STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY (I&M), AN INDIANA CORPORATION, FOR APPROVAL OF A CLEAN ENERGY PROJECT AND QUALIFIED POLLUTION CONTROL PROPERTY AND FOR ISSUANCE OF CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR USE OF CLEAN COAL TECHNOLOGY; FOR ONGOING REVIEW; FOR APPROVAL OF ACCOUNTING AND RATEMAKING, INCLUDING THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF SUCH PROJECT THROUGH I&M'S CLEAN COAL TECHNOLOGY RIDER; FOR APPROVAL OF DEPRECIATION PROPOSAL FOR SUCH PROJECT; AND FOR AUTHORITY TO DEFER COSTS INCURRED DURING CONSTRUCTION AND OPERATION, INCLUDING CARRYING COSTS, DEPRECIATION, TAXES, OPERATION AND MAINTENANCE AND ALLOCATED COSTS, UNTIL SUCH COSTS ARE REFLECTED IN THE CLEAN COAL TECHNOLOGY RIDER OR OTHERWISE REFLECTED IN I&M'S BASIC RATES AND CHARGES.	**) CAUSE NO. 44871**

<u>SUBMISSION OF REDACTED DIRECT TESTIMONY & PUBLIC EXHIBITS</u>

Citizens Action Coalition of Indiana, Sierra Club, and Valley Watch (collectively, "Joint Intervenors"), by counsel, respectfully submit the following redacted prefiled testimony of Jeremy Fisher, PhD, and public exhibits in the above captioned Cause to the Indiana Utility Regulatory Commission ("Commission"). I&M is currently evaluating the unredacted testimony of Jeremy Fisher, PhD, and the confidential exhibits to ensure that they are protected as confidential on a preliminary basis under the docket entry issued on December 5, 2016. Joint Intervenors will file the unredacted testimony and confidential exhibits as soon as that is resolved.

Respectfully submitted,

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The undersigned hereby certifies that the foregoing was served by electronic mail or U.S. Mail, first class postage prepaid, this 3rd day of February, 2017, to the following:

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STATE OF INDIANA

Indiana Utility Regulatory Commission

VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY (I&M), AN INDIANA CORPORATION, FOR APPROVAL OF A CLEAN ENERGY PROJECT AND. QUALIFIED POLLUTION CONTROL PROPERTY AND FOR ISSUANCE OF CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR USE OF CLEAN COAL TECHNOLOGY; FOR ONGOING REVIEW; FOR APPROVAL OF ACCOUNTING AND RATEMAKING, INCLUDING THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF SUCH PROJECT THROUGH I&M'S CLEAN COAL TECHNOLOGY RIDER; FOR APPROVAL OF DEPRECIATION PROPOSAL FOR SUCH PROJECT; AND FOR AUTHORITY TO DEFER COSTS INCURRED DURING CONSTRUCTION AND OPERATION, INCLUDING CARRYING COSTS, DEPRECIATION, TAXES, OPERATION AND MAINTENANCE AND ALLOCATED COSTS, UNTIL SUCH COSTS ARE REFLECTED IN THE CLEAN COAL TECHNOLOGY RIDER OR OTHERWISE REFLECTED IN I&M'S BASIC RATES AND CHARGES.	CAUSE NO. 44871

Direct Testimony of
Jeremy I. Fisher, PhD

On Behalf of
Citizens Action Coalition of Indiana,
Sierra Club, and Valley Watch

PUBLIC VERSION

February 3, 2017

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A My name is Jeremy I. 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 and policies for electricity sector issues, including fossil generation, efficiency, renewable energy, ratemaking and rate design, restructuring and market power issues, and environmental regulations.

Q Please summarize your work experience and educational background.

A I've worked in electricity system energy planning for a decade, evaluating and helping to shape resource plans, performing planning on behalf of states and municipalities, helping regulators navigate environmental rules, and assisting states craft or revise resource planning rules. I lead the resource-planning group at Synapse, which engages in the assessment of planning processes across a wide cohort of states and regions.

I have provided consulting services for a wide variety of public sector and public interest clients, including the U.S. Environmental Protection Agency ("EPA"), the National Association of Regulatory Utility Commissioners ("NARUC"), the National Association of State Utility Consumer Advocates ("NASUCA"), National Rural Electric Cooperative Association ("NRECA"), the energy offices and public utility commissions of Alaska, Arkansas, Michigan, and Utah, the Commonwealth of Puerto Rico, Tennessee Valley Authority Office of Inspector General ("TVA OIG"), the California Division of Ratepayer Advocates ("CADRA"), the California Energy Commission ("CEC"), the Regulatory Assistance Project ("RAP"), the Western Grid Group, the Union of Concerned

Scientists ("UCS"), Sierra Club, Earthjustice, Natural Resources Defense Council ("NRDC"), and other organizations.

I have provided testimony in electricity planning and general rate case dockets in California, Indiana, Kansas, Kentucky, Louisiana, Nevada, New Mexico, Oklahoma, Oregon, Puerto Rico, Utah, Washington, Wisconsin, and Wyoming.

I hold a doctorate in Geological Sciences from Brown University, and I received my bachelor degrees from University of Maryland in Geology and Geography.

My full curriculum vitae is included as Attachment JIF-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Citizen's Action Coalition of Indiana, Sierra Club and Valley Watch ("Joint Intervenors").

Q Have you testified in front of the Indiana Utility Regulatory Commission previously?

A Yes. I testified in various recent applications for Certificate of Public Convenience and Necessity ("CPCN") before this Commission, including Causes 44242, 44339, and 44446. I was also invited to be a speaker at the Indiana Utility Regulatory Commission's ("IURC" or "Commission") Emerging Issues in IRP conference in October 2013.

Q Have you engaged in other states on long-term resource planning issues?

A Yes. I have been involved in numerous long-term resource planning dockets, including integrated resource plans ("IRP"), CPCN, and prudence reviews in rate case dockets. I have provided training to federal regulators on resource planning practice and issues. I recently led an intensive statewide planning process on behalf of the Michigan Public Service Commission ("MPSC") and continue to work on behalf of the recently appointed Puerto Rico Energy Commission ("CEPR") in an intensive review of the Commonwealth's first public resource plan.

Q What is the purpose of your testimony?

