary market is common to this policy design. The price that firms must pay to obtain allowances increases their cost of doing business, thereby giving an advantage to firms with cleaner, greener operations, and creating an incentive to lower emissions whenever it can be done for less than the price of allowances. The number of allowances—the “cap” in the cap-and-trade system—reflects the required society-wide emission reduction target. A greater reduction target results in a lower cap and a higher price for allowances. In the field of economics, pricing emissions is called “internalizing an externality”: the external (not borne by the polluting enterprise) cost of pollution damages is assigned a market price (thus making it internal to the enterprise).

In this report: The Northeast’s RGGI and California’s Cap-and-Trade Program are both carbon allowance trading systems. In addition, the Kerry-Lieberman, Waxman-Markey, and Cantwell-Collins bills all proposed policy measures that included carbon allowance trading.

Carbon tax: A carbon tax also internalizes the externality of carbon pollution, but instead of selling or giving away rights to pollute (the allowance approach), a carbon tax creates an obligation for firms to pay a fee for each unit of carbon that they emit. In theory, if the value of damages were known with certainty, a tax could internalize the damages more accurately, by setting the tax rate equal to the damages; in practice, the valuation of damages is typically uncertain. In contrast to the government issuance of allowances, with a carbon tax there is no fixed amount of possible emissions (no “cap”). A cap-and-trade system specifies the amount of emission reduction, allowing variation in the price; a tax specifies the price on emissions, allowing variation in the resulting reductions. In both cases there is an incentive to reduce emissions whenever it can be done for less than the prevailing price. In both cases there is the option to continue emitting pollution, at the cost of either buying allowances or paying the tax. While some advocates have claimed that a tax is administratively simpler and reduces bureaucratic, regulatory, and compliance costs, a general aversion to new taxes has meant that no carbon tax proposals have received substantial support in recent policy debate.

[4] Regardless of whether allowances are initially given away for free or sold, they represent an opportunity cost of emissions to the holder.

Effective price of carbon (sometimes called the notional, hypothetical, or voluntary price): Carbon allowances and carbon taxes internalize the climate change externality by making polluters pay. However, many other types of climate policies work not by making polluting more expensive per se, but instead by requiring firms to use one technology instead of another, or to maintain particular emission limitations in order to avoid legal repercussions. Non-market-based emission control regulatory policies are called "command and control." For any such non-market policy there is an "effective" price: a market price that—if instituted as an allowance or tax—would result in the identical emission reduction as the non-market policy. An effective price may be used internally within a firm, government agency, or other entity to represent the effects of command and control policies for the purpose of improved decision making. Renewable Portfolio Standards, energy efficiency measures, and other policies designed to mitigate CO_2 emissions impose an effective price on carbon.

In this report: Utility carbon price forecasts are effective prices used for state-required IRPs and internal planning purposes. The U.S. Environmental Protection Agency's (EPA's) proposed carbon pollution standard for new sources of electric generation is a non-market-based policy that would represent an effective price.

Marginal abatement cost of carbon: An abatement cost refers to an estimate of the expected cost of reducing emissions of a particular pollutant. Estimation of a marginal abatement cost requires the construction of a "supply curve": all of the possible solutions to controlling emissions (these may be technologies or policies) are lined up in order of their cost per unit of pollution reduction. Then, starting from the least expensive option, one tallies up the pollution reduction from various solutions until the desired total reduction is achieved, and then asks: what would it cost to reduce emissions by the last unit needed to achieve the target? The answer is the "marginal" cost of that level of pollution reduction; a greater reduction target would have a higher marginal cost. The marginal abatement cost of carbon is not a market price used to internalize an externality. Rather, it is a method for estimating the price that, if it were applied as a market price, would have the effect of achieving a given emission reduction target. In a well-functioning cap-and-trade system, the allowance price would tend towards the marginal abatement cost of carbon.

In this report: We do not analyze any marginal abatement costs in this report—see the *2012 Synapse Carbon Dioxide Price Forecast* for further information.[5] McKinsey & Company has been a consistent producer of this type of analysis, an example being its 2010 report *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*.

Social cost of carbon: Whereas the marginal abatement cost estimates the price of stopping pollution, the social cost of carbon estimates the cost, per unit of emissions, of allowing pollution to continue. The social cost of carbon is the societal cost of current and future damages related to climate change resulting from the emission of one additional unit of pollutant. Estimating the uncertain costs of

[5] Wilson et al. *2012 Carbon Dioxide Price Forecast.* Synapse Energy Economics, October 2012. Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf.

uncertain future damages from uncertain future climatic events is, of course, a tricky business. If enough information were available, a marginal abatement cost for each level of future emissions (the supply of emission reductions) could be compared to a social cost of carbon for each level of future emissions (the demand for emission reductions) to determine an "optimal" level of pollution (such that the next higher unit of emission reduction would cost more to achieve than its value in reduced damages). More commonly, the social cost of carbon is used as part of the calculation of benefits of emission-reducing measures.

In this report: The U.S. federal government's internal carbon price for use in policy making is an estimate of the social cost of carbon.

4. FEDERAL CLIMATE ACTION IS INCREASINGLY LIKELY

In the near term, comprehensive federal climate legislation appears unlikely to come out of a divided Congress. The Executive Branch, however, is moving forward with regulatory actions to limit greenhouse gas emissions. Following a directive issued by President Obama, EPA released revised CO_2 performance standards for new power plants on September 20, 2013.[6] In June 2013, President Obama also instructed EPA to use its Clean Air Act authority to propose CO_2 standards for existing power plants by June 2014 and to finalize these standards by June 2015.[7] On March 31, 2014, the White House Office of Management and Budget (OMB) began a formal review of the EPA's standards for existing power plants.[8] Beyond the realm of electric sector CO_2 policies (which are the focus of this report), similar regulatory measures have been proposed for the transportation, buildings, and industrial sectors; policies enacted in other sectors include vehicle efficiency standards set to rise to 54.5 miles per gallon by 2025 for new cars and light-duty trucks, and new energy efficiency standards for federal buildings set to reduce energy consumption by nearly 20 percent.[9,10]

We continue to expect that a federal cap-and-trade program for greenhouse gases is the most likely policy outcome in the long term, because it permits reductions to come from sources that can mitigate emissions at the lowest cost. While state and regional policies combined with federal regulatory actions

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[6] EPA. "2013 Proposed Carbon Pollution Standard for New Power Plants." Available at: http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

[7] Memorandum from President Obama to Administrator of the Environmental Protection Agency, Power Sector Carbon Pollution Standards (June 25, 2013). Available at: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[8] Office of Information and Regulatory Affairs. "Pending EO 12866 Regulatory Review." Received 03/31/2014. http://www.reginfo.gov/public/do/eoDetails?rrid=123943.

[9] Vlasic, Bill. "US Sets Higher Fuel Efficiency Standards." *The New York Times*. August 28th, 2012. Available at: http://www.nytimes.com/2012/08/29/business/energy-environment/obama-unveils-tighter-fuel-efficiency-standards.html.

[10] "Energy Efficiency Design Standards for New Federal Commercial and Multi-Family High-Rise Residential Buildings." A Rule by the Department of Energy. July 9th, 2013. Available at: https://www.federalregister.gov/articles/2013/07/09/2013-16297/energy-efficiency-design-standards-for-new-federal-commercial-and-multi-family-high-rise-residential#h-9.

appear to be more likely than a federal cap-and-trade policy in the near term, according to a World Resources Institute (WRI) analysis these local measures are unlikely to be able to meet long-term goals of reducing total greenhouse gas emissions to 83 percent below 2005 levels by 2050, even in the most aggressive of scenarios.[11]

4.1. Regulatory Measures for Reducing Greenhouse Gas Emissions

There are a number of federal regulations that directly and indirectly mandate a reduction in greenhouse gas emissions in the power sector. These are summarized in Table 1 and described in detail below.

[11] See WRI's analysis of these scenarios in the 2013 report "Can the U.S. Get There From Here?: Using Existing Federal Laws and State Action to Reduce Greenhouse Gas Emissions." Available at: http://www.wri.org/publication/can-us-get-there-from-here.

Table 1: Summary of power sector regulatory measures that may result in reduced greenhouse gas emissions

Rule	Current Status as of Release	Next Deadline(s)	Pollutants Covered
Federal Regulations			
Clean Air Act, Section 111	~EPA released a revised 111(b) rule, New Source Performance Standards for GHGs from new sources, in September 2013	~Awaiting final rule	CO_2 and other greenhouse gases
	~A draft 111(d) rule controlling GHGs from existing sources was submitted on March 31, 2014	~June 2014: EPA must propose standards for existing power plants	
		~June 2015: EPA must finalize standards for existing power plants	
		~June 2016: States must submit State Implementation Plans (SIPs) to EPA	
National Ambient Air Quality Standards (NAAQS)	~1-Hour SO_2 NAAQS was finalized in June 2010	~Initial designations based on monitoring data were made in June 2013; additional designations expected by or before 2017	Sulfur dioxide; nitrogen dioxide; carbon monoxide; ozone; particulate matter; and lead
	~PM2.5 annual NAAQS was finalized on December 2012	~Final designations expected in December 2014; SIPs due three years later with attainment required by 2020	
	~8-Hour Ozone NAAQS was finalized in March 2008	~Final designations delayed until April 2012 and SIPs are due in 2015	
		~The standard is currently under review, proposed rule updating the standard is required in December 2014 and final rule by October 1, 2015	
Cross State Air Pollution Rule (CSAPR)	~The U.S. Supreme Court reinstated CSAPR in April 2014, finding that EPA had not exceeded its authority in crafting the rule	~CSAPR Phase II was to begin on January 1, 2014; EPA is in the process of determining new compliance deadlines for the reinstated CSAPR rule; CAIR requirements remain in place until then	Nitrogen oxides and sulfur dioxide
Mercury and Air Toxics Standards (MATS)	~Finalized in December 2011	~April 16, 2015: Compliance deadline (rule allows for a one-year extension if certain conditions are met)	Mercury, metal toxins, organic and inorganic hazardous air pollutants, and acid gases
Coal Combustion Residuals (CCR) Disposal Rule	~EPA first proposed to regulate CCR in June 2010	~EPA has signed a consent decree requiring the Agency to issue a final CCR rule by December 19, 2014	Coal combustion residuals (ash)
Steam Electric Effluent Guidelines (ELGs)	~EPA released a proposed rule with eight regulatory options in June 2013	~September 30, 2015: Rule for release of toxins into waterways must be finalized	Toxins entering waterways
Cooling Water Intake Structure (316(b)) Rule	~EPA released a final rule for implementation of Section 316(b) of the Clean Water Act on May 19, 2014	~Final rule becomes effective 60 days after publication in the Federal Register (likely ~August 2014) and requirements will be implemented in NPDES permits as they are renewed	Cooling water
Regional Haze Rule	~Regional Haze Rule issued in July 1999	~States must file SIPs and install the Best Available Retrofit Technology (BART) controls within 5 years of SIP approval	Sulfur oxides, nitrogen oxides, and particulate matter

Clean Air Act

As a result of the 2007 Supreme Court finding in *Massachusetts v. EPA*, greenhouse gas emissions were determined to be subject to the Clean Air Act and (in a later ruling) to contribute to air pollution anticipated to endanger public health and welfare. In 2009, EPA issued an "endangerment finding," obligating the agency to regulate emissions of greenhouse gases from stationary sources such as power plants.[12] EPA released draft New Source Performance Standards (NSPS) in April 2012 and revised NSPS standards in September 2013. The revised standards limit CO_2 emissions from new fossil-fuel power plants to 1,000-1,100 pounds of CO_2 per MWh (lbs/MWh)—a level achievable by a new natural gas combined-cycle plant. The exact limit of CO_2 emissions within that range depend on the type of plant and period over which the emission rate would be averaged.[13]

Under Section 111(d) of the Clean Air Act, the EPA is required to propose standards for existing power plants by June 2014, but there remains substantial uncertainty over what form these regulations will take. Unit-specific emission rates standards, such as the NSPS for greenhouse gases, are only one of several plausible options. Unit-specific standards could apply to power plants based on categories by fuel type and technology type, each with its own maximum emission rate. Units that are not in compliance could undertake upgrades to improve efficiency; however, these kinds of upgrades can be expensive, can only achieve small, one-time changes to emission rates, and could trigger New Source Review/Prevention of Significant Deterioration (NSR/PSD) provisions, increasing the cost further.[14,15]

Other regulatory design options for existing plants under 111(d) include maintaining a state-wide average maximum emission rate, and market-based (e.g., cap-and-trade) approaches. More flexible mechanisms like these could lower the cost of compliance, but could also result in additional legal challenges as compared to a simpler but more rigid system of unit-specific regulation.[16] An Edison Electric Institute white paper on potential regulation of existing sources notes that "because of concerns about legal challenges to the guidelines, EPA may be reluctant to incorporate a wide range of compliance flexibility mechanisms in the guidelines, but may be more receptive to such mechanisms if proposed by the states in compliance plans."[17]

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[12] EPA. "Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act." Available at: http://www.epa.gov/climatechange/endangerment/.

[13] EPA. "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units." Available at: http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf.

[14] EEI. "Existing Source GHGH NSPS White Paper," Page 5. Available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf.

[15] Tarr J., Monast J., Profeta T. "Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act." The Nicholas Institute. January 2013. Available at: http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_r_13-01.pdf.

[16] Fine, Steven and MacCracken, Chris. "President Obama's Climate Action Plan: What It Could Mean to the Power Sector." ICF International. August 2013. Available at: http://www.icfi.com/insights/white-papers/2013/president-obama-climate-action-plan.

[17] Edison Electric Institute. "Existing Source GHG NSPS White Paper," Page 2. Available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf.

End-use energy efficiency may be an important part of a comprehensive compliance strategy for a regulation that averages emission rates across states. States may be able to achieve emissions reductions at a lower cost through the structures of their existing energy efficiency resource standards.