A In this case, Indiana Michigan Company ("I&M" or "Company") seeks a CPCN to install Selective Catalytic Reduction ("SCR") at Rockport Power Plant Unit 2 ("Rockport 2") near the town of Rockport, Indiana. My testimony assesses the analysis conducted by American Electric Power Generating Services ("AEPGS") on behalf of I&M in support of this application, and examines if the installation of controls at this time is in the interest of I&M's ratepayers.[1] In addition, I examine the basic specifications for the SCR planned for installation by I&M, in light of the Company's regulatory requirements, and assess if the Company's proposal is consistent with its requirements.

Q Please describe the basis of the project considered by I&M in this proceeding.

A In 2007, I&M signed a Consent Decree with the United States Environmental Protection Agency ("EPA") and other parties, including Sierra Club, to settle various alleged violations of the Clean Air Act by the Company, its parent, American Electric Power ("AEP"), and other subsidiaries of AEP. The Consent Decree requires that the Company "install and Continuously Operate SCR" at Rockport 2 no later than December 31, 2019.[2]

Q What decisions do the Company and this Commission face in choosing whether to install the SCR?

A In many respects, this application and the decisions faced by I&M in this proceeding are unique. For most other vertically integrated power plant owners, the decision to invest in an environmental retrofit—or any other substantial capital investment—is relatively straightforward: spend the capital in anticipation of continuing to operate the power plant over a relatively long period, or cease

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[1] Because of the relationship between I&M and AEPGS (both affiliates of the parent company American Electric Power), and the fact that AEPGS presents the analysis in this testimony on behalf of I&M, I will refer to both I&M and AEPGS as "Company."

[2] *See* Attachment JCH-1 to the Direct Testimony of John C. Hendricks, at 24-25.

operations and seek a least cost replacement alternative. In I&M's case, the decision is complicated because I&M does not own Rockport 2.

Rockport 2 is owned by a financial conglomerate of non-utility investors with whom I&M and an affiliate, AEG, have signed a long-term lease. This lease, which expires in 2022, requires that I&M maintain Rockport in operable condition, which in this case would require the installation of the SCR.

It is not clear that I&M would want to renew the lease even if such an opportunity presented itself in 2022. So instead of a binary decision between installing the SCR or ceasing operations, I&M faces a triple, or trinary, decision: install the SCR with the assumption that the lease will be renewed, install the SCR with the assumption that the lease will not be renewed, or not install the SCR and withdraw from the lease.

The Company has modeled these three avenues, terming them Option 1A (install SCR and maintain Rockport 2 indefinitely), Option 1B (install the SCR but withdraw from the lease in 2022), and Option 2 (avoid the SCR and withdraw from the contract in 2019). In addition, the Company added one additional Option 2A in which I&M avoids the SCR and withdraws from the contract, but does not replace Rockport 2 for three years after the retirement.

The Company's avenues here are not enviable. If maintaining Rockport indefinitely is not an economically efficient avenue, the Company faces the prospect of either stranding the cost of a brand-new SCR in 2022 or incurring a termination penalty to withdraw from the Rockport 2 lease in 2019.

Q What is the Company's conclusion with respect to the installation of the SCR at Rockport 2?

A The Company believes its analysis indicates that the installation of the SCR at Rockport 2 in 2019 is prudent, if only for the option value. As stated in I&M's 2015 IRP, upon which this application is based, "the primary driver of this result is that the lease termination payment that I&M would be assessed if Rockport

Unit 2 was retired in 2019 significantly exceeds the estimated cost of the SCR. In addition, retiring Rockport Unit 2 would result in the loss of three years of market revenues which offset I&M customer load costs."[3]

The Company contends that, amongst the modeled options, Option 1A (maintaining Rockport indefinitely) is the least cost option, followed by Option 1B ($84 million more expensive) and Option 2 ($322 million more expensive).[4] Mr. Scott Weaver, testifying on behalf of the Company, states that the "relative 'Option #1A versus Option #1B' economics would indicate that it is currently 'too close to call'"; he suggests that "the proposed Rockport Unit 2 SCR Project solution may also be viewed as preserving an option for I&M and its customers to consider the prospect of continuing to operate Rockport Unit 2 over the long-term."[5] The Company rejects the idea of exiting the plant agreement and not immediately replacing the capacity (Option 2A) as the most expensive option considered, at $346 million more expensive than Option 1A.[6]

Ultimately, the Company contends that the SCR at Rockport 2 offers "significant optionality,"[7] and "afford[s] the ability to capitalize on significant relative value… even for a brief, 3-year period that would lead up to a potential Return to Lessor disposition."[8]

Q What is your opinion with respect to the Company's decision underlying this application?

A I do not substantially disagree with structure of the Company's decision *framework*, which seeks to understand the balance between short-term optionality and long-term risk. However, such a decision ought to rely on a robust analysis, reasonable inputs, and a reasonable interpretation of the analysis results. I believe

[3] I&M 2015 Integrated Resource Plan. Section 5.2.2.3. "Optimization Modeling Results of Rockport 2 Retirement Sensitivity." Attachment JIF-2.
[4] Direct Testimony of Mr. Scott Weaver, page 39 at 20 through 40 at 12.
[5] Direct Testimony of Mr. Scott Weaver, page 41 at 16 through 42 at 1.
[6] Direct Testimony of Mr. Scott Weaver, page 49 at 17 through 50 at 2.
[7] Direct Testimony of Mr. Scott Weaver, page 4 at 20-25.
[8] Direct Testimony of Mr. Scott Weaver, page 47 at 11-14.

that the Company has been disingenuous about its selective interpretation of the analysis results, relied on outdated inputs, made several key analysis errors, and artificially weakened the robustness of the analysis.

Specifically:

The Company has been **disingenuous about its interpretation of the analysis** results by inappropriately relying on flawed results that emphasize outcomes which might occur more than thirty years in the future (the “end-effects period”). In contrast, the results from the core analysis period run counter the Company’s findings. The construction of the end-effects period analysis as employed by the Company relies on faulty assumptions with respect to the long-term costs of running Rockport, which the Commission should dismiss outright. The Company’s selective interpretation of results biases the Company towards the assumption that Rockport 2 has a long-term value to I&M ratepayers.

The Company **relied on outdated inputs** by using fuel and capacity price forecasts that are now over a year and a half old and are substantially different than current Company estimates. Prudent utility practice requires that utilities use the best and most current data at the time of a resource decision. The use of outdated data for both fuel and capacity market prices substantially favors the Company’s analysis towards the continued use of Rockport 2.

The Company **made several key analysis errors** in the consideration of ongoing capital costs at Rockport 2 prior to the years when the unit is assumed to retire, biasing the Company’s analysis in favor of building the SCR, even if the unit retires in 2022.

The Company’s analysis subjects I&M to **substantial litigation risk** by seeking to build a sub-standard SCR and planning for substantially reduced ongoing capital at Rockport 2 prior to the expiration of the Company’s lease.

Finally, the Company **artificially weakened the robustness of the analysis** by overpricing reasonable alternative energy options.

2. FINDINGS AND RECOMMENDATIONS

Q What are your findings in your assessment of the Rockport 2 CPCN?

A I find that Rockport 2 is not a reasonable long-term resource and under current projections is likely to become a sizable liability to I&M ratepayers. I find that the Company's analysis is unacceptably outdated and does not reflect the state of the market today according to either public data sources or the Company's own analysis. When the Company's analysis is updated, Option 1A (installing SCR and renewing the lease) is not cost-effective under reasonable assumptions.

I describe and execute four sequential adjustments to the Company's analysis: the removal of an erroneous end-effects calculation, updating a year-and-a-half old fuel price forecast relied upon by the Company, correcting Company mistakes in the calculation of ongoing capital costs, and recommending a capacity price forecast more consistent with known market behavior.

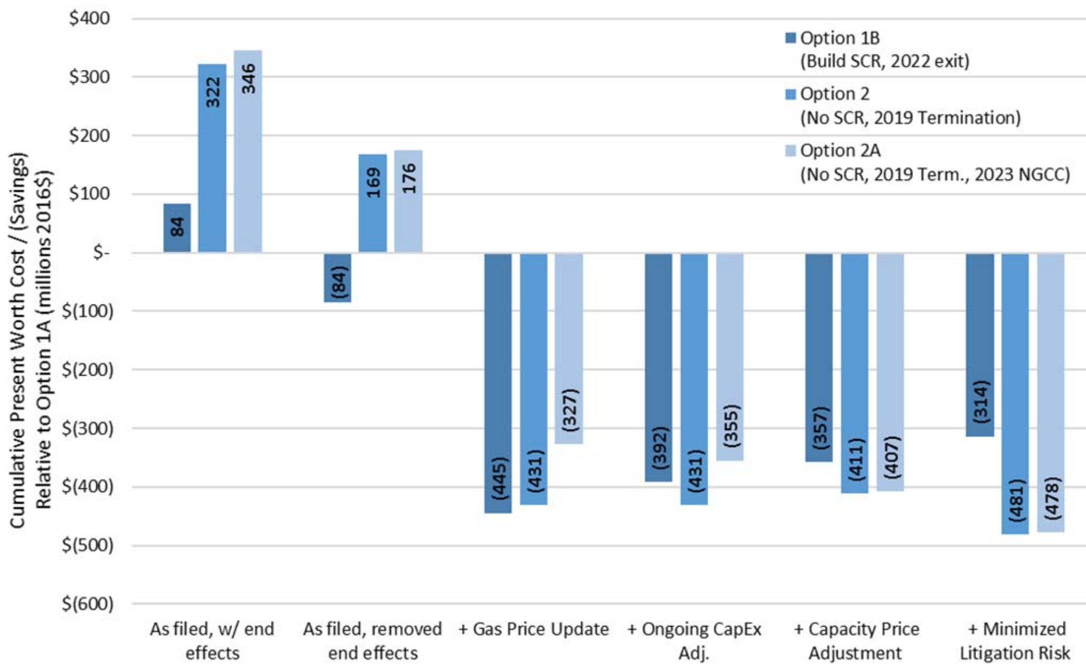
These adjustments substantially impact the decision to proceed with the SCR against other options examined by the Company. Table 1, below, shows the changing cumulative present worth ("CPW") of the Options examined by the Company with corrections and adjustments.

Table 1. Cumulative present worth (CPW) of alternative scenarios across adjustments (million 2016$), incremental adjustments by column.

	As filed, w/ end-effects	As filed, removed end-effects	+Gas Price Update	+Ongoing CapEx Adj.	+Capacity Price Adjustment	+Minimized Litigation Risk
Option 1A (SCR, continued use)	$16,153	$12,579	$13,607	$13,607	$13,675	$13,745
Option 1B (SCR, 2022 exit)	$16,237	$12,495	$13,163	$13,215	$13,318	$13,432
Option 2 (No SCR, 2019 termination)	$16,475	$12,748	$13,176	$13,176	$13,264	$13,264
Option 2A (No SCR, 2019 termination, 2023 replace)	$16,499	$12,755	$13,280	$13,252	$13,268	$13,268

The differences are more readily illustrated relative to Option 1A, the decision to retrofit with the SCR and maintain Rockport 2 through the indefinite future. Figure 1, below, shows the CPW difference relative to Option 1 through the adjustments. Bars above zero indicate that under the adjustment, the alternative option is more expensive than Option 1A, while bars below zero indicate savings relative to Option 1A.

Figure 1. Cumulative present worth (CPW) of alternative scenarios across adjustments, relative to Option 1A (long-term use of Rockport 2) (millions 2016$)



It becomes immediately apparent through this series of adjustments that the option to install SCR and maintain Rockport past 2022 is neither viable nor reasonable under current market conditions. Even the Company's own analysis—not updated with contemporary gas prices but simply removing the erroneous end-effects calculation (described later)—indicates that Rockport 2 has a negative value if maintained past 2022.

Updating the Company's analysis to account for updated fuel price forecasts—both those in the public record, and as used by the Company in other jurisdictions—and excluding the erroneous end-effects calculation of the Company, I find that the options to install an SCR and allow the lease to expire (Option 1B) or withdraw from the lease and avoid the SCR (Option 2) are roughly equal in value ($445 or $431 million less expensive than Option 1A, as seen in "Gas Price Update" column in Figure 1).

However, I have reason to believe that the Company incorrectly modeled Option 1B, which biased the results with regard to the ongoing capital costs incurred at Rockport 2 as the unit nears retirement. Correcting modeling errors in Option 1B and 2A, I find a marginal benefit ($39 million) in the option to terminate the lease at Rockport 2 in 2019 as opposed to retrofitting with the SCR.