Methods for demonstrating compliance with 111(d) may be similar to existing regulations: in a process similar to Section 110 of the Clean Air Act, under which EPA sets National Ambient Air Quality Standards (NAAQS), states will be required to submit State Implementation Plans (SIPs) that specify how they intend to comply with 111(d). EPA can then decide whether a proposed SIP meets the terms of the regulation; in the absence of an acceptable SIP, EPA can impose a Federal Implementation Plan (FIP). Under the schedule outlined by President Obama in his Climate Action Plan, regulations for existing sources under 111(d) will be finalized by June 2015, and states will be required to submit SIPs to the EPA by June 2016. A draft 111(d) rule was sent to the Office of Management and Budget (OMB) for review on March 31, 2014.[18]

Performance standards for new and existing sources will affect decisions made by utilities regarding operation, expansion, and retirements. Enforcement of the Clean Air Act creates an opportunity cost of greenhouse gas abatement: prudent utilities will take Clean Air Act compliance into consideration in their planning, either explicitly as a maximum allowable emissions rate, or implicitly as an effective carbon price. An NRDC analysis of the impacts of 111(d) implementation estimated compliance costs under this policy at $7.53 per ton of CO_2 avoided.[19]

Other regulatory measures put economic pressure on carbon-intensive power plants

A suite of current and proposed EPA regulations require pollution-intensive power plants to install environmental controls for compliance. The cost of complying with environmental regulations reduces the profitability of the worst polluters, sometimes rendering them uneconomic. These policies demonstrate momentum towards appropriately regulating or pricing environmentally harmful activities in the electric sector. To the extent that plants with high emissions of other pollutants also have high carbon emissions, these policies would tend to *lower* the future CO_2 price necessary to achieve a given reduction; as more pollution-intensive plants retire in response to other EPA regulations, the necessary carbon price is reduced. Specific regulatory measures include:

- *National Ambient Air Quality Standards (NAAQS)* set maximum air quality limitations that must be met at all locations across the nation. EPA has established NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter—measured as particulate matter less than or equal to 10

[18] Office of Management and Budget. "Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions From Existing Stationary Sources: Electric Utility Generating Units." Received 03/31/2014. http://www.reginfo.gov/public/do/eoDetails?rrid=123943

[19] Natural Resources Defense Council. "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters," March 2013. Available at: http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf.

micrometers in diameter (PM10) and particulate matter less than or equal to 2.5 micrometers in diameter (PM2.5)—and lead.

- *The Cross State Air Pollution Rule (CSAPR)*, finalized in 2011, establishes the obligations of each affected state to reduce emissions of NO_x and SO_2 that significantly contribute to another state's PM2.5 and ozone non-attainment problems. CSAPR was vacated by the U.S. Court of Appeals for the District of Columbia in August 2012. The Supreme Court agreed to review the Appeals Court's decision, and on April 29, 2014, CSAPR was reinstated by the high court. Significantly, the Court found that EPA had not exceeded its authority in crafting an emission control program that utilized cap and trade and considered cost as a factor where the language of the Clean Air Act was ambiguous in addressing the complex problem of interstate transport of pollution.
- *Mercury and Air Toxics Standards (MATS)*: The final MATS rule, approved in December 2011, sets stack emissions limits for mercury, other metal toxins, organic and inorganic hazardous air pollutants, and acid gases. Compliance with MATS is required by 2015, with a potential extension to 2016. Many utilities have already committed to capital improvements at their coal plants to comply with the standard. In fact, the EIA recently found that 70 percent of U.S. coal-fired power plants already comply with MATS.[20]
- *Coal Combustion Residuals (CCR) Disposal Rule:* In June 2010, EPA proposed to regulate CCR for the first time, either under Subtitle C (used primarily for hazardous waste) or Subtitle D (municipal solid waste) of the Resource Conservation and Recovery Act. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required. In addition, the EPA would implement minimum requirements for dam safety at impoundments. Under a solid waste Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care. On January 29, 2014, EPA signed a Consent Decree with environmental groups promising to issue a final CCR rule by December 19, 2014.[21]
- *Steam Electric Effluent Limitation Guidelines (ELGs):* On June 7, 2013, EPA released eight regulatory options for new, proposed steam-electric ELGs to reduce or eliminate the release of toxins into U.S. waterways. A final rule is required by September 30, 2015.[22] New requirements will be implemented in 2015 to 2020 through the five-year National Pollutant Discharge Elimination System permit cycle.[23]
- *Cooling Water Intake Structure (§316(b)) Rule:* In March 2011, EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act

[20] See U.S. Energy Information Administration website. Accessed April 15, 2014. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=15611
[21] See January 29, 2014 Consent Decree. Available at: http://earthjustice.org/sites/default/files/files/044-1-Consent-Decree.pdf
[22] See U.S. Environmental Protection Agency website. Accessed April 15, 2014. Available at: http://water.epa.gov/scitech/wastetech/guide/steam-electric/amendment.cfm.
[23] See U.S. Environmental Protection Agency. Steam Electric ELG Rulemaking. UMRA and Federalism Implications: Consultation Meeting. October 11, 2011. http://water.epa.gov/scitech/wastetech/guide/upload/Steam-Electric-ELG-Rulemaking-UMRA-and-Federalism-Implications-Consultation-Meeting-Presentation.pdf.

at existing power plants that withdraw large volumes of water from nearby water bodies. Under this rule, EPA would set new standards to reduce the impingement and entrainment of fish and other aquatic organisms from cooling water intake structures at electric generating facilities. The final rule was released on May 19, 2014.The requirements of the rule will be implemented through renewal of a facility's NPDES permit, which must be renewed every five years. [24]

- *Regional Haze Rule:* The Regional Haze Rule, released in July 1999, requires states to develop implementation plans (SIPs) for reducing emissions that impair visibility at pristine areas such as national parks. The rule also requires periodic SIP updates to ensure progress is being made toward improving visibility. The initial development of SIPs, which is just now being completed, requires Best Available Retrofit Technology (BART) controls for SOx, NOx, and PM emissions on large emission sources built between 1962 and 1977 that are found to be contributing to visibility impairment. BART controls must be installed within five years of SIP approval.

4.2. Proposed Cap-and-Trade Legislation

Over the past decade, there have been several Congressional proposals to legislate cap-and-trade programs, with the goal of reducing greenhouse gas emissions by up to 83 percent below recent levels by 2050 through a federal cap. Such programs would allow trading of allowances to promote least-cost reductions in greenhouse gas emissions.

Comprehensive climate legislation was passed by the House in 2009: the American Clean Energy and Security Act, also known as Waxman-Markey or H.R. 2454. However, the Senate did not vote on either of the two climate bills before it in the 2009-2010 session (Kerry-Lieberman APA 2010 and Cantwell-Collins S. 2877). Waxman-Markey was a cap-and-trade program that would have required a 17 percent reduction in emissions from 2005 levels by 2020, and an 83 percent reduction by 2050.[25] Further analysis of these proposals is provided in Synapse's 2012 Carbon Dioxide Price Forecast.[26]

Congressional interest in climate policy has been ongoing. In March 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012 (S. 2146), which would have required larger utilities to meet a percentage of their sales with electric generation from sources that produce less greenhouse gas emissions than a conventional coal-fired power plant. Credits generated by these clean technologies would have been tradable with a market price. In February 2013, Senators Sanders and Boxer introduced new comprehensive climate change legislation, the Climate Protection Act of 2013. This bill

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[24] See U.S. Environmental Protection Agency website. Accessed May 21, 2014. Available at: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm.

[25] U.S. Energy Information Administration (EIA); Energy Market and Economic Impacts of the American Power Act of 2010 (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html. EIA; Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009 (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html.

[26] Wilson et al., "2012 Carbon Dioxide Price Forecast," October 2012. http://www.synapse-energy.com/Downloads/SynapseReport. 2012-10.0.2012-CO2-Forecast.A0035.pdf.

proposed a carbon fee of $20 per ton of CO_2 or CO_2 equivalent content of methane, rising at 5.6 percent per year over a ten-year period. The bill has not yet been brought to a vote.

As discussed earlier, we expect that federal cap-and-trade legislation will eventually be enacted but that it is unlikely to happen in the near term. Federal carbon regulations are in effect or under development today, and the economic pressure—or opportunity cost—that they create may be represented as an effective price of greenhouse gas emissions. Regulatory measures are unlikely to meet long-term goals of reducing total greenhouse gas emissions to approximately 80 percent below 2005 levels by 2050, and a broader approach will be increasingly attractive in order to meet these goals at lower costs. Our judgment indicates this is most likely to take the form of a federal cap-and-trade system.

5. STATE AND REGIONAL CLIMATE POLICIES

There are two regional and state cap-and-trade programs in the United States today: the Northeast's RGGI and California's Cap-and-Trade Program under AB32. In addition, a total of 20 states plus the District of Columbia have set greenhouse gas emissions targets as low as 80 percent below 1990 levels by 2050.[27]

Recent Revisions to RGGI

RGGI is a cap-and-trade greenhouse gas program for power plants in the northeastern United States. Current participant states are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. RGGI has had more than five years of successful CO_2 allowance auctions, with Auction 23 resulting in a clearing price of $4.00 per ton.[28] RGGI is designed to reduce electricity sector CO_2 emissions to at least 45 percent below 2005 levels by 2020.[29]

When RGGI was established in 2007, the expectation was that the CO_2 emissions allowance auction would generate revenues for consumer benefit programs such as energy efficiency, renewable energy, and clean energy technologies. While RGGI has provided significant revenues for consumer benefit, its allowance prices have generally remained near the statutory minimum price. External influences, including changes to fuel prices, caused a shift from coal and oil to lower-carbon natural gas generation.

[27] "Greenhouse Gas Emissions Targets." Center for Climate and Energy Solutions. Accessed September 13, 2013. Available at: http://www.c2es.org/us-states-regions/policy-maps/emissions-targets.

[28] RGGI Auction 23 results available at: http://rggi.org/market/co2_auctions/results/Auction-23.

[29] RGGI. "RGGI States Propose Lowering Regional CO_2 Emission Cap 45%, Implementing a More Flexible Cost-Control Mechanism." February 2013. Available at: http://www.rggi.org/docs/PressReleases/PR130207_ModelRule.pdf.

Compared to those external factors, the effect of the original RGGI cap requirements were relatively minor in meeting the goals of reducing CO_2 emissions in the power sector.[30]

In 2012 and 2013, the RGGI states evaluated a number of plans for tighter emissions caps with the goal of raising allowance prices. In February of 2013, participating states agreed to lower the CO_2 cap from 165 million to 91 million short tons in 2014, to be reduced by 2.5 percent each year from 2015 to 2020. RGGI analysis indicates that with these lower caps, allowance prices will rise to $4.16 per short ton in 2014, increasing to $10.40 per ton in 2020.[24]

In March 2014, the first auction under the new cap cleared at $4 per short ton. This auction used all available "cost containment reserve" allowances for the year—a fixed additional supply of allowances (above the cap) at a fixed price ($4 in 2014, rising to $10 in 2017) used to prevent rapid increases in the allowance price. Given that no more cost containment reserve allowances are available for the remaining three auctions in 2014, it is quite possible that prices in these auctions will clear above $4 per ton.

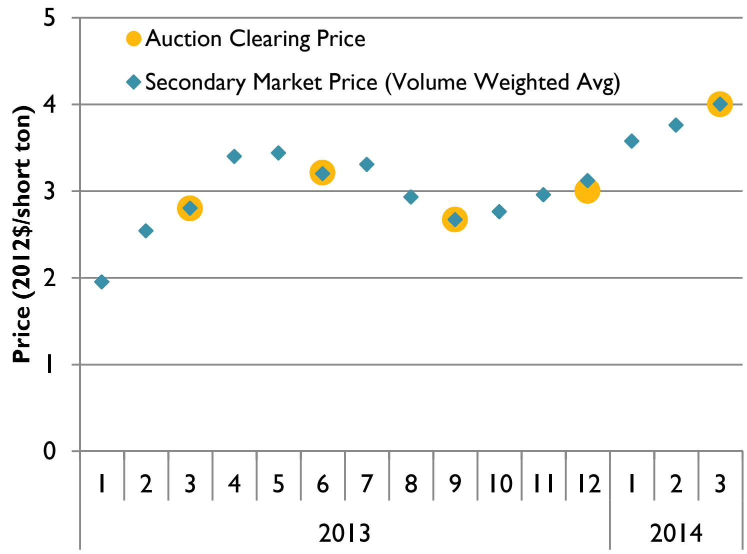
The March 2014 clearing price was the highest-ever clearing price at a RGGI auction. While the primary market for allowances is the official RGGI auction held four times per year, RGGI allowances can be resold to another party in the secondary market after an auction has concluded.[31] This secondary market allows firms to obtain allowances at any point during the year, not just the four official auctions, and allows for futures and options contracts, giving firms more opportunities to manage their risk. Secondary market prices have historically tracked auction prices closely, with both rising steadily since September 2013. Figure 1 shows secondary market prices and auction clearing prices since 2013. Prices rose in Q2 2013 with the announcement of the revised CO_2 cap, and—after a brief dip in the summer 2013—have risen in each month and quarter since September 2013.[32]

[30] Environment Northeast. "RGGI at One Year: An Evaluation of the Design and Implementation of the Regional Greenhouse Gas Initiative." February 2010. Available at: http://www.env-ne.org/public/resources/pdf/ENE_2009_RGGI_Evaluation_20100223_FINAL.pdf.

[31] All secondary market transactions resulting in a transfer of allowance ownership are registered in RGGI's CO_2 Allowance Tracking System (COATS).

[32] RGGI CO_2 Allowance Tracking System, Transaction Price Report. Accessed Mar. 28 2014. Available at: https://rggi-coats.org/eats/rggi/index.cfm.

Figure 1: RGGI auction clearing prices and secondary market prices



California's Cap-and-Trade-Program under AB32

With the goal of reducing the state's emissions to 1990 levels by 2020, California's Global Warming Solutions Act (AB32) has created the world's second largest carbon market, after the European Union's Emissions Trading System. The first compliance period for California's Cap-and-Trade Program began on January 1, 2013 and covers electricity generators, CO_2 suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 27,600 tons of CO_2e per year.[33,34] On February 19, 2014, the California Air Resources Board held its sixth quarterly allowance auction, resulting in a clearing price of $11.48 per ton.[35] This first phase of the program includes electricity generators and large industrials. Phase II, beginning in 2015, will also include transportation fuels and smaller industrial sources.

In 2014, the California Air Resources Board will auction at least 118 million allowances, up from 96 million allowances in 2013. The reserve price will increase from $10.71 per ton to $11.34 per ton, consistent with a requirement for the price to increase 5 percent every year plus the rate of inflation.[36]

On January 1, 2014, California and Québec formally linked their carbon markets, although the first joint auction will not be held until later in 2014. Québec is expected to be a net buyer from California. Québec's target will likely to be harder to meet: with an electricity system largely based on hydropower

[33] "CO_2e" refers to CO_2-equivalent, the combination of CO_2 and an equivalent value for other greenhouse gases.