I believe that the capacity price forecast put forth by the Company is not supported by actual market prices and expectations, or even the Company's most recent updated price estimates. Conservatively adjusting this value, both options to terminate the lease with the Rockport 2 owners in 2019 have a benefit of $55 million—a total adjustment of over $700 million relative to the Company's contention that maintaining Rockport for the indefinite future is beneficial. This tells quite a different story than that told by the Company.

I have substantial concerns that the Company's primary options (1A and 1B) pose additional substantial litigation risk from the enforcement agencies, signatories of the Consent Decree, and the Lessors of Rockport 2. Options 1A and 1B propose a sub-standard SCR, and in doing so may breach both the Consent Decree and I&M's lease on Rockport 2, as I will discuss later in this testimony. Option 1B, the fallback proposed by the Company, exposes I&M to further litigation risk by proposing to reduce critical ongoing capital expenditures. In doing so, it may prevent the Company from meeting the strict terms of the lease if the plant is not in fully operable and maintained condition by its return in 2022. Taking these concerns into account, the option value of the SCR is reduced considerably while the certainty of the admittedly onerous 2019 termination fee is attractive.

Finally, the extent to which lower-cost, lower emissions options, such as renewable energy, were excluded from serious consideration renders this an incomplete and unreasonably constrained analysis.

Q How do you recommend this Commission proceed?

A My primary recommendation is that the Commission deny the CPCN on the basis that neither of the options examined by the Company for the installation of SCR are least cost or least risk for ratepayers. Further, the Commission should require that I&M expediently file a plan for the replacement of the capacity and energy requirements otherwise met through Rockport 2.

The Company's filing is outdated, and its filing timeline relative to the installation schedule for the SCR leaves this Commission with far less leeway than appropriate. As such, if it does not reject the CPCN, the Commission should require a number of simultaneous conditions to protect ratepayers and encourage prudent planning: (a) that the Company update this analysis and present it to the Commission for review by April 2017; (b) that intervenors be afforded an opportunity to review and comment on this analysis by October 2017; (c) that the Commission retain the opportunity to hold back future funds if it is determined that the Company has proceeded against the best interests of ratepayers; (d) that the Company be required to file a request for approval to exit or renew the lease at Rockport at least one year prior to informing the lessor of such decision; (e) that I&M shareolders hold the responsibility for all litigation fees and penalties resulting from any non-compliance with the Consent Decree; (f) that I&M shareholders hold the responsibility for all litigation fees and penalties from contract breach as a result of the Company's forward-looking plan from today; and (g) that I&M be restricted to recovery of a fixed percentage deadband around the $137.1 million capital estimate; and (h) that I&M be required to aggressively pursue all cost-effective energy efficiency and renewable energy options in advance of the lease termination date of 2022.

3. Analysis Miscalculates and Overemphasizes Costs After 2045

Q What are end-effects?

A An end-effects calculation is used to analyze differences between alternatives after the planning period, which extends from 2016 to 2045. Different resource options have different operating lives and characteristics. End-effects are an imperfect way of estimating those long-lived impacts without explicitly modeling a far longer analysis period. This calculation is most useful when a cash flow analysis uses actual capital depreciation schedules (i.e., declining balance) and truncates these schedules artificially at the end of an analysis period.

Q Is the calculation of end-effects strictly necessary in this case?

A No. AEP has long assessed end-effects, a practice common when the Company relied on the Strategist® model, a model which has now been replaced with Plexos® LT. In the current model structure, capital investments are levelized with a capital recovery carrying charge, which accounts for the different operating lives of different resources. Effectively, using a levelized version of a capital investment renders the model agnostic to resource life, and thus substantially diminishes the need for an end-effects calculation. End-effects can be important in cases where a particular cost category is expected to jump substantially in an out year—such as carbon prices. This is not the case in this analysis.

In addition, the Company has introduced an error into the analysis through a mistake in the calculation of end-effects.

Q How should one consider the import of end-effects in a long-run analysis?

A In general, the end-effects period should serve as a double check on the overall analysis results during the study period. It is rare, and a red flag, that the end-effects calculation runs counter to the study period results. Such an outcome indicates either an analytical error or a substantial change in the last years of the study period that drive results.

In the case of this analysis, the study period covers 30 years, from 2016 to 2045. Our ability to forecast any variable decently at such a far-flung period is fraught, and thus one should generally be skeptical about strong trends that emerge specifically near or at the end-effects period.

AEP would appear to agree, but is selective about when it chooses to rely on the end-effects calculation. In 2011, in a Kentucky docket, AEP assessed a retrofit at the Big Sandy power plant and conducted an analysis through 2040. Trying to understand internal inconsistencies, Sierra Club (an intervenor in that docket) asked if the Company had included an end-effects period in the Strategist modeling. Mr. Weaver, responding on behalf of the Company, wrote:

> There was no end-effects period modeled in Strategist. However, the study was conducted over the time period of 2011 to 2040. **This period is sufficiently long enough to cover the life of the retrofits and the majority of the life of the gas replacement alternatives**. In addition, due to the significant present worth discounting of costs after 2040, any relative cost impacts after that point would be very small.[9]

There should generally be very few circumstances in which the discounted cost of impacts, which occur more than thirty years in the future, should substantially change the outcome of a resource planning assessment.

Q What is the impact of the Company's end-effects calculations on its conclusions in this case?

A In this case, the Company's end-effects calculations are decisive. In the absence of end-effects, the Company estimates that its Option 1B results in $84 million in net present value savings relative to Option 1A. However, when end-effects are

[9] Kentucky PSC Docket 2011-00401. KPCo (AEP) Response to Sierra Club Data Request 39. January 13, 2012. Attachment JIF-3. Also available online at http://psc ky.gov/PSCSCF/2011%20cases/2011-00401/20120127_KY%20Powers%20Response%20to%20Sierra%20Clubs%20Initial%20Set%20of%20DR.pdf.

included, the Company estimates that Option 1B is $84 million *more costly* than Option 1A.[10] This swing of $168 million leads the Company to conclude that, under its base assumptions, Option 1A is its most cost-effective alternative.

Q How does the Company justify its decision to incorporate end-effects in its analysis?