[34] CARB 2013a. "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments by Linked Jurisdictions." July 2013. Available at: http://www.arb.ca.gov/cc/capandtrade/ctlinkqc.pdf. Legislated value is 25,000 metric tons, converted here to short tons.

[35] CARB 2013b. "CARB Quarterly Auction 6, February 2014: Summary Results Report." February 24, 2014. Available at: http://www.arb.ca.gov/cc/capandtrade/auction/february-2014/results.pdf.

[36] California Carbon. "California to auction 118 million emission allowances in 2014, increases reserve price by 6%". December 2, 2013. Available at: http://californiacarbon.info/2013/12/02/california-to-auction-118-million-emission-allowances-in-2014-increases-reserve-price-by-6/.

and overall much smaller than California's, there are fewer easy opportunities for emissions reductions. Québec's March 4 auction cleared at $11.39 in Canadian dollars, similar in magnitude to California allowance prices.[37]

6. ASSESSMENT OF CARBON PRICE FOR FEDERAL RULEMAKING

In 2010, the U.S. federal government began including a carbon cost in regulatory rulemakings to account for the climate damages resulting from each additional ton of greenhouse gas emissions;[38] updated values were released in 2013.[39] The 2013 Economic Report of the President acknowledges that these values will continue to be updated as scientific understanding improves.[40] When updated values were released in 2013, the Office of Management and Budget (OMB) invited comments from interested parties. Several authors of this CO_2 price report submitted comments providing further analysis of the values used and the process used to develop them.[41]

An Interagency Working Group on the Social Cost of Carbon—composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, Department of Transportation, and Office of Management and Budget, among others—was tasked with the development of a consistent value for the social benefits of climate change abatement. Four values were developed (see Section 3 for more explanation of the "social cost of carbon" methodology). These values—$11, $36, $55, and $101 per ton of CO_2 in 2013, expressed in 2007$ and rising over time—represent average (most likely) damages at three discount rates, along with one estimate at the 95th percentile of the assumed distribution of climate impacts.[42,43] While subject to significant uncertainty,

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[37] Morehouse, E. "California and Quebec: A Partnership Par Excellence." Environmental Defense Fund. March 7, 2014. Available at: http://blogs.edf.org/californiadream/2014/03/07/california-and-quebec-a-partnership-par-excellance/.

[38] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.

[39] Interagency Working Group on the Social Cost of Carbon (2013) Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866. Available at: http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf.

[40] 2013 Economic Report of the President (2013). Chapter 6. March 2013. Available at: http://www.whitehouse.gov/sites/default/files/docs/erp2013/ERP2013_Chapter_6.pdf.

[41] Stanton, E. A., F. Ackerman, and J. Daniel. 2014. "Comments on the 2013 Technical Update of the Social Cost of Carbon." Synapse Energy Economics for the Environment, Economics and Society Institute. Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2014-01.0.SCC-Comments.14-008.pdf.

[42] These values represent recently revised costs for the SCC. Originally, these values were $5, $21, $35, and $65 per metric tonne for the year 2010 in 2007 dollars.

[43] In a 2012 paper, Ackerman and Stanton modified the Interagency Working Group's assumptions regarding uncertainty in the sensitivity of temperature change to emissions, the expected level of damages at low and high greenhouse gas concentrations, and the assumed discount rate, and found values for the social cost of carbon ranging from the Working Group's level up to more than an order of magnitude greater [Frank Ackerman and Elizabeth A. Stanton (2012). "Climate Risks and Carbon Prices: Revising the Social Cost of Carbon." *Economics: The Open-Access, Open-Assessment E-Journal*, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10]. Similarly, Laurie Johnson and Chris Hope modified

this multi-agency effort represents an initial attempt at incorporating the benefits associated with CO_2 abatement into federal policy.

As of May 2012, these estimates had been used in at least 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[44, 45] In the first rule in which the revised 2013 values were used—improving energy efficiency in microwave ovens—the net present value of benefits over a 30-year timeframe increased by $400 million as a result of the increase in effective carbon price.[46] While a carbon price for federal rulemaking assessments is a fundamentally different kind of cost metric than the others discussed in this report, it nonetheless represents a dollar value for greenhouse gas emissions currently in use by the U.S. federal government.

7. RECENT CO_2 PRICE FORECASTS FROM THE RESEARCH COMMUNITY

The Energy Modeling Forum (EMF), a working group of government and private modeling teams, has been convening to explore energy system issues since the late 1970s. The group recently completed its EMF 24 analysis with the objective of evaluating what CO_2 price trajectories are consistent with proposed emission reduction targets under different technology scenarios. This analysis also incorporated several complementary policies with a cap-and-trade proposal, including: transportation emissions reduction through vehicle gas mileage standards; renewable portfolio standards in the electric sector; and mandates that all new coal facilities employ carbon capture and storage (CCS) technology—a policy similar to EPA's proposed NSPS for coal plants. Nine modeling teams participated in this study.[47]

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discount rates and methodologies and found results up to 12 times larger than the Working Group's central estimate [Laurie T. Johnson, Chris Hope. "The social cost of carbon in U.S. regulatory impact analyses: an introduction and critique." *Journal of Environmental Studies and Sciences*, 2012; DOI: 10.1007/s13412-012-0087-7].

[44] Robert E. Kopp and Bryan K. Mignone (2012). "The U.S. Government's Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement." Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15.

[45] See, for example, "Rulemaking for Microwave Ovens Energy Conservation Standard: Technical Support Document." May 2013. Available at: http://www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx/ruleid/37.

[46] Brad Blumer. "The social cost of carbon is on the rise." The Washington Post, June 6th, 2013. Available at: http://articles.washingtonpost.com/2013-06-06/business/39789409_1_carbon-dioxide-emissions-obama-administration.

[47] Clarke, L.C., A.A. Fawcett, J.P. Weyant, V. Chaturvedi, J. MacFarland, Y. Zhou, "Technology and U.S. Emissions Reductions Goals: Results of the EMF 24 Modeling Exercise," and Fawcett, A.A., L.C. Clarke, S. Rausch, J.P. Weyant, "Overview of EMF 24 Policy Scenarios," both forthcoming in *The Energy Journal*.

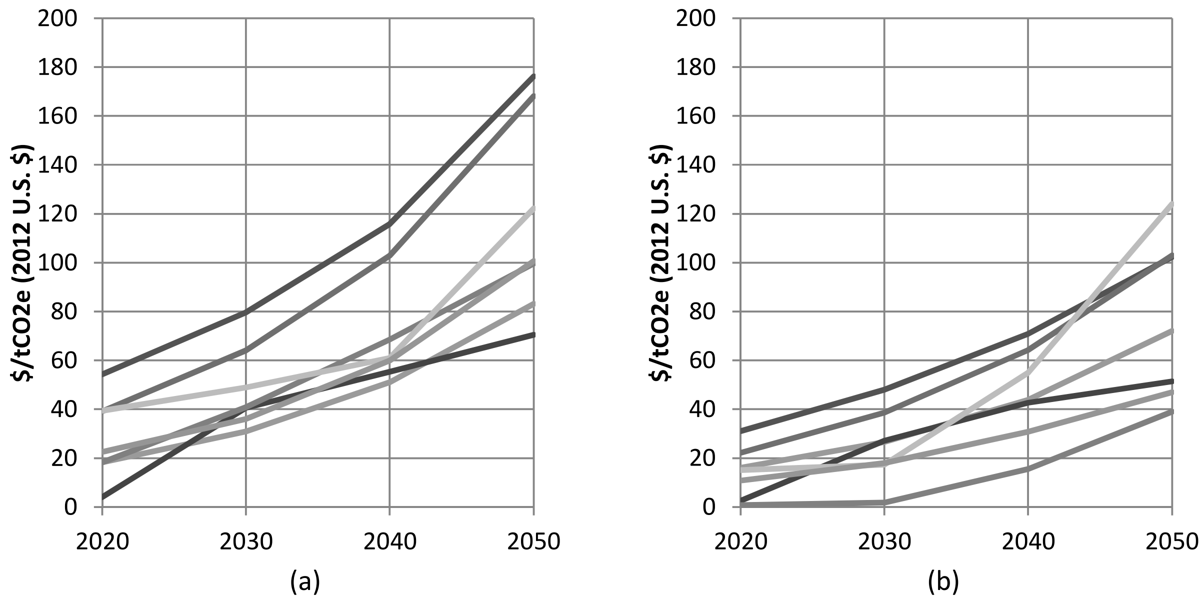
Results from the EMF 24 exercise show a range of CO_2 price trajectories depending on availability of new technologies, policy type, model baseline trajectories, and other structural characteristics of the models. One question asked by this study is of particular relevance to users of the Synapse CO_2 price forecast: which economic sectors would emissions reductions come from in an economically efficient approach to emissions mitigation? Consistent with earlier EMF analyses, the electric sector was found to be the largest contributor to CO_2 emissions reductions across all models.

Under a cap-and-trade scenario designed to reduce energy system emissions 50 percent below 2005 levels by 2050, most of the EMF 24 models reduced electric sector emissions by 75 percent by 2050. Under an 80 percent emissions reduction scenario, most of the additional emissions reductions came from other sectors. Although CO_2 prices are higher under the 80 percent scenario, most electricity customers are not paying these prices, as the electricity sector is largely decarbonized before 2050.

CO_2 prices estimated by the EMF 24 models show substantial variation. While it is difficult to distinguish the roles of model structure and model assumptions in this variation, the results present a reasonable range across which prices may fall. Under the most optimistic technology assumptions, with low-cost renewables, high levels of energy efficiency, and availability of new nuclear and CCS, CO_2 prices in 2020 fell between $10 and $40 per ton of carbon dioxide. In contrast, prices fell between $20 and $80 under the most pessimistic assumptions. Complementary policies, such as renewable portfolio standards or fuel economy standards, reduce carbon prices, as indicated in Figure 1.

Universally, the models show that substantial emissions reductions are not achievable in the absence of a carbon reduction policy. Even in the most optimistic technology scenario, the most aggressive emissions reductions from any model in the absence of a carbon policy was 0.19 percent per year, resulting in emissions 7 percent below 2005 levels in 2050.

Figure 2: Range of allowance prices from EMF 24 study under (a) 50 percent cap-and-trade policy and with (b) the addition of several complementary policies (optimistic CCS/nuclear technology assumptions). Models include USREP, US-REGEN, NewERA, GCAM, FARM, EC-IAM, and ADAGE. [50]



8. CO_2 PRICE FORECASTS IN UTILITY IRPS

A growing number of electric utilities include projections of the costs that will be associated with greenhouse gas emissions in their resource planning procedures. In addition to the pool of recent IRPs reviewed for this forecast, which are characterized below, Synapse has previously conducted an extensive study of resource plans dating back to 2003. None of the 15 IRPs published from 2003-2007 that we reviewed included a CO_2 price forecast. Beginning in 2008, the number of IRPs that include a CO_2 price has risen drastically. Of the 56 IRPs from 2008-2011 that we reviewed, 23 included a CO_2 price forecast. This jump in the inclusion of carbon price projections in IRPs from 2008 onwards coincided with the introduction of the Waxman-Markey bill in Congress, which sought to legislate a cap-and-trade system. As a result of this bill, the inclusion of carbon pricing sensitivities in IRPs became paramount to prudent planning beginning in 2008; a majority of the IRPs in our most recent review reflect this understanding. Of the 91 IRPs released in 2012-2013 reviewed by Synapse (referred to below as our current "sample"), 46 include a CO_2 price in at least one scenario, and 42 include a CO_2 price in their reference case scenario. This data shows that the resource plans in the latest sample, despite being produced entirely after the failure of Congress to pass comprehensive climate legislation, includes a similar fraction of IRPs with a CO_2 price forecast as the 2008-2011 sample, when major climate bills were under consideration.

How well does our sample represent utility planning across the United States? A total of 3,412 utilities operated in the United States in 2012.[48] In terms of generation, the top 5 percent—170 utilities—accounted for 77 percent of total U.S. generation in 2012. Our sample includes IRPs from 29 utilities within this largest 5 percent. Of those 29, 25 utilities have IRPs with non-zero CO_2 prices. This means that almost all of the IRPs we reviewed from the largest utilities in the country include a non-zero CO_2 price in their planning process.

Overall, our entire sample of 91 2012-2013 IRPs comes from utilities that represent 20 percent of total sales nationally, where:

- Those IRPs with non-zero CO_2 price forecasts in any scenario come from utilities that represent more than 18 percent of total U.S. sales,
- Those IRPs with no consideration of CO_2 prices come from utilities that represent less than 2 percent of total U.S. sales.[49]

Additional statistics describing these forecasts are provided in Table 2. The IRPs in our sample represent roughly a fifth of total U.S. generating capacity and CO_2 emissions. Given the substantial number of utilities that keep large portions of their IRPs confidential, as well as utilities who do not complete IRPs (discussed below), we are confident this is a reasonable sample size.

Table 2: IRP Sample Size Statistics

Utility Summary	Number of Utilities	Generation (TWh)	Sales (TWh)	Capacity (GW)	Customers (Million)	CO_2 Emissions (million tons)
US Totals - from EIA 860 data	3,412	4,043	3,695	1,168	155	2,209
All IRPs Analyzed						
All Years	162	-	-	-	-	-
2012 - 2013 Sample	91	-	-	-	-	-
With CO_2 Prices (2012 - 2013 Sample)	46	-	-	-	-	-
IRPs Matched to EIA 860 data						
2012 - 2013 Sample	64	774	756	205	29	495
% of US Totals	*2%*	*19%*	*20%*	*18%*	*18%*	*22%*
With CO_2 Prices (2012 - 2013 Sample)	40	688	672	175	25	401
% of US Totals	*1%*	*17%*	*18%*	*15%*	*16%*	*18%*

Source: EIA Form 860, 2012 (Released Oct. 10, 2013).

[48] EIA Form 860, 2012 (Released Oct. 10, 2013).