A In contrast to Mr. Weaver's view held in 2011, in this case the Company claims that it is "necessary to examine end-effects to fully capture any recovery of capital cost expenditures made prior to the last year of the modeling period."[11] The primary results presented by Mr. Weaver in this case rely on the end-effects calculation.

Q How has the Company calculated end-effects in its scenario analyses?

A As described in response to discovery, the Company calculated the end-effects associated with each scenario by multiplying the last year of the modeling period's "grand total net utility costs," less any "adjustment for uniquely-determined fixed cost end-effects," by a perpetuity factor.[12] The "uniquely-determined" end-effects—those effects associated with Rockport major capital and on-going capital costs—were calculated separately, and added back into the total-end-effects calculation.[13]

The Company estimated Rockport major capital cost end-effects by simply adding in the present value of Rockport environmental capital costs that hadn't been accounted for by the end of the modeling period.[14] Similarly, the Company calculated end-effects associated with on-going capital costs based on the modeling-period on-going capital costs that remain un-amortized at the end of the modeling period.

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[10] Attachment SCW-4A to Direct Testimony of Scott C. Weaver.
[11] I&M Response to JI Data Request 3-06(c). Attachment JIF-4.
[12] I&M Response to JI Data Request 3-06(b). Attachment JIF-4.
[13] I&M Response to JI Data Request 3-07. Attachment JIF-5.
[14] *See*, e.g., workpaper "4- IM_WP_Ex SCW-4A_Option 1A_BASE Pricing_(CPW Modeling Results Detail)_102116.xlsx," tab "Fixed Costs," cells S41:S42.

Q What is wrong with the Company's end-effects calculation?

A End-effects calculations that use levelized capital costs generally assume that all costs incurred at the end of the analysis period are effectively frozen in perpetuity. This is, in effect, a way of analytically stating what would occur if resources were simply replaced in-kind at the end of their useful lives in perpetuity.

In this case, the Company has selectively chosen which costs to include, or exclude, from the end-effects period, biasing the analysis. For example, by simply taking the present value of the environmental costs at Rockport that hadn't been amortized by 2045, the Company effectively assumes that Rockport continues to exist in perpetuity but never again spends dollars on the repair or replacement of the SCRs or flue gas desulfurization FGD equipment. In fact, the analysis assumes that these investments reach the end of their service life and are not replaced, but Rockport continues to provide power.

With respect to ongoing-capital costs, the error in the end-effects period is even more problematic. The end-effects calculation used by the Company simply assumes that I&M ceases investing *any* capital in Rockport after 2045.[15] The Company simply accounts for capital spent up through 2045 and no further. In effect, the Company assumes that in the end-effects period, the Company is entitled to all of the energy and capacity provided by Rockport and pays for no maintenance, upgrades, retrofits, or replacement capacity. This is an absurd assumption; the Company cannot reasonably maintain that, *for all eternity*, it will neither have to continue to invest in capital improvements and environmental controls at Rockport nor retire and replace Rockport's capacity. Yet this is precisely what the Company assumes through its misleading treatment of Rockport major-capital and on-going-capital end-effects. This treatment of end-effects up-ends the purpose of such an assessment and imparts a substantial bias.

[15] Refer to workpaper "I&M_(CONFIDENTIAL)WP_Ex SCW-3_(Rockport Unit FOM and OGC Fcst Detail)_102116," tab "RP 1&2 No Retirement OGC" cell AI4.

For this reason, I recommend that the Commission disregard the end-effects components of the Company's analysis.

Q What is the impact of disregarding the end-effects portion of the Company's analysis?

A The end-effects error imposed by the Company (i.e., assuming no additional capital costs at Rockport after 2045) is highly biased in favor of Option 1A. Therefore, removing end-effects decreases the overall CPW of the scenarios, [16] but increases the cost of Option 1A by about $150-$170 million relative to the other options examined by the Company. This correction inverts the position of Option 1A and 1B, with Option 1B slightly more cost effective than 1A by $84 million, and it reduces relative cost of a 2019 (Option 2) termination to approximately $170 million more than Option 1A—a drop of nearly 50 percent.

Table 2. Relative cost / (savings) of Options 1B, 2, and 2A relative to Option 1A, total CPW (million 2016$), end effects adjustment

	Option 1B (Build SCR, 2022 exit)	**Option 2** (No SCR, 2019 Termination)	**Option 2A** (No SCR, 2019 Term., 2023 NGCC)
As filed, with end-effects	$84	$322	$346
No end-effects	($84)	$169	$176

4. ANALYSIS USES OUTDATED FUEL PRICE FORECASTS

Q When were the fuel prices for the Company's analysis generated?

A The fuel prices for this application were generated in June 2015, a full year and a half prior to the application date.[17] With the rapid expansion of natural gas drilling, gas price forwards have generally been falling over the last seven years.

[16] Attachment SCW-4A to Direct Testimony of Scott C. Weaver.

[17] Direct Testimony of Mr. Scott Weaver, page 25 at 12 to 17. "Attachment SCW-2 offers the long-term commodity pricing forecast established by the AEP Fundamental Analysis group in that same June/July 2015 timeframe."

However, in 2014 and 2015, the US Energy Information Administration ("EIA") was forecasting a slightly higher forecast than in 2013. By mid-2016, long-term forward markets were revised substantially downward. Therefore, 2015 represents a local high for the forward market prices of gas.

Q What is the Company's justification for the use of an outdated commodity price forecast in this assessment?

A The Company states that "the long-term commodity price forecasts used in this Rockport Unit 2 SCR project analysis… [are] consistent with the pricing forecasts used in I&M's recent (November 2015) IRP submittal."[18] It does not provide a justification for relying on these outdated commodity price forecasts, aside from their consistency with the 2015 IRP. The Company does not state so, but it may rely on the operative IRP draft proposed rule which states that "when a utility takes a resource action, it shall be consistent with the most recent IRP… including its (1) inputs; [and] (2) data and assumptions… unless any differences between the most recent IRP and the resource action are fully explained and justified with supporting evidence."[19]

This clause of the draft proposed rule is in place to prevent utilities from doing a "bait and switch" (providing a baseless IRP) and is meant to ensure that a utility takes the IRP process seriously—as near to binding as feasible without being a preapproval docket. Interpreting the draft proposed rule to mean that a utility is neither able to, nor expected to, consult the most up-to-date information prior to making a resource decision on ratepayers would not be reasonable. The IRP does not relieve the utility of its obligation of prudent utility practice.