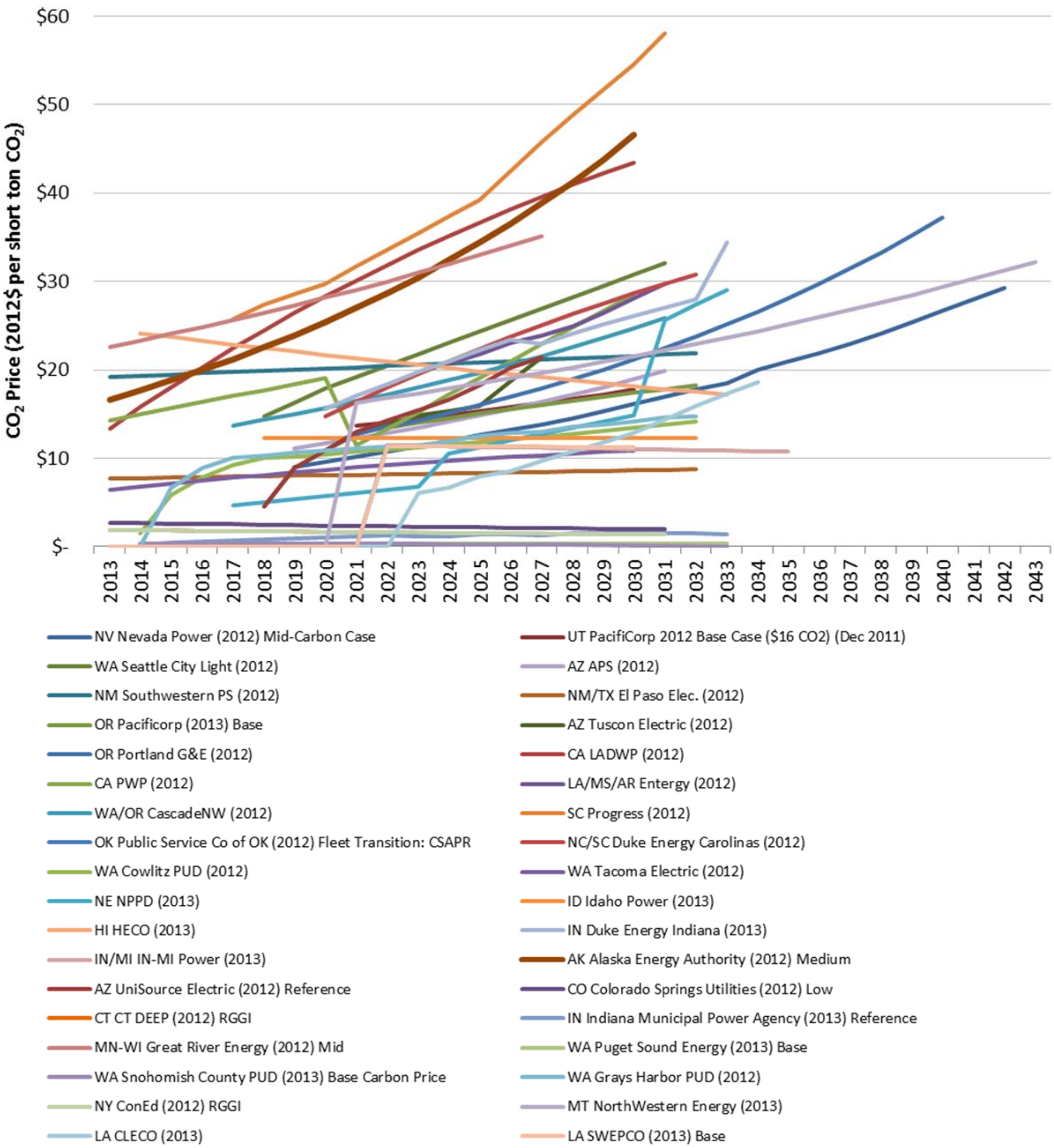
[49] Two forecasts in Figure 3 are not included in the sales total: Alaska Energy Authority and Connecticut Department of Energy and Environmental Protection cover multiple utilities in their respective states, and could not be matched to just one.

Not all utilities produce IRPs. In fact, 11 states have no filing requirements for long-term planning, while 10 other states require long-term plans, but not IRPs.[50] While long-term planning is an important part of the procurement process in regions with wholesale energy markets, the traditional utility-centric integrated resource plan is less common in competitive markets. As a result, regions with wholesale markets are not well represented in our sample.

Figure 3 below displays non-zero, non-confidential reference case CO_2 price forecasts from 36 utility IRPs over the period of 2013-2043. Although we refer to 42 non-zero reference case forecasts above, six reference case forecasts with non-zero CO_2 prices are excluded from this chart: there are three instances of the same company operating in multiple states producing multiple IRPs but using the same CO_2 forecast; two are non-zero but confidential; and one forecasts a non-zero price beginning after the company's IRP study period ends in 2023 and is thus not provided in the IRP. On average, the non-zero reference case forecasts in Figure 3 begin forecasting a price for CO_2 in 2017.

[50] See: Wilson, R. and B. Biewald. *Best Practices in Electric Utility Integrated Resource Planning*. June 1, 2013. Synapse Energy Economics. Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2013-06.RAP.Best-Practices-in-IRP.13-038.pdf.

Figure 3: Utility Non-zero and Non-confidential Reference Case Forecasts from 2012 and 2013[51]



Note: The CO_2 forecasts from CLECO and SWEPCO are provided in publicly available planning assumption documents in preparation for IRPs to be released at a later date.

[51] Six non-zero, non-confidential reference case forecasts are excluded, discussed further on page 22.

Four of the utility forecasts displayed in Figure 3 are particularly low in the context of the other forecasts. Two IRPs from the Northeast—Commonwealth Edison of New York and the Connecticut Department of Energy and Environmental Protection—base their reference case forecasts on RGGI prices before the recent RGGI revisions discussed in Section 5, resulting in prices just under $2 per short ton. Two other IRPs—Puget Sound Energy and Snohomish County PUD—use a Washington State mandated CO_2 price of $0.32 per short ton for their base case analyses.

The four utilities that assume a $0 CO_2 price in their reference cases also consider several additional non-zero scenarios. These are provided in Appendix A.

Table 3 summarizes the range of CO_2 prices forecasted for 2020 and 2030 from the 36 utility IRPs. Not all forecasts start by 2020, and those that do are generally below $20 per ton. Of the utilities with a non-zero CO_2 price, all but five assume a price in 2030; some of the missing five have planning periods that end before 2030.

Table 3: Number of Utility CO_2 Forecasts from 2012-2013 in several price ranges in 2020 and 2030

	2020	2030
<$10	10	5
$10 - $20	11	14
$20 - $30	6	8
$30 - $40	0	1
>=$40	0	3

9. OVERVIEW OF THE EVIDENCE FOR A FUTURE CO_2 PRICE

Our CO_2 price forecasts are developed based on the data sources and information presented above and reflect a reasonable range of expectations regarding future efforts to limit greenhouse gas emissions. The following items have guided the development of the Synapse forecasts:

- **Regulatory measures limiting CO_2 emissions from power plants will be implemented in the near term**. The EPA is required to propose emissions standards for existing power plants under Section 111(d) of the Clean Air Act by June 2014. Standards for new power plants were proposed in September 2013. These actions represent an effective price that will affect utility planning and operational decisions.

- **State and regional action limiting CO_2 is ongoing and growing more stringent**. In the Northeast, the RGGI CO_2 cap has been tightened, resulting in higher CO_2 prices for electric generators in the region. California's Cap-and-Trade Program, which represents an even larger carbon market than RGGI, has held many successful allowance auctions, and has been successfully defended against numerous legal challenges.

- **A price for CO_2 is already being factored into federal rulemakings.** The federal government has demonstrated a commitment to considering the benefits of CO_2 abatement in rulemakings such as fuel economy and appliance standards.

- **Ongoing analysis of emissions caps suggests a wide range of possible prices.** Important factors include the stringency of any future climate policy, the existence of complementary policies, technology availability, and how quickly old capital stock can be phased out in favor of new technologies.

- **Electric suppliers continue to account for the opportunity cost of CO_2 abatement in their resource planning.** Prudent planning requires utilities to consider adequately the potential for future policies. The range of carbon prices reported in Section 8 indicates that many utilities believe that by 2020 there will likely be significant economic pressure towards low-carbon electric generation.

10. Synapse 2013 CO_2 Price Forecast

Based on analyses of the sources described in our 2013 Carbon Dioxide Price Forecast report from November, and relying on our own expert judgment, Synapse has developed Low, Mid, and High case forecasts for CO_2 prices from 2013 to 2040. We have not reevaluated these forecasts based on the updated information on federal regulatory measures limiting CO_2, state climate action, and utility CO_2 pricing presented in this report. Figure 4 and Table 4 show the Synapse forecasts over this period.

Figure 4: Synapse 2013 CO_2 Price Trajectories

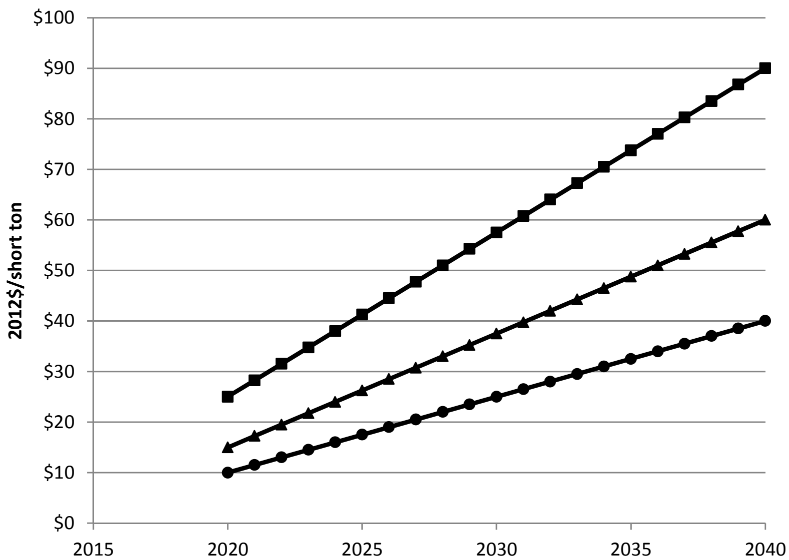


Table 4: Synapse 2013 CO_2 Price Projections (2012 dollars per short ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$10.00	$15.00	$25.00
2021	$11.50	$17.25	$28.25
2022	$13.00	$19.50	$31.50
2023	$14.50	$21.75	$34.75
2024	$16.00	$24.00	$38.00
2025	$17.50	$26.25	$41.25
2026	$19.00	$28.50	$44.50
2027	$20.50	$30.75	$47.75
2028	$22.00	$33.00	$51.00
2029	$23.50	$35.25	$54.25
2030	$25.00	$37.50	$57.50
2031	$26.50	$39.75	$60.75
2032	$28.00	$42.00	$64.00
2033	$29.50	$44.25	$67.25
2034	$31.00	$46.50	$70.50
2035	$32.50	$48.75	$73.75
2036	$34.00	$51.00	$77.00
2037	$35.50	$53.25	$80.25
2038	$37.00	$55.50	$83.50
2039	$38.50	$57.75	$86.75
2040	$40.00	$60.00	$90.00
Levelized 2020-2040	$22.36	$33.54	$51.79

In these forecasts, state and regional policies, together with federal regulatory measures, place economic pressure on CO_2-emitting resources in the next several years, such that it is relatively more expensive to operate a high-carbon-emitting power plant. These pressures are followed later by a broader federal policy, such as cap and trade. In any state other than the RGGI region and California, we assume a zero carbon price through 2019; beginning in 2020, we expect that federal regulatory measures will put economic pressure on carbon-emitting power plants throughout the United States. All annual allowance prices and levelized values are reported in 2012 dollars per short ton of carbon dioxide.

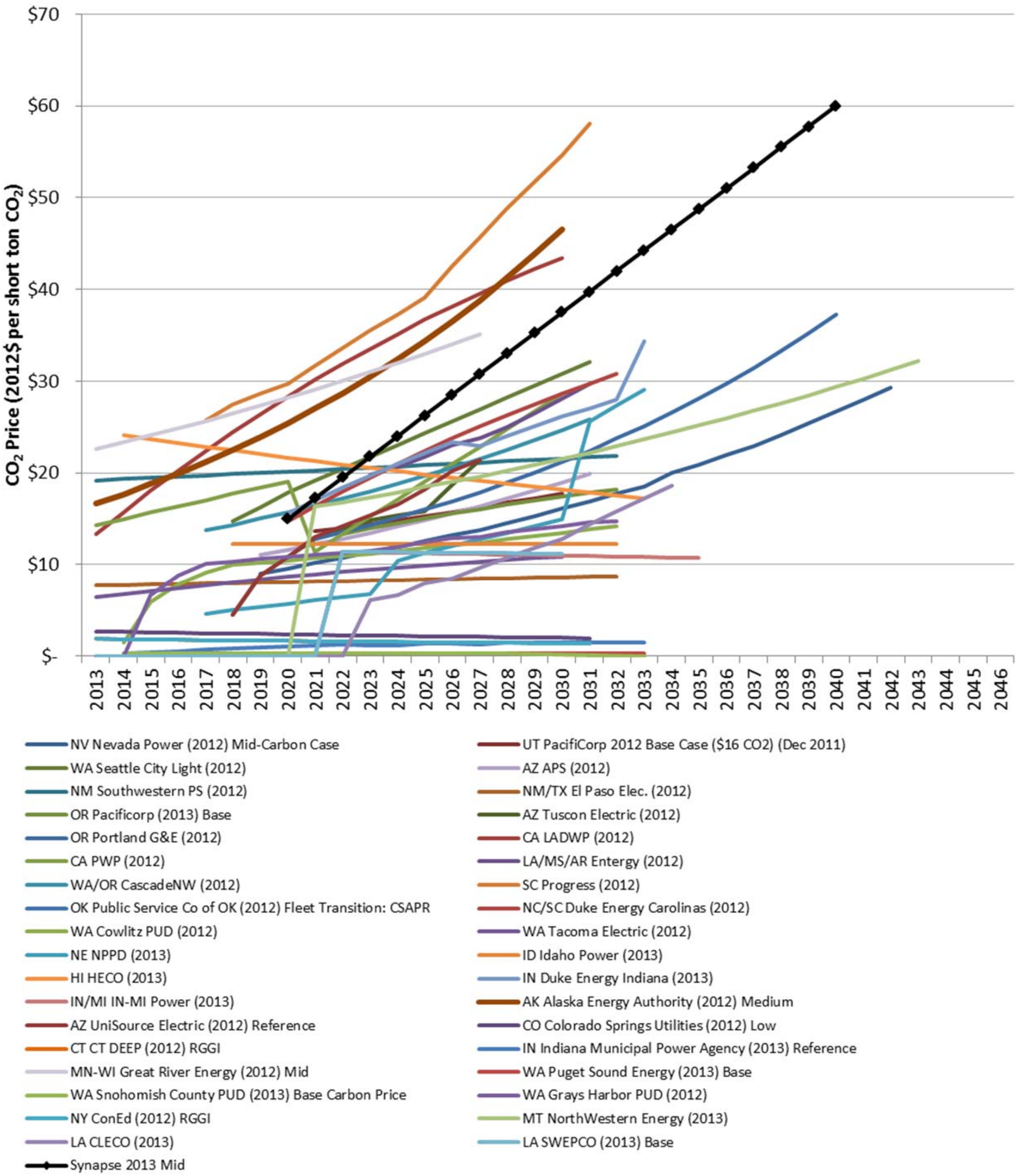
- The **Low case** forecasts a carbon price that begins in 2020 at $10 per ton, and increases to $40 in 2040, representing a $22 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies—either regulatory or legislative—exist but are not very stringent.
- The **Mid case** forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $60 in 2040, representing a $34 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals.
- The **High case** forecasts a carbon price that begins in 2020 at $25 per ton, and increases to approximately $90 in 2040, representing a $52 per ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect

of raising carbon prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

These price trajectories are designed for planning purposes, so that a reasonable range of emissions costs can be used to investigate the likely costs of alternative resource plans. We expect an actual CO_2 price to fall somewhere between the low and high estimates throughout the forecast period.