[18] Direct Testimony of Mr. Scott Weaver, page 37 at 17 to page 38 at 2. Statement issued as question, answered affirmatively.
[19] 2016-0705 RM 15-06 Draft Proposed Rule redline. 170 IAC 4-7-2.5 Effects of Integrated Resource Plans in Docketed Proceedings. Section 2.5(b)

Q **Is it reasonable to rely on outdated forecasts for a resource decision such as this one, irrespective of the consistency with a prior filing?**

A No. When making a decision of the magnitude contemplated by this CPCN application, it is essential to use the most up-to-date information available. It makes no sense for the Company to use assumptions that no longer reflect today's conditions simply for the sake of consistency. Using outdated information in the name of consistency would be an academic exercise that does not follow prudent utility practice. What matters to ratepayers, and should matter to the Company as well, is if the decision is in the best interest of customers under current market conditions.

The Company bears an obligation, both before this Commission and even outside of this or any other litigated proceeding, to ensure that its decisions are prudent at the time they are executed. This CPCN and pre-approval functions as a prudence review that is contemporaneous with the decision, rather than *post-hoc*. In this prudence review, the Company must show that it went through a reasonable decision-making process to arrive at a course of action **given the facts as they were or should have been known at the time**.

The Company's application should have been up-to-date with the most recent price forecasts available to the Company, and by that measure the Company failed to submit a reasonable application.

Q **Does the Company have in its possession a more up to date fundamentals assumption?**

A Yes. Joint Intervenors asked the Company to "provide any AEP Fundamentals Analysis and/or Long-Term Commodity Price Forecasts that are more recent than the mid-2015 forecast provided here."[20] In response, the Company provided an undated Fundamentals forecast with substantially different data than used in the

[20] I&M Response to JI Data Request 4.6(c). Attachment JIF-06.

CPCN.[21] Later, I'll demonstrate that these updated fundamental forecasts were used in a recent Kentucky Power IRP.

Q Should this Commission expect the Company to use the most up-to-date forecast in assessing the CPCN?

A Yes. As a case in point, in September 2016 the Washington Utilities and Transport Commission ("WUTC") determined that PacifiCorp "placed ratepayers at risk of larger-than-appropriate expenses in abandoning its responsibility to pursue, and document its pursuit of, the least-cost option" when evaluating emissions retrofits at large fossil plant.[22] The Commission determined that the utility had failed to update key commodity price estimates prior to its decision to proceed in executing on the retrofits, and that such updates could have substantially changed the outcome of the Company's decision. The Commission determined that in failing to update their own internal analysis "[the Company's] decision to continue the SCR installation project was not sufficiently demonstrated to be prudent in all respects,"[23] and made a disallowance.

It is critically important that decisions be evaluated on the best possible sources of information, particularly as markets shift. Simply maintaining that a decision relies on outdated information for "consistency" in the face of new facts is not reasonable utility practice.

Q How does the Company characterize its commodity price forecasts?

A The Company's analysis reviews three basic fuel price outlooks, which the Company terms the "BASE Forecast," the "Higher Band," and a "Lower Band." The Higher and Lower Band forecasts are exactly 14 percent higher and lower, respectively, than the BASE Forecast on a levelized basis.

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21 I&M's Attachment to JI Data Request Response 4-6 (JI_DR_Set_4_Q6c.xlsx). Attachment JIF-7.
22 Washington Utilities and Transportation Commission. Docket UE-152253. Order 12. Page 93. Attachment JIF-8.
23 *Ibid*.

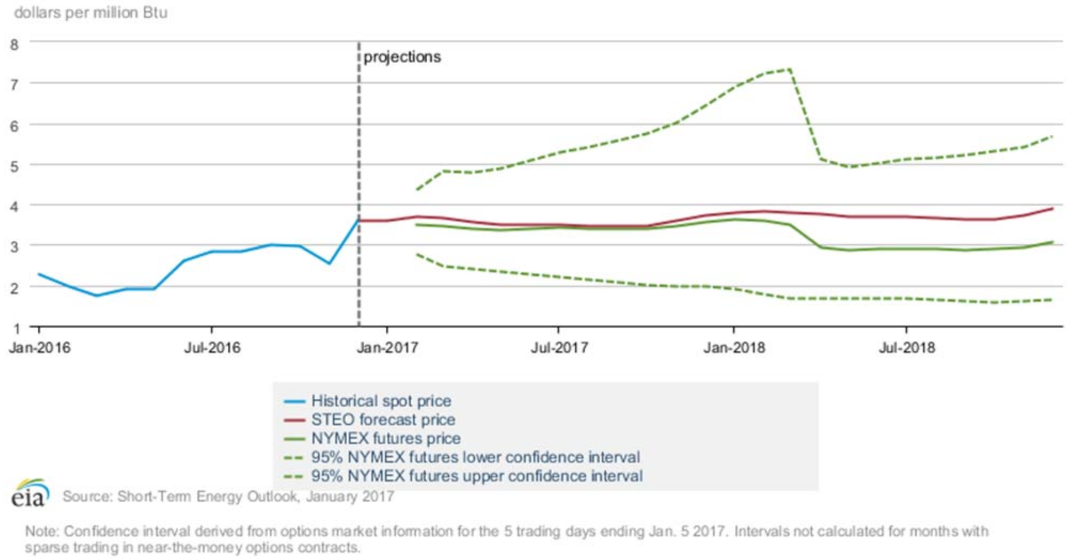
Q What is your basis for indicating that the fuel prices used in the analysis are outdated?

A I have three indicators that the natural gas price forecast used by I&M in this case is outdated and too high.

The first indicator is simply the first year natural gas price used in the analysis. The BASE price forecast indicates natural gas prices at Henry Hub at \$4.34/MMBtu in 2016;[24] in fact, in 2016, prices at Henry Hub averaged \$2.51/MMBtu,[25] or 42 percent lower. While prices are expected to increase moderately, they are not expected to recover to the extent anticipated by I&M in this application. While I&M predicted gas prices nearing \$5.50/MMBtu in 2018 in the BASE case, the NYMEX commodities market does not predict prices to clear \$4.00/MMBtu at any time in the span of traded futures (by mid-2019).[26] Figure 2, below, shows both NYMEX and the EIA's forecasts for gas prices through the end of 2018. By 2019, I&M's gas price forecast is anywhere from 37 to 83 percent higher than EIA or NYMEX, respectively.