In Figure 5, the Synapse Mid forecast is shown in comparison to the reference case utility forecasts presented earlier. See Appendix A for comparisons to utilities' Low and High case forecasts.

Figure 5: Synapse Mid Forecast Compared to Recent Utility Reference Case Forecasts



In Figure 6, the Synapse forecasts are compared to the carbon price used in federal rulemaking. While the federal price starts out higher in 2020, the Synapse Mid forecast approaches this value at the end of the projected period.

Figure 7 compares the Synapse forecasts for 2020 to several of the sources identified in this report: the carbon price used in federal rulemakings, EMF 24 study results, and recent utility forecasts. The high and low ends of these sources span a wide range, but the central (mean) values show less variation. The Federal Carbon Price for Rulemakings shows a particularly large spread resulting from different choices in the assumed discount rate. Similarly, some EMF models show a zero carbon price in 2020, implying the country can get to 17 percent below 2020 based on technology improvement and other existing policies. Other models have substantially higher prices, perhaps resulting from more growth in energy consumption in the reference (no policy) case.

Figure 6: Synapse Forecast Compared to Carbon Price Used in Federal Rulemakings

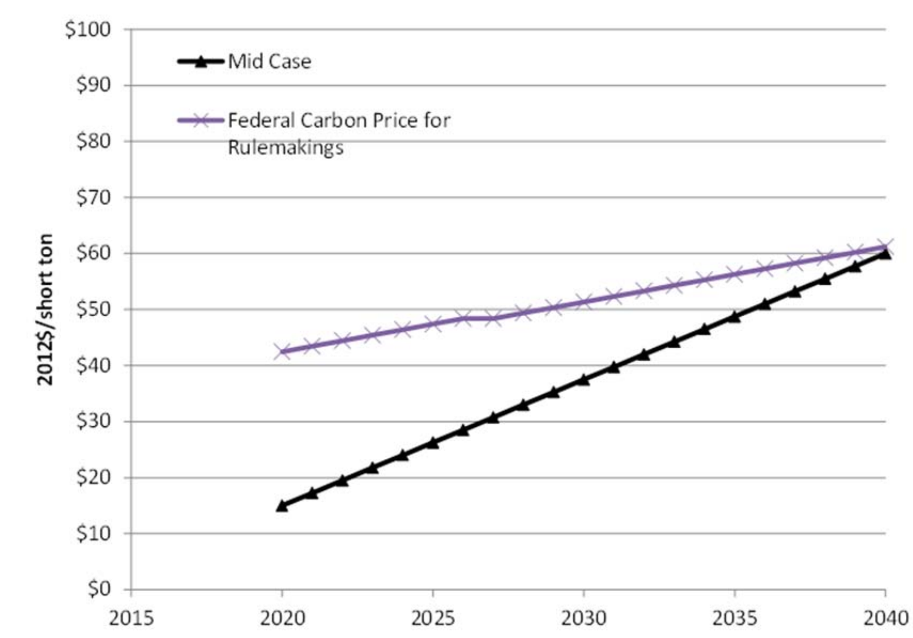
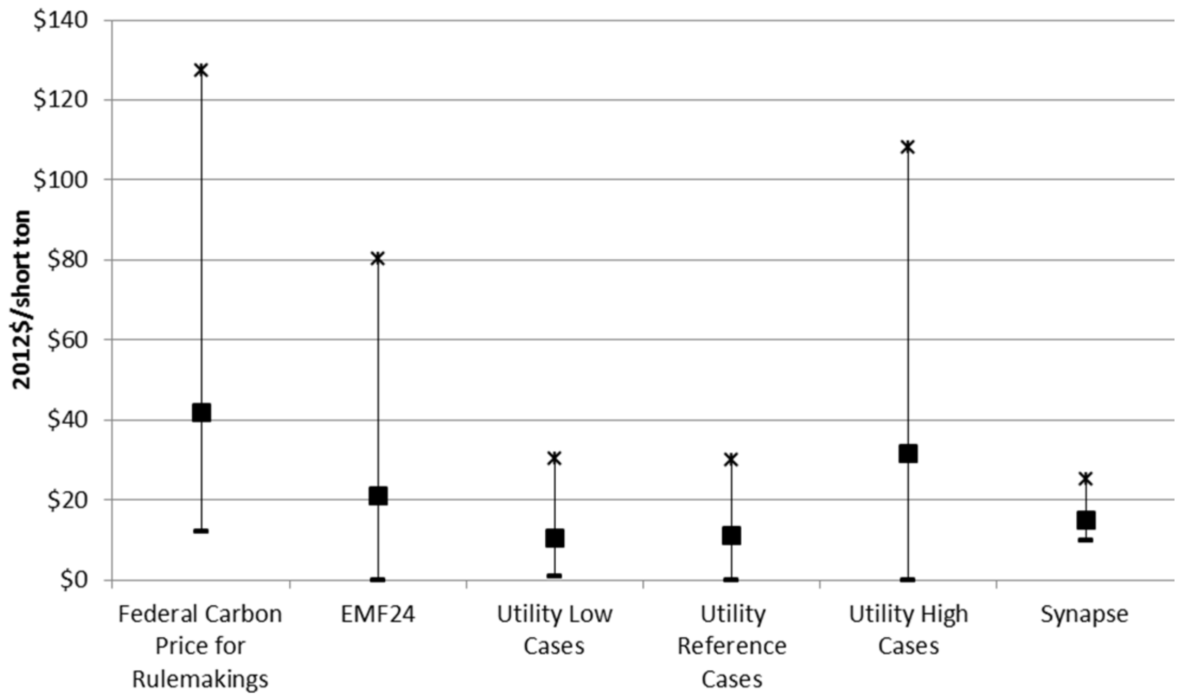


Figure 7: Synapse CO_2 Forecasts for 2020 Compared to Other Sources



11. Appendix A: Synapse Forecast Compared to Utility Forecasts

Figure 8: Synapse CO2 Price Forecast Compared to Recent Utility Low-case Forecasts

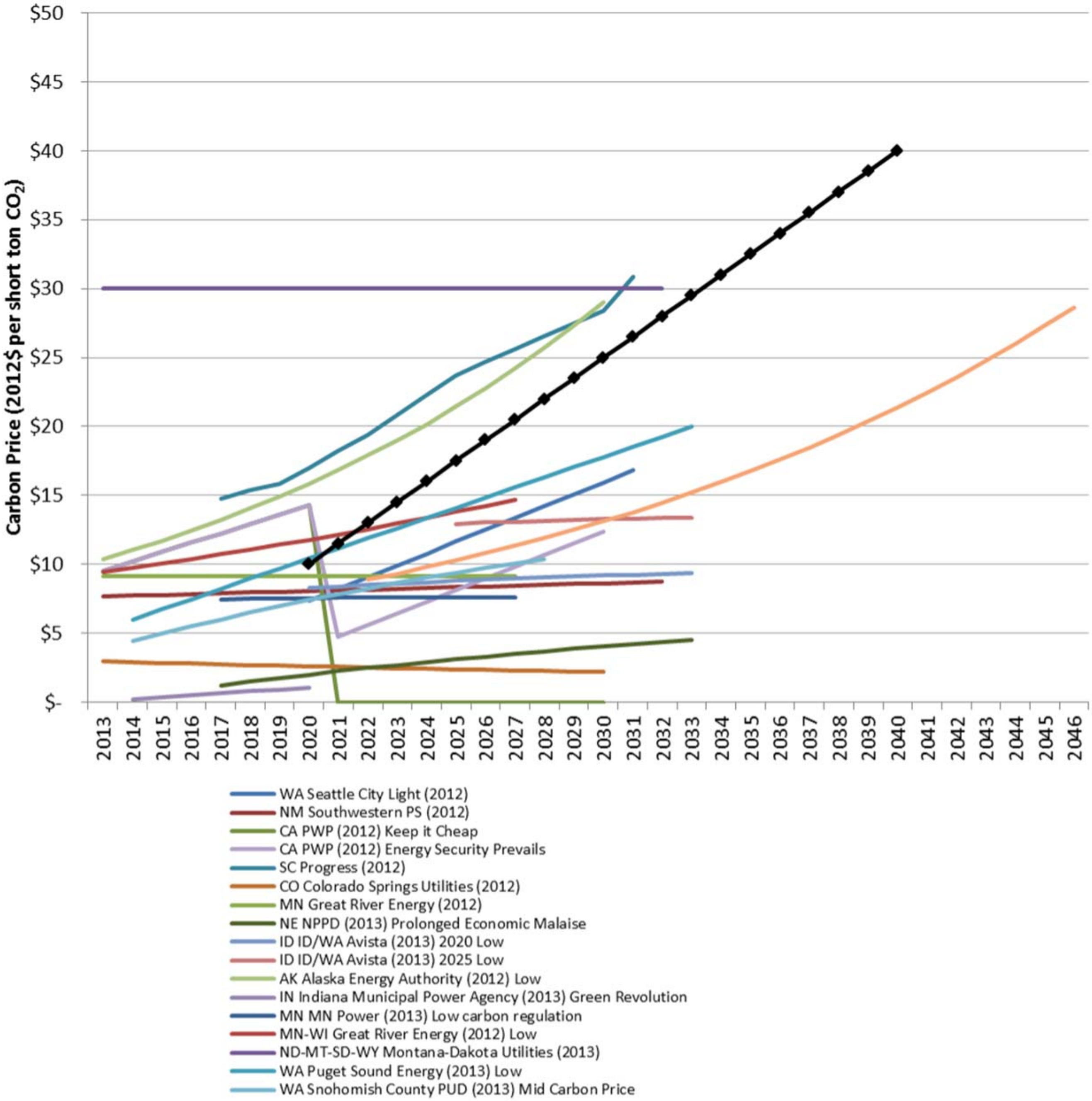


Figure 9: Synapse CO2 Price Forecast Compared to Recent Utility High-case Forecasts