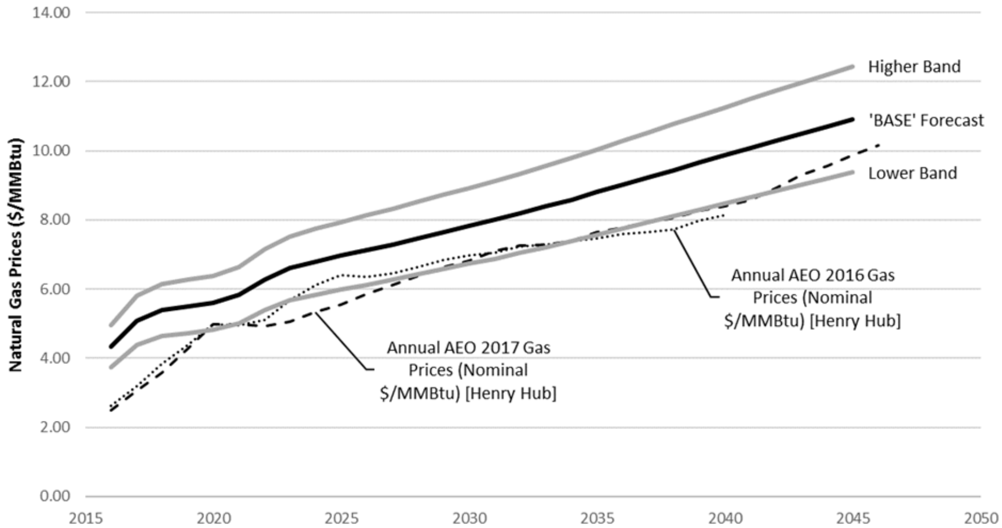
[24] See I&M workpaper 1- IM_WP_Ex SCW-2_(LT Fund Commodity Price Fcsts)_102116.xlsx, tab "Ex_SCW-2 (LT Pricing)", cell E15.
[25] US EIA, Short Term Energy Outlook. Short-Term Energy Outlook – January 2017. Table 2. Energy Prices. Available at. http://www.eia.gov/outlooks/steo/tables/pdf/2tab.pdf
[26] NYMEX market data accessed January 30, 2017. Futures thin substantially after early 2019.

Figure 2. Henry Hub natural gas price from EIA Short Term Energy Outlook and NYMEX futures (nominal)



The second indicator is derived from the long-term forecast in both the U.S. Energy Information Administration (EIA) 2016 Annual Energy Outlook (AEO), released September 15, 2016, and the AEO 2017, released January 5, 2017. The forecast gas prices in this widely used and vetted forecast source are substantially lower than the prices in the BASE forecast relied upon by the Company in this analysis. In fact, by 2020, both the AEO 2016 and 2017 forecasts are almost in line, if not lower than, I&M's "Lower Band" forecast (see Figure 3 below).

Figure 3. Henry Hub natural gas price gas price forecast from I&M Analysis (June 2015), AEO 2016 (September 2016), and AEO 2017 (January 2017)



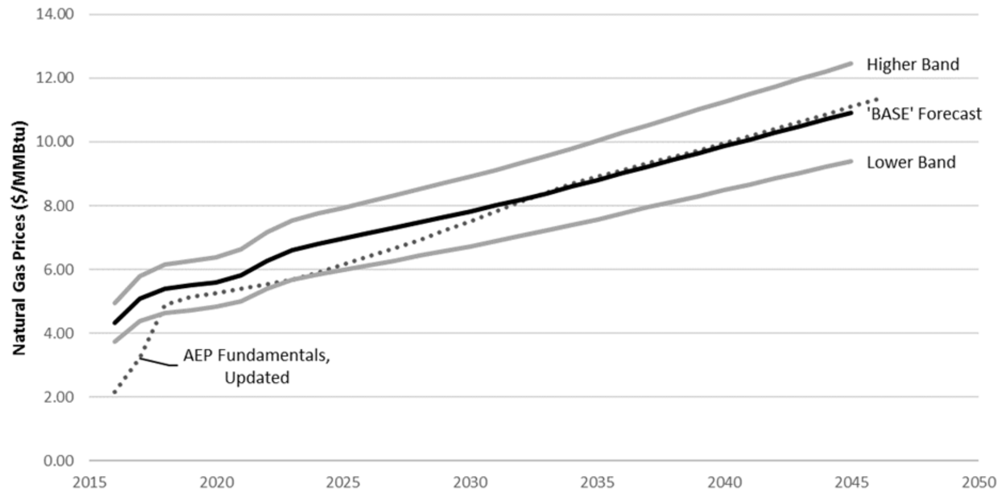
AEO 2016 represents a forecast that would have been available to the Company at the time of filing (October 2016), while the AEO 2017 forecast represents the most up-to-date forecast available to the Commission today and the basis for my assessment of the CPCN.

As I noted previously, the Company provided a more recent commodity price schedule in response to a request from Joint Intervenors.[27] Intervenors asked that the Company "provide any AEP Fundamentals Analysis and/or Long-Term Commodity Price Forecasts that are more recent than the mid-2015 forecast provided here." The undated forecasts provided by the Company indicate that AEP has generated much more recent commodity price forecasts.

The updated forecast provided by the Company shows gas prices starting closer to actual 2016 Henry Hub prices, suggesting that the forecast is relatively recent. While the forecast suggests prices returning close to the Company's BASE trajectory, in general the gas prices are lower through 2030 and in most near-term years are closer to the "Lower Band" than the BASE.

[27] Attachment JIF-7 (JI_DR_Set_4_Q6c.xlsx).

Figure 4. Henry Hub natural gas price gas price forecast from I&M Analysis (June 2015), and as updated (JI DR Set 4 Q6c)



Finally, AEP's recent Kentucky Power Company IRP, filed December 20, 2016 before the Kentucky Public Service Commission states that "the overall [AEP] fundamental forecasting effort was completed in October of 2016."[28] The instant case before the IURC was filed on October 20, 2016, meaning that an updated forecast was developed by, and would have been available to the Company within days of the filing. A delay in filing by a few days could have resulted in a substantially different finding by the Company.

All of these factors strongly indicate that I&M's forecast was outdated at the time this application was completed and, according to more up-to-date information, has substantially outdated gas prices.