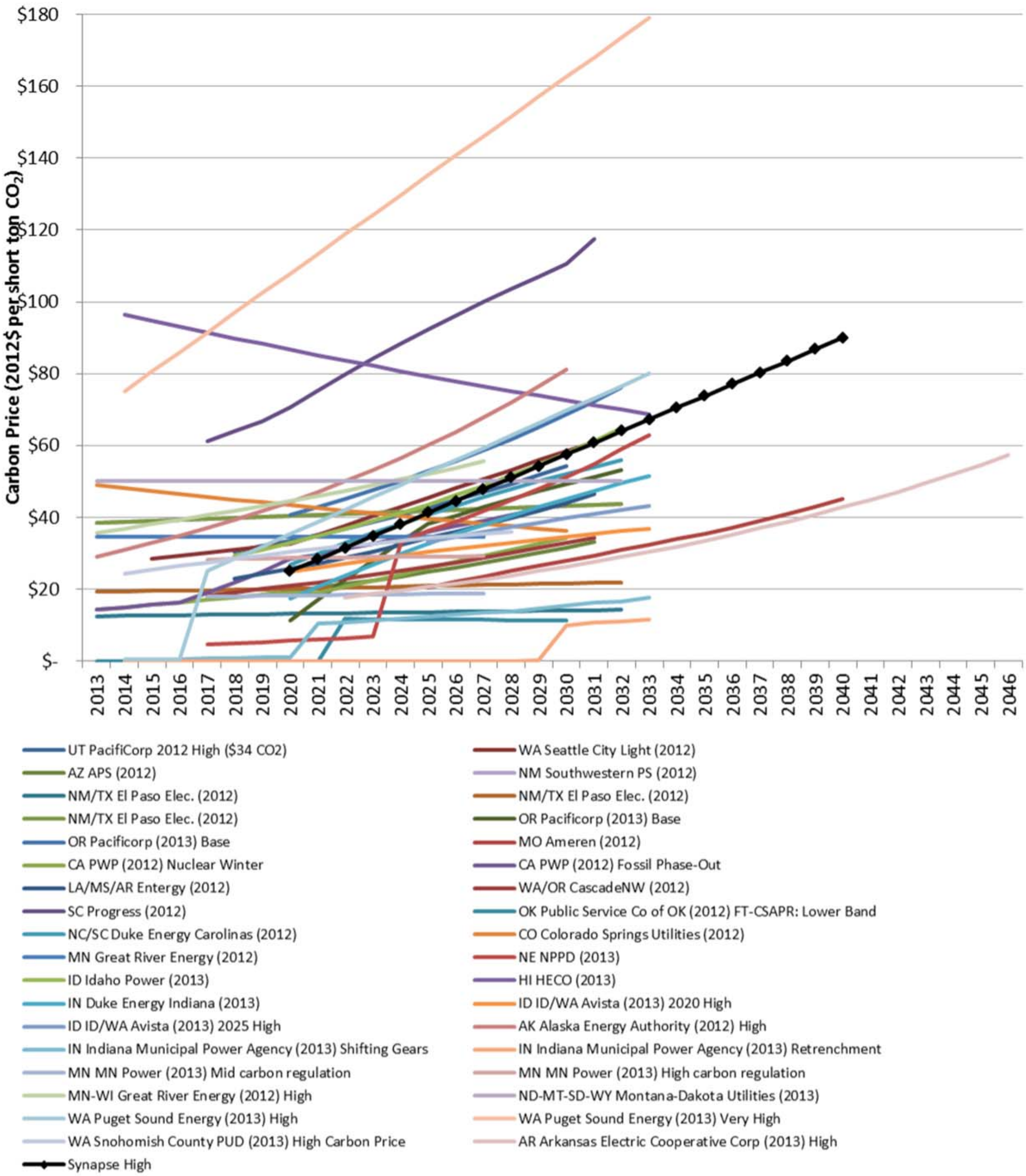
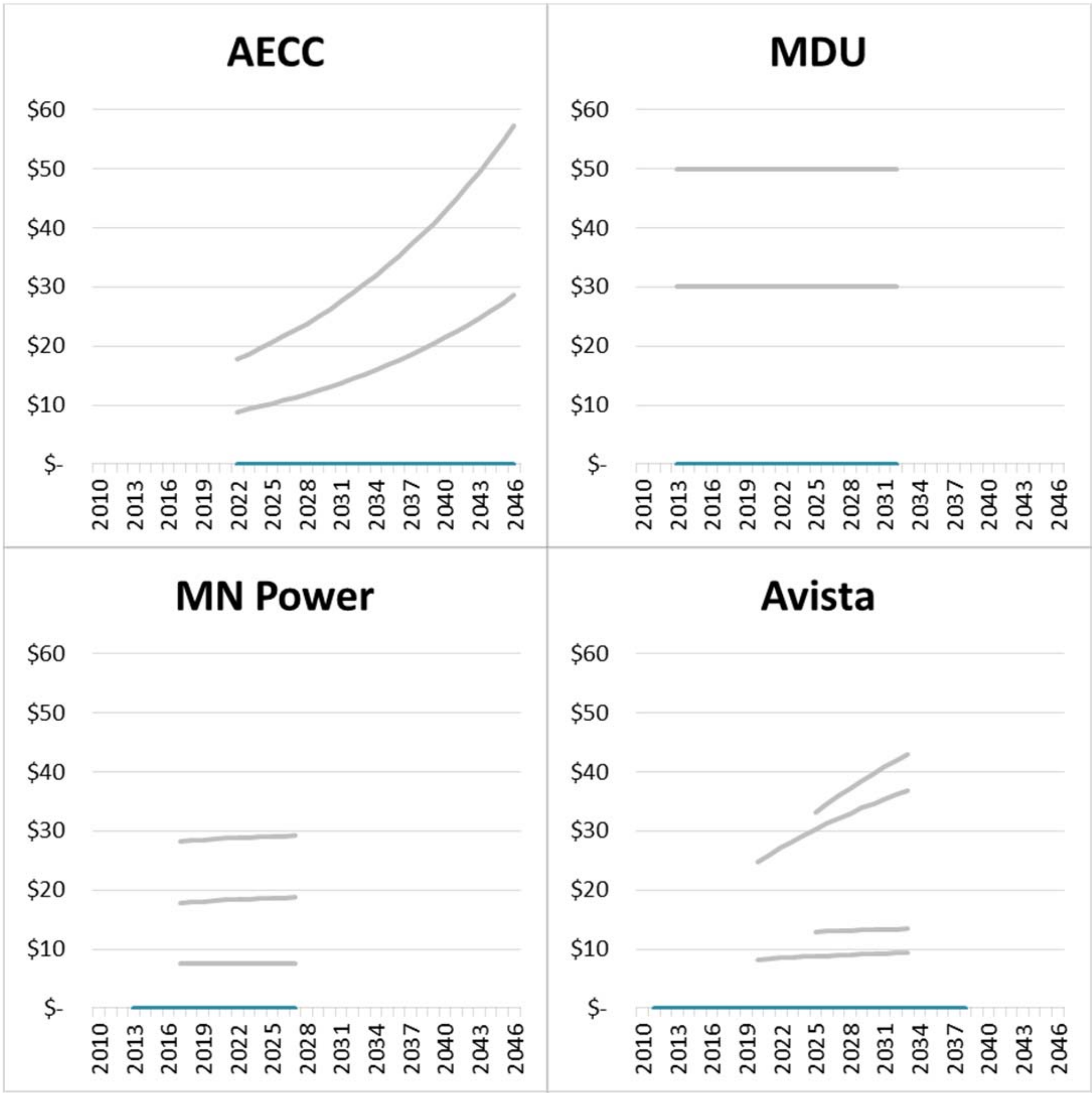


Figure 10: Range of CO_2 Price Scenarios for Utilities with $0 Reference Cases (2012$/short ton)



Note: Reference forecasts are presented in blue. All other sensitivities are in grey.

THE OKLAHOMA ATTORNEY GENERAL'S PLAN

The Clean Air Act Section 111(d) Framework that Preserves States' Rights

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State of Oklahoma
April 2014

I. Executive Summary

President Obama's Climate Action Plan (CAP) directed the Environmental Protection Agency ("EPA" or the "Agency") to regulate carbon dioxide (CO_2) emissions from new and existing fossil-fuel fired generation units. The CAP has no legal basis or force of law, and EPA in regulating these units remains subject to the Clean Air Act (CAA) – a law passed by Congress and signed by the President consistent with principles of democratic governance. EPA is unlawfully regulating through and to the principles outlined in the CAP, and in doing so is engaging in energy rationing that will first eliminate coal-fired generation from each State's fuel mix, then target and eradicate natural gas-fired generation.

EPA has proposed a New Source Performance Standard (NSPS) for new power plants, which includes performance standards that are not achievable in the real world. Even more problematic, pursuant to Section 111(d) of the CAA, EPA will issue standards for existing power plants mid-year 2014 that will create immediate problems and higher electricity costs for consumers nationwide, including in Oklahoma. Because the existing generation fleet was neither built nor designed to control CO_2 emissions, the EPA approach will seek to set a State by State budget using a baseline for allowed emissions resulting from electricity generation in each state. However, EPA's ambition is restrained by Section 111(d), which gives the States the authority to determine achievable emission standards for its fossil-fuel fired units. Despite President Obama's directives to EPA in the Climate Action Plan, EPA cannot exceed its legal authority under Section 111(d). The CAA governs EPA's actions – not the CAP. Furthermore, the legality of EPA's purported authority to regulate CO_2 emissions for existing power plants under Section 111(d) has been questioned, and the Agency's very ability to promulgate regulations is only assumed to be legal here for purposes of this discussion.

The Oklahoma Attorney General's Plan ("OKAG Plan") counters the recently released white paper entitled *Greenhouse Gas Implications for Kentucky under Section 111(d) of the Clean Air Act* (Kentucky Plan)[1], which promotes a "mass-emissions" approach – conceptually indistinguishable from cap-and-trade. This approach removes the significant authority and discretion left to the States under Section 111(d); instead, it embraces CAP-driven energy rationing, despite the fact that there is no legal basis for the CAP. The Kentucky Plan's proposed framework erroneously gives EPA maximum flexibility with its Section 111(d) authority and minimum flexibility to the States in crafting emission standards. This is the antitheses of the Section 111(d) regulatory scheme.

The Kentucky Plan borrows from environmental and academic literature that argues for the wholesale shift of Section 111(d) into a national cap-and-trade regime. A Natural Resources Defense Council (NRDC) white paper argues for constraints on emissions of carbon under Section 111(d) as part of an "optimization process," which will be specified on the basis of "cap-

[1] Commonwealth of Kentucky Energy and Environment Cabinet, *Greenhouse Gas Policy Implications for Kentucky under Section 111(d) of the Clean Air Act* (Oct. 2013), *available at* http://eec.ky.gov/Documents/GHG%20Policy%20Report%20with%20Gina%20McCarthy%20letter.pdf.

and-trade policies" and applied to individual generating units or groups of units.[2] Academic papers argue for using Section 111 to implement a cap-and-trade program to drive Greenhouse Gas (GHG) emission reductions, even if that means "jamming a square peg through a round hole."[3]

The OKAG Plan properly construes Section 111(d): EPA designs a procedure and emission guidelines, and States determine the legally enforceable emission standard that is as stringent as the applicable guideline – *unless* the State determines that circumstances justify imposition of a less stringent emission standard. The OKAG Plan institutes a unit-by-unit, "inside the fence" approach to determining State emission standards, and accounts for the practical reality that air quality impacts differ from State to State, as do costs and opportunities for CO_2 emission reductions. With the OKAG Plan, the resource planning function is *not* usurped by an allocation system or CO_2 budget and instead remains where it belongs – "inside the fence" in the hands of state regulators with specialized expertise and a focus on ratepayer impacts and protection of the public interest. Furthermore, the "inside the fence" model ensures that emissions reductions are limited to the engineering limits of each facility. The OKAG Plan preserves State primacy and does not turn over management of local generation fleets to EPA under the guise of "flexibility."

II. Background and Regulatory Concerns

The EPA is poised to again propose new regulations that venture well beyond the limits of the law. Through the recent CAP, which has no force of law or legal basis, President Obama has called upon EPA to propose CO_2 emission guidelines for existing power plants by June 1, 2014, and to finalize those rules by June 1, 2015 under Section 111(d).[4] Accordingly, individual States[5], such as the State of Kentucky, have begun offering proposed "frameworks" to provide "input" to EPA in developing guidelines under Section 111(d). The OKAG Plan serves as a counterproposal that is more faithful to the law as written; gives States the significant discretion and authority reserved to them under Section 111(d); and keeps the EPA from dictating standards it has no authority to impose. It properly leaves the appropriate amount of emissions reductions to the State on an "inside the fence" basis.

Simply put, EPA does not have the authority to impose a state-by-state "cap and trade" CO_2 emissions policy.. This "outside the fence" approach ignores the States' primary authority to devise Section 111(d) State Implementation Plans (SIPs) that are: flexible; cognizant of the

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[2] *See, e.g.*, Daniel A. Lashof, Starla Yeh, David Doniger, Sheryl Carter & Laurie Johnson, *Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters*, Natural Res. Def. Council (Dec. 2012), *available at* http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf.
[3] James Salzman & Barton H. Thompson, Jr., Environmental Law and Policy 87-88 (3d ed. 2010); *see also*, M. Rhead Enion, *Using Section 111 of the Clean Air Act for Cap-and-Trade of Greenhouse Gas Emissions: Obstacles and Solutions*, 30 UCLA J. Envtl. L. & Pol'y 1, 34-45 (2012).
[4] 42 U.S.C. § 7411(d).
[5] On December 16, 2013, officials from 15 states submitted a paper entitled *States' §111(d) Implementation Group Input to EPA on Carbon Pollution Standards for Existing Power Plants* to EPA. *See* Mary D. Nichols, et al., *States' §111(d) Implementation Group Input to EPA on Carbon Pollution Standards for Existing Power Plants*, (Dec. 16, 2013) *available at* http://www.georgetownclimate.org/sites/default/files/EPA_Submission_from_States-FinalCompl.pdf.

particular circumstances of the given state; and will not imperil the families and businesses of the state with ruinous electricity rate increases.

i. EPA has, at best, circumscribed authority under Section 111(d).

EPA's authority to promulgate a CO_2 emission guideline for *existing* electric generating units (EGUs) has been questioned.[6] CO_2 is not among the types of pollutants that can be regulated explicitly under Section 111(d). Therefore, EPA has no authority *at all* to require States to adopt CO_2 performance standards for existing EGU CO_2 emissions.[7] Despite our belief that EPA has no authority to promulgate a CO_2 emission guideline for existing EGUs, it is clear that EPA believes that it has that authority and will attempt to exercise it.[8] In line with EPA's anticipated action claiming CO_2 emission authority, the OAG Plan at least strikes the appropriate balance on the "cooperative federalism" scale, emphasizing State primacy under Section 111(d) of the Clean Air Act.

Unchecked, EPA will continue to implement regulations that exceed its statutory authority to the detriment of the States. Under the CAA, Congress has vested authority to the States, whose citizenry and businesses ultimately pay the price of costly and ineffective regulations. EPA's authority under the Section 111(d), at best, is limited to developing a procedure for States to establish emissions standards for existing sources.

Indeed, Section 111(d) materially differs from Section 111(b), the NSPS provision, and it is well-established that **"Section 111(d) grants a more significant role to the states in development and implementation of standards of performance than does [Section] 111(b)."**[9] The Supreme Court itself recognizes the extensive State authority under Section

[6] *See* William J. Haun, The Clean Air Act as an Obstacle to the Environmental Protection Agency's Anticipated Attempt to Regulate Greenhouse Gas Emissions from Existing Power Plants, THE FEDERALIST SOCIETY (Mar. 2013), *available at* http://www.fed-soc.org/publications/detail/the- clean-air-act-as-an-obstacle-to-the-environmental-protection-agencys-anticipated-attempt-to-regulate-greenhouse- gas-emissions-from-existing-power-plants.

[7] EPA's proposed CO_2 NSPS rule for new EGUs pursuant to Clean Air Act (CAA) Section 111(b) is a separate matter, under a separate section of the Clean Air Act.

[8] Section 111(d) does not authorize EPA to adopt regulations for a particular category of facilities where that source category "is regulated under section [112] of this title." *See* 42 U.S.C. § 111(d)(1)(A)(i). Indisputably, coal plants are regulated under Section 112. EPA listed coal plants for regulation under Section 112 in 2000 and recently established Section 112 pollution standards in its 2012 Mercury and Air Toxics Standards (MATS) rule. *See* 77 Fed. Reg. 9304 (Feb. 16, 2012); 65 Fed. Reg. 79,825 (Dec. 20, 2000). Thus, having regulated coal plants under Section 112, EPA has no power under Section 111(d) to adopt regulations governing coal-plant CO_2 emissions. Because EPA has not yet proposed Section 111(d) CO_2 performance standards for existing coal plants, EPA's exact rationale for its authority to do so is not known with certainty. Nevertheless, based on past EPA statements, EPA is expected to claim that Section 111(d) is ambiguous on this point and that its interpretation of the provision as allowing for CO_2 regulation is entitled to deference. The claimed ambiguity stems from language in the House and Senate versions of the 1990 Clean Air Act Amendments. But as has recently been explored at length, EPA's interpretation depends on not giving effect to all of the language Congress adopted. *See* Haun, *supra* note 2. Including all of Congress' language inevitably leads to the conclusion that CO_2 emissions from coal-fueled EGUs cannot be regulated under Section 111(d). *See, e.g.,* Brian H. Potts, *The President's Climate Plan for Power Plants Won't Significantly Lower Emissions*, 31 YALE J. ON REG. 1A, 9A (2013)(concluding in part that "it is highly questionable whether EPA can even regulate existing power plants at all using Section 111(d).")