Q Would it be appropriate to only assess the Rockport 2 SCR decision on the basis of the Company's "Lower Band" analysis?

A No. The Company's "Lower Band" analysis also assumes that coal prices are substantially lower on a going-forward basis than the Base forecast. In contrast to

[28] Kentucky Power Company 2016 IRP. Section 4.3.1. Excerpt is Attachment JIF-9. Available at: http://psc.ky.gov/pscecf/2016-00413/jkrosquist%40aep.com/12202016110531/KPCO_2016_IRP___Volume_A___Public___Version.pdf

natural gas forwards, the Company's forecast of coal prices from the Powder River Basin (the source of most Rockport coal) is largely unchanged from the June 2015 forecast. This indicates that the coal and gas prices are decoupled, and coal prices have, in the Company's estimation, remained relatively stable while gas prices have fallen.

In general, it is my opinion that the Company's "Lower Band" and "Higher Band" fuel price forecasts are not particularly useful for these types of resource decisions, as the simultaneous higher and lower movement of the gas and coal prices dampens the extent to which a decision is in ratepayers favor or a liability. In this specific case, the "Lower Band" would be inconsistent because it reduces both gas and coal price forecasts, where the Company actually expects only lower gas price futures.

Q Did you update the Company's analysis to account for updated natural gas prices?

A Yes, roughly. A full update to the Company's analysis would have required access to the regional Aurora model run by the Company. The Company uses the Aurora model to generate energy market price estimates given commodity prices.[29] A substantial amount of the cost and revenue of the scenarios examined by the Company rely on the wholesale market price of electricity, a price which is strongly tied to fuel prices. I used Company data to estimate an adjustment to this market price, but my estimates are necessarily relatively rough.

It is notable that in assessing the Company's "more recent" fundamentals forecast, the market price of on-peak energy also fell substantially with the lower gas prices when compared to the June 2015 forecast used by I&M in its October 2016 application.[30]

[29] I&M 2015 Integrated Resource Plan. Section 4.3. Attachment JIF-10.
[30] *See* Attachment JIF-7 (JI_DR_Set_4_Q6c.xlsx).

Q Please briefly describe the nature of the adjustments you made to the Company's analysis.

A There are three elements of the Company's analysis that must be adjusted with changed fuel prices: fuel prices, the cost of market energy procured to serve load, and the revenue from energy sold into the market. To adjust fuel prices, I backed out the cost of fuel procured for the natural-gas-fired combined-cycle replacement units modeled by the Company [31] and substituted the price of fuel from AEO 2017,[32] adjusted using AEP's inflation rate[33] and basis adder.[34]

To adjust the market prices of energy purchased for load and sold by M&I's generators, I estimated an adjusted market energy price (in $/MWh) for load purchases ("Load Cost")[35] and energy sales ("Market Realization").[36] Using the Company's reported Aurora model monthly market and fuel prices,[37] I derived a relationship between average PJM (AEP hub) wholesale market prices (on-peak and off-peak) and monthly Henry Hub natural gas prices, coal prices, carbon dioxide ("CO_2") prices, system average heat rates, and a dummy variable for month.[38] This relationship was extremely robust and indicated that these variables predicted 96 percent of the variance in both on-peak and off-peak monthly wholesale market prices. Substituting AEO 2017 gas prices into these two equations yielded rough market price estimates for the PJM AEP hub. I calculated the extent to which AEP's analysis found Load Cost prices and Market

[31] Derived from individual new build unit fuel costs (JI 3.3 Attachment 1) and the new gas unit heat rate as reported in workpaper I&M_(CONFIDENTIAL)WP_Ex SCW-3_(Alternative Resource Parameters)_102116.xlsx, tab "Ex SCW-3(2)New-Build NG."

[32] AEO 2017 Natural Gas Spot Price at Henry Hub (2016 dollars per million btu). Available at http://www.eia.gov/outlooks/aeo/excel/aeotab_13.xlsx, line 43. Attachment JIF-11.

[33] Annual inflation rate available in I&M Response to JI Data Request Attachment 3-11, tab "Annual Prices," column BB. Attachment JIF-12.

[34] Basis adder calculated as difference between Henry Hub prices as stated in JI3-11 (or IM_WP_Ex SCW-2_(LT Fund Commodity Price Fcsts)_102116.xlsx, tab "Ex_SCW-2 (LT Pricing)") and derived delivered gas price.

[35] *See*, *e.g.*, "Exhibit 4- IM_WP_Ex SCW-4A_Option 1A_BASE Pricing_(CPW Modeling Results Detail)_102116.xlsx" tab "Summary", column AQ.

[36] *Id.* Column AR.

[37] I&M's Attachment to Response to JI Data Request 3-11. Attachment JIF-12.

[38] Relationship derived after adjusting to constant 2016$ using AEP inflation adjustors.

Realization prices reflected on- or off-peak prices and, using that same relationship, predicted revised Load Cost and Market Realization prices.

I believe that this relationship is robust, except at extremely low gas prices. In the first three years of the analysis, the methodology predicts market prices that are unreasonably low, likely because dispatch fundamentally changes at such low gas prices. However, the first four years of the analysis are irrelevant to this analysis as the market purchases and sales from 2016 to 2019 (inclusive) are identical across all cases.

Q What was the outcome of your natural gas price adjustment analysis?

A The impact of the natural gas price update is dramatic, as it impacts the core decisions of the Company's analysis. The lower gas prices, reflected in market prices, increase the relative merit of every option in which Rockport 2 is not maintained over the long term.

Table 3. Relative cost / (savings) of Options 1B, 2, and 2A relative to Option 1A, total CPW (million 2016$), gas price adjustment

	Option 1B (Build SCR, 2022 exit)	**Option 2** (No SCR, 2019 Termination)	**Option 2A** (No SCR, 2019 Term., 2023 NGCC)
As filed, with end-effects	$84	$322	$346
Gas price update, no end-effects	($445)	($431)	($327)

Overall, this adjustment makes it clear that the long-term maintenance of Rockport 2 is unlikely to be favorable for I&M ratepayers. However, it also equalizes the relative merit of Option 1B and Option 2, raising doubts about the clear option value of building the SCR even if I&M can successfully exit the lease in 2022.

5. ANALYSIS ERRONEOUSLY CALCULATES IMPACT OF