[9] Jonas Monast, Tim Profeta, Brooks Rainey Pearson, and John Doyle, *Regulating Greenhouse Gas Emissions From Existing Sources: Section 111(d) and State Equivalency*, 42 ENVTL. L. 10206, 10206 (2012).

111(d); Section 111(d) allows "each State to take the first cut at determining how best to achieve EPA emissions standards within its domain."[10]

The cornerstone of the OKAG Plan is State primacy under the CAA. The way in which EPA has overreached in interpreting its legal authority under the CAA to promulgate a NSPS for *new* EGUs portends a similarly aggressive and unlawful approach to the Section 111(d) regulation of *existing* EGUs. EPA's unambiguous policy goal in establishing its new source standards is to prevent the construction of new fossil-fuel fired plants. For example, EPA's proposed EGU NSPS would foreclose the construction of new coal-based electric generation absent carbon capture and storage (CCS), yet CCS is likely to remain commercially infeasible for a decade or more. The elimination of coal as a fuel for new electric generation would have severe implications for electricity prices; the economy and job-creation in general; and the competitiveness of American manufacturing. Importantly, States that have already eliminated or reduced coal-fired generation or have planned or carried out turnover of their generation fleet to natural gas are not immune from Section 111(d). Under these circumstances, gas plant emissions will be the first target for emission reduction – and the result is the same: elimination of gas as a generating resource. The eradication of all fossil-fueled generation, *including natural gas*, is the inevitable result of EPA's current course of action over time and will only be counteracted when States assert their statutory authority through proper balance and implementation of a Section 111(d) SIP.

ii. The Kentucky Plan.

Even though it says all the right things, the Kentucky Plan does not strike the proper balance in its proposed framework. It references the "flexibility" provided to the States under Section 111(d); recognizes the fact that States "submit a plan to establish standards of performance"; argues that CCS "is not yet commercially proven in the primary large-scale for which it is envisioned"; and argues that "the transition to lower emission sources should not be a sole trade-off between one type of carbon fuel (coal) for another (natural gas)." Unfortunately, by advocating for a "mass-emissions approach," the Kentucky Plan in practice does not support these statements.

The Kentucky Plan provides a framework centered on mass emissions, or an emission cap, which would result in standards "expressed as a percent reduction of the mass (tons) of pollutant (CO_2)." The framework is not tied to an emission standard based upon adequately demonstrated and achievable systems of emission reductions; rather, the Kentucky Plan predefines its goal and regulates to the lawless CAP by setting an emission baseline and mandating CO_2 reduction levels for 2020 (17 percent), 2025 (28 percent), 2030 (38 percent), and 2050 (80 percent). This involves no unit-by-unit analysis of achievable reductions or consideration of whether emission reduction technologies are adequately demonstrated. It simply sets a cap then forces compliance, divesting the States of their significant discretion and authority under Section 111(d).

[10] *Am. Elec. Power Co. v. Connecticut*, 131 S. Ct. 2527, 2539 (2011). The Court further recognized that EPA merely promulgates guidelines, while States determine performance standards: "For existing sources, EPA issues emissions guidelines; in compliance with those guidelines and subject to federal oversight, the States then issue performance standards for stationary sources within their jurisdiction, § 7411(d)(1)." *Id.* at 2537-38.

The "mass-emissions approach" is legally tenuous and *will* result in wholesale turnover of the generation fleet at ratepayer expense through the mandated CO_2 reductions. Indeed, the threat posed by the significant reductions contemplated by the Kentucky Plan is not limited to coal and equally portends drastic reductions in natural gas-fired generation. The Kentucky Plan threatens all fossil-fuel fired generation and in turn the economic recovery and ratepayers because diverse resource portfolios keep risk low and reliability high.

iii. States are the driver of Section 111(d) regulation, and the OKAG Plan recognizes this authority.

States, and not EPA, have primary authority over Section 111(d) planning. Resource planning will have to comply with state-created and -implemented plans for CO_2 reductions. Properly construed Section 111(d) SIPs will require achievable reductions, not wholesale turnover of the generation fleet. In fact, Section 111(d) explicitly recognizes cost, and States have flexibility to keep low cost generation running.[11]

The OKAG Plan offers an alternative framework that is consistent with the State primacy entrenched in Section 111(d). As contemplated by Section 111(d), States possess the authority and discretion to define emission reduction requirements through unit-specific analyses. The OKAG Plan eschews the mass-emissions model because this approach subsumes resource planning processes traditionally left to the States into mandatory CO_2 budgets. Instead, the OKAG Plan allows for a unit-by-unit analysis and considers affordable electricity.. In addition, the framework holds EPA to its recent public pronouncements regarding regulation of existing EGUs. In a December 2, 2013 speech before the Center for American Progress, EPA Administrator Gina McCarthy pledged that EPA would be "really flexible" with States regarding Section 111(d).[12] The OKAG Plan embraces the "significant flexibility" left to the States under Section 111(d).

III. The Statutory and Regulatory Framework For Developing Performance Standards For Existing Sources

i. Emission guidelines versus emission standards and EPA's confined authority to promulgate a "guideline document."

The difference between EPA and State authority in the Section 111(d) regulatory framework is illustrated by the difference between an "emission guideline" and an "emission standard." An emission guideline must reflect emissions reduction achievable by "the best system of emission reduction (taking into account the cost of such reduction) … [that] has been adequately demonstrated for designated facilities."[13] Promulgation of a "guideline" is consistent with EPA's statutory duty to "establish a procedure" for State submission of Section 111(d)

[11] *See, e.g.* 40 C.F.R. § 60.24(f)(1) (providing that States may provide for less stringent emissions standards based on "[u]nreasonable cost of control resulting from plant age, location or basic process design ….")
[12] *See* Laura Barron-Lopez, EPA to be 'flexible' on carbon standards, The Hill (Dec. 2, 2013), *available at* http://thehill.com/blogs/e2-wire/e2-wire/191743-epa-to-be-flexible-with-states-on-carbon-standards.
[13] 40 C.F.R. § 60.21(e).

SIPs.[14] Guidelines may be established for different types, sizes and classes of facilities if costs of control, physical limitations, geographic locations or similar factors render sub-categorization appropriate.[15] Under Section 111(d) regulations, EPA's guideline document is meant to "provide information for the development of State plans."[16]

The definition of an "emission standard" is indicative of the States' more substantive role. An emission standard is a "*legally enforceable regulation* setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions."[17] Each SIP must include emission standards, and "emission standards shall be no less stringent than the corresponding emission guideline(s)."[18] However, States retain the discretion to prescribe *less stringent* emissions standards under certain circumstances, including if the cost of control is "unreasonable … resulting from plant age, location, or basic process design."[19]

In sum, a guideline is general and suggestive, while a standard is specific and prescriptive – and the Section 111(d) implementing regulations reflect this difference. EPA designs a procedure and emission guidelines, and States determine the legally enforceable emission standard that is as stringent as the applicable guideline – *unless* the State determines that circumstances justify imposition of a less stringent emission standard after evaluating the factors set forth at 40 C.F.R. § 60.24(f). More simply, the standard must satisfy the guideline unless enumerated circumstances, *in the States' estimation*, exist. This invokes the principle of cooperative federalism, with roles clearly delineated for both EPA and the States. The cooperative federalism principle is illustrated by EPA's general procedural regulations relating to the States' adoption and submittal of SIPs, while the State-driven SIPs establish the legally enforceable emission standards for existing sources. EPA may only promulgate legally enforceable emission standards if (1) a State fails to submit a SIP, or (2) a State submits a SIP that does not comply with Section 111(d) regulations.

ii. States have primacy and discretion in formulating Section 111(d) plans.

As discussed above, States have significant discretion in formulating Section 111(d) SIPs. Although the "emission standards" are to be "no less stringent than the corresponding emission guideline(s)," the States may make a case-by-case determination that a specific facility or class of facilities are subject to a less-stringent standard or longer compliance schedule due to: (1) cost of control; (2) a physical limitation of installing necessary control equipment; and (3) other factors making the less-stringent standard more reasonable.[20] Moreover, States may

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[14] 42 U.S.C. § 7411(d)(1).
[15] 40 C.F.R. § 60.22(b)(5).
[16] 40 C.F.R. § 60.22(b). Section 111(d) requires the existence of a performance standard for new sources as a condition precedent to the development of such standards for existing sources. Thus, the legality of the final version of EPA's EGU NSPS rule has significant implications for EPA's ability to require regulation of existing EGUs.
[17] 40 C.F.R. § 60.21(f) (emphasis added).
[18] 40 C.F.R. § 60.24(c).
[19] 40 C.F.R. § 60.24(f).
[20] 40 C.F.R. § 60.24(f).

establish equipment specifications rather than emissions rates where allowable emission rates are "clearly impracticable."[21]

EPA's authority, on the other hand, is limited to evaluating compliance with the guideline document and not promulgating and implementing substantive performance standards. After submittal of a SIP, EPA has four months to determine whether the plan meets the requirements discussed above. If EPA disapproves the plan, the State may correct the deficiencies or, under EPA's construction, the Agency may issue its own plan within six months of the original submission deadline.[22]

iii. Systems of emissions reduction must be adequately demonstrated.

Fundamentally, Section 111(d) requires that emission reductions be achievable through adequately demonstrated systems of emission reduction technology. Under Section 111(d), EPA establishes procedures for States to submit plans containing "performance standards." The term "standard of performance" is defined in Section 111(a):

> The term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health environmental impact and energy requirements) the Administrator determines *has been adequately demonstrated*.[23]

EPA's guideline document must "reflect[] the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated."[24] The crux of this requirement thus is that the emission reduction system be, in fact, adequately demonstrated.

Specifically with regard to coal plants, States and EPA have limited options in determining systems of CO_2 emission reduction that have been adequately demonstrated as achievable. EPA itself has acknowledged on several occasions that CCS would not qualify as a performance standard for existing coal plants. The only way to achieve cost-effective emission reductions for a coal generator would be to improve the efficiency of the unit, since increased efficiency translates into reduced CO_2 emissions per unit of electric output. Existing coal plants differ widely in terms of the combustion technologies they use, their ages, maintenance histories,

[21] 40 C.F.R. § 60.24(b)(1).
[22] 40 C.F.R. § 60.27(c)-(d). The State of North Carolina, through the North Carolina Department of Environment and Natural Resources, recently submitted a policy paper entitled "North Carolina §111(d) Principles" to EPA. Given the certain litigation regarding Section 111(d), coupled with recent vacations by the D.C. Circuit and other courts of key EPA rules, North Carolina believes that "EPA should require each State to submit a §111(d) plan within three years following the expiration of the legal litigation process – a 'legal trigger approach.'" The Oklahoma Attorney General's Plan also advocates for this approach because it will protect States from allocating limited resources to comply with another rule that is ultimately vacated by the courts. *See* North Carolina Department of Environment and Natural Resources, *North Carolina §111(d) Principles*, at 14. (Jan. 27, 2014), *available at* http://www.ncair.org/rules/EGUs/NC_111d_Principles.pdf.
[23] 42 U.S.C. § 7411(a) (emphasis added).
[24] 40 C.F.R. § 60.22(b)(5).

and how they operate. There is no "one-size-fits-all" method of improving unit efficiency that would apply to all units in the coal fleet. As a result, CO_2 performance standards must be based on unit-by-unit evaluations of available cost-effective efficiency. This approach, which is grounded squarely in the language and history of the Section 111 program, would not require coal plants to retire or curtail operation; they would only require more efficient operation, to the extent it is cost-effective to do so.

EPA's current approach regarding CCS is cause for grave concern. In the recently proposed CO_2 NSPS for new sources, EPA contends that CCS technologies have been adequately demonstrated; however, this conclusion conflicts with existing law, specifically the Energy Policy Act of 2005 (EPAct). EPA maintains that CCS technologies for coal-fired power plants have been "adequately demonstrated" based on three government-funded projects receiving assistance under the Department of Energy's Clean Coal Power Initiative (CCPI) and a fourth project funded by the Canadian government. EPA Acting Assistant Administrator Janet McCabe confirmed the Agency's use of these projects as the basis for its determination at a November 14, 2013 hearing. The EPAct prohibits EPA from considering technology used at CCPI projects as being "adequately demonstrated" for purposes of Section 111(d). This legal issue was raised with EPA in a November 15, 2013 letter to Administrator McCarthy from Congressman Fred Upton (R-MI), the chairman of the House of Representatives Committee on Energy and Commerce, and other legislators; the committee leaders ultimately concluded that "[u]nder these provisions of the Energy Policy Act of 2005, EPA's consideration of CCPI projects to determine that CCS for coal-fired power plants is 'adequately demonstrated' is prohibited." The Office of Management and Budget within the Obama Administration raised similar concerns: "EPA's assertion of the technical feasibility of carbon capture relies heavily on literature reviews, pilot projects, and commercial facilities yet to operate. We believe this cannot form the basis of a finding that CCS on commercial-scale power plants is 'adequately demonstrated.'"[25]

A working group within EPA's Science Advisory Board (SAB) also raised concerns with EPA's conclusion that CCS has been adequately demonstrated.[26] The working group concluded "that the scientific and technical basis for carbon storage provisions is new science and the rulemaking would benefit from additional review"[27]; it necessarily follows that new science is

[25] EPA, *Summary of Interagency Working Comments on Draft Language under EO12866 Interagency Review*, at 9 (Aug. 19, 2013), *available at* http://www.eenews.net/assets/2014/02/04/document_daily_02.pdf. The Center for Regulatory Effectiveness has also raised concerns about compliance with the Data Quality Act. *See* Letter from Jim J. Tozzi, Center for Regulatory Effectiveness, to Administrator Gina McCarthy, EPA (Feb. 3, 2014), *available at* http://www.eenews.net/assets/2014/02/04/document_daily_01.pdf.

[26] Memorandum from SAB Work Group on EPA Planned Actions for SAB Consideration of the Underlying Science to Members of the Chartered SAB and SAB Liaisons, Nov. 12, 2013, *available at* http://yosemite.epa.gov/sab/sabproduct.nsf/18B19D36D88DDA1685257C220067A3EE/$File/SAB+Wk+GRP+Memo+Spring+2013+Reg+Rev+131213.pdf. The memorandum's findings regarding the existing basis for the conclusion that CCS has been adequately demonstrated as achievable is equally troubling: "The EPA has stated that U.S. Department of Energy National Energy Technology Laboratory (NETL) studies as well as existing EGUs under construction and in advanced stages of development were used as the basis for the BSER assumptions for new natural gas and coal fuel sources for new EGUs. EPA staff explained that the NETL studies were all peer reviewed and EPA did not conduct additional peer review(s). *However, based on additional information provided to the Work Group from NETL, the peer review appears to be inadequate*." *Id.* (emphasis added).

[27] *Id.*

not established science. In a recent meeting, however, an EPA official argued that CCS does not require SAB peer review because the proposed new NSPS rule *does not cover how CO2 emissions are stored* and instead the rule only covers the control technology. In other words, the CCS conclusion does not include the "storage" component of CCS. The notion that storage is not legally relevant to the NSPS is illogical.[28]

Natural gas is similarly threatened by EPA overreach regarding "adequately demonstrated" emission control technologies. If the EPA determines CCS is "adequately demonstrated" as achievable and the practical effect is the mass closure of coal plants, only natural gas emissions remain to achieve reductions to comply with Section 111(d). The unachievable technologies will influence the emission baseline that is set, and natural gas will be eliminated from the resource mix through the incremental reductions.

These significant concerns compel the proposal of the OKAG Plan framework. The proposed framework contemplates States and the EPA working together, but it also requires good faith and legal action on the part of the Agency. The issues discussed above, particularly the CCS adequate demonstration conclusion, merits further involvement of and discussion with the States and other stakeholders.

IV. The Kentucky Plan – State Cap and Trade

The Kentucky Plan is tethered to three improper premises, specifically that: (1) EPA effectively dictates performance standards; (2) allowance systems are permissible as an "emission standard"; and (3) fossil-fuel fired EGUs should account for the bulk of CO_2 emissions reduction. It amounts to express or de facto cap and trade. These deficiencies underscore the need for a unit-by-unit, State-driven plan like the OKAG Plan.

First, Section 111(d) implementing regulations provide that each State compliance plan shall include emission standards and compliance timelines, *as determined by each State*.[29] This is consistent with the text of Section 111(d) itself, which provides that States shall establish "standards of performance for any existing source …."[30] The Kentucky Plan misappropriates authority under Section 111(d) and precludes the extensive role and authority given to the States under Section 111(d).

Second, the Kentucky Plan makes clear that the "proposed framework sets a statewide mass-emission limit that could be the foundation for an allocation program." In other words, the mass-emissions model appears solely based on the use of an "allowance system" under the regulations. The regulatory definition of "emission standard" appears at 40 C.F.R. § 60.21(f) and includes the term "allowance system," and this term appears later in the implementing regulations at 40 C.F.R. § 60.24(b)(1). Notably, the term "allowance system" did not appear in these regulations when promulgated by EPA in 1975; rather, it was added 30 years later in 2005

[28] North Carolina raises similar concerns and "does not believe that CCS is 'adequately demonstrated' for purposes of 111(d)." It further states that "sound science, rather than speculation, should be relied upon to develop §111(d) emission guidelines and plans." *See* North Carolina Department of Environment and Natural Resources, *North Carolina §111(d) Principles*, at 12-13.
[29] 40 C.F.R. § 60.24(a)-(b)
[30] 42 U.S.C. § 7411(d)(1).

when EPA promulgated the Clean Air Mercury Rule (CAMR) because the CAMR featured a mercury allowance trading program.[31] The CAMR changes to these regulations included a new subparagraph (k) at 40 C.F.R. § 60.21, this established a new definition for the term "allowance system." However, the D.C. Circuit Court of Appeals vacated the CAMR regulations in 2008.[32] Despite the ruling, no change was made to the regulations until 2012 when EPA promulgated the MATS rule and removed the "allowance system" definition at 40 C.F.R. § 60.21(k).[33] While EPA purported to also be "revising" 40 C.F.R. § 60.21(f) and 40 C.F.R. § 60.24(b)(1) in the MATS rule, it did not remove the reference to "allowance systems" notwithstanding that the term's definition was removed from the regulations. Accordingly, reliance on an "allowance system" as a valid "emission standard" in a SIP is precarious at best and likely illegal, given the term was added through a rule vacated by the D.C. Circuit.

Commentators continue to promote "credit systems" and other regulatory models premised on the legality of allowance systems as Section 111(d) compliance mechanisms.[34] Absent from these proposals, with purpose as it nullifies the entire regulatory model, is the legislative history outlined above. Assuming for the sake of argument that allowance systems are permissible, there is reason to question the entire "market basis" of allowance system proposals in the first place – these are not markets in a traditional sense, but regulatory constructs without the Pareto outcomes of real markets. Furthermore, market-based systems cannot justify imposition of emission reduction requirements that are not "achievable" through "adequately demonstrated" systems of emission reduction. Any such emission guideline runs facially afoul of 40 C.F.R. § 60.22(5).

A recent NRDC proposal provides a relevant example of the impacts of such an "outside the fence" regulatory framework. NRDC's proposal is a CO_2 emissions cap for each state reflecting the level of total CO_2 emissions from all generation resources that would occur if EPA imposed an emission limit of 1,500 lb CO_2/MWh on all generators. Since that level of emissions is unachievable at an individual coal plant, for example (most existing units emit greater than 2,000 lb/MWh), the only means through which a state could demonstrate compliance with the cap would be to decrease the use of coal plants and increase the use of other resources. As the emissions caps ratchet downwards, *all generation resources with targetable emissions* are at risk, including natural gas. This proposal contradicts the language and history of Section 111(d). A further perversion of this model would be the ultimate squeeze put on states that are natural gas-fired centric in generation. If coal is eliminated, a given state's CO_2 "budget" can only be met by the retirement or carbon capture of natural gas-fired assets.

Third, the Kentucky Plan provides that "[e]ach major GHG emissions sector will contribute proportionately to any overall emissions reduction strategy." This notion is neither developed nor supported; rather, the plan states that CO_2 from the transportation sector will be handled through Corporate Average Fuel Economy Standards and "[p]roportionate GHG emissions from other non-electric generating unit (EGU) emitting sources will be handled under

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31 70 Fed. Reg. 28,606, 28,649 (May 18, 2005).
32 *New Jersey v. EPA*, 517 F.3d 574, 583 (D.C. Cir. 2008).
33 77 Fed. Reg. 9304, 9447 (Feb. 16, 2012).
34 *See, e.g.,* Steven Michel, *A State Model CO2 Emissions Standard for Power Plants,* THE ELECTRICITY JOURNAL (2013).

other EPA-proposed regulations." These latter regulations are not specified. Kentucky uses this unsupported conclusion to justify placing the entire burden of CO_2 emission reduction on EGUs, specifically coal-fired and natural gas-fired generation. Because this means, in practice, that the *entire* CO_2 reduction from a given state must come from only a portion of its CO_2 emitters, namely, power plants, it follows that the cost and regulatory burden of Section 111(d) disproportionately affects the electric sector and rates. As discussed, no fossil fuel is safe under the Kentucky Plan because the reduction targets increase over time – 17% in 2020, 28% in 2025, and 38% in 2030. Once coal-fired generation is taken off-line, the natural gas plants will be targeted next to achieve these reductions.

V. The OKAG Plan

The OKAG Plan avoids the pitfalls outlined above and instead tracks Section 111(d) and its implementing regulations. It keeps the EPA function ministerial in reviewing submitted SIPs and tied to procedure, *i.e.* promulgating emission guidelines, unless and until a State fails to submit an adequate SIP.[35]

Beyond its basis in law, the OKAG Plan recognizes and accounts for the practical reality that air quality impacts differ from State to State, as do costs and opportunities for CO_2 emission reductions. With the OKAG Plan, the resource planning function is *not* usurped by an allocation system or CO_2 budget and instead remains where it belongs – "inside the fence" in the hands of state regulators with specialized expertise and a focus on ratepayer impacts and protection of the public interest. Furthermore, the "inside the fence" model ensures that emissions reductions are limited to the engineering limits of each facility. The OKAG Plan preserves State primacy and does not turn over management of local generation fleets to EPA under the guise of "flexibility."

The OKAG Plan is simple and contemplates the following approach:

- ***State involvement throughout the Section 111(d) process.*** States have a role and input in EPA's promulgation of emission guidelines *before and after* the draft guidelines are published. State officials have detailed knowledge about their respective generation fleets and EPA benefits from taking this into account in the guideline drafting process. This contemplates incorporating the input of *all interested States* – not just States whose leadership shares the same vision of EPA and the Obama Administration.

- ***Unit-by-unit analyses***. Each State will undertake a unit-by-unit analysis to determine achievable and legally enforceable emission standards and compliance schedules that do not require New Source Review. States will not, as in the Kentucky Plan, set an arbitrary emission baseline and haphazard reduction percentages that dictate all subsequent resource planning decisions. The analysis will instead relate directly to the nature and characteristics of the generation fleet.

- ***Promulgation of appropriate "inside the fence" measures.*** Each State will determine appropriate "inside the fence" measures, and ensure that the practical effect of any

[35] *Luminant Generation Co. v. EPA*, 675 F.3d 917, 921 (5th Cir. 2012).

emission guideline is not mandating a best system of emission reduction that completely transforms a generating unit into a different source category.

- ***Consideration of the remaining useful life of existing sources***. Each State may consider the remaining useful life of an existing source and other factors in determining and implementing a performance standard. EPA is required by statute to allow for this consideration. The remaining useful life may, under certain circumstances, justify a regulatory exclusion or application of a less stringent standard of performance.

- ***Consideration of each State's unique economic and environmental attributes.*** This model and its individualized, deferential approach allows States to plan and compensate for varying circumstances and factors that face the generation sector and ratepayers in each State.

- ***Consistency with Section 111(d) and the contemplated regulatory scheme.*** The OKAG Plan, is consistent with Section 111(d) and its implementing regulations. States are left to make, without limitation, the following decisions based on a detailed and exhaustive "inside the fence" analysis:

    - States may prescribe, on a case-by-case basis for particular designated facilities or classes of facilities, less stringent emission standards based upon (1) unreasonable cost of control; (2) physical impossibility; and (3) other factors specific to the facility.[36]
    - States, where appropriate, may defer select decision-making to local jurisdictions provided the emission standards are enforceable by the State.[37]
    - States may extend any individual unit's compliance schedule more than 12 months after SIP submittal so long as the SIP included legally-enforceable increments of progress.[38]
    - States may formulate compliance schedules after plan submittal for individual sources or categories of sources.[39]
    - States may adopt more stringent emission standards or require final compliance at earlier times.[40]

In sum, the State discretion inherent in the Section 111(d) regulatory scheme and State primacy principle demand a unit-by-unit, "inside the fence" analysis to make all of the determinations and exercise the authority conferred by Section 111(d). The OKAG Plan reflects the plain fact that States, not EPA or the Obama Administration, are in the best position to exercise Section 111(d) authority in the best interest of citizens and to balance relevant factors including costs, which will ultimately be paid by local citizens and businesses. If EPA, in recognition of its narrow Section 111(d) authority, were to embrace the OKAG Plan, the Agency may be surprised by the aptitude of the States. The OKAG Plan's "inside the fence" model

[36] 40 C.F.R. § 60.24(f).
[37] 40 C.F.R. §§ 60.24(b)(3), 60.26(e).
[38] 40 C.F.R. § 60.24(e)(1).
[39] 40 C.F.R. § 60.24(e)(2).
[40] 40 C.F.R. § 60.24(g).

would result in States serving as incubators for diverse, *achievable* CO_2 reduction strategies that can be implemented on a unit-by-unit basis in a cost-effective manner without ruinous economic consequences. Further, the OKAG Plan does not take a major policy and political issue, the imperative and timing of reductions in CO_2 emissions, and delegate it to the arcane and obscure workings of a regulatory process into which the public has little input. An anti-carbon agenda should not be forced upon the public through executive or administrative fiat.[41]

VI. Conclusion

EPA's approach to Section 111(d) regulation raises serious concerns. EPA's aggressive course of action with regard to new sources indicates a similarly aggressive approach to existing sources. While EPA is authorized to require States to submit SIPs containing performance standards, EPA may not dictate those performance standards. Nor may EPA attempt to force States to adopt performance standards that are not based on adequately demonstrated technology or that mandate, in the guise of "flexible approaches," the retirement or reduced operation of still-viable coal-based EGUs and subsequent curtailment and elimination of natural gas-fired generation as well.

These concerns are serious as EPA overreach under Section 111(d) may harm the developing economic recovery. Moreover, the federalist system of government, as set forth in the CAA, requires that EPA recognize the rights and prerogatives of States. The OKAG Plan, led by States "inside the fence" rather than EPA in the form of an artificially created CO_2 budget, recognizes those State rights.. It does not rely on a dubious allowance system or pin its legitimacy and achievability on EPA's disputed, even by its own SAB, determination that CCS is adequately demonstrated as achievable at this time. The CCS determination is technically and legally specious.

The fundamental principle underlying the OKAG Plan does not implicate complicated CO_2 trading systems – it simply complies with Section 111(d) and gives States the authority and discretion they are entitled to under the CAA. States serve in the primary role under the proposed framework and devise and control the destiny of their own generating systems, as well as the associated impacts on ratepayers and citizens.

[41] The emissions reductions achievable through an "inside the fence" approach, even if *numerically* less than an "outside the fence" approach, are sound from a policy perspective. Due to other EPA regulations, there are numerous EGUs, primarily older and less efficient, that are already either retired or committed to be retired. If further emission reductions are mandated, then emission reductions would be achieved from newer and more efficient units. These latter forced retirements are inequitable and compromise system reliability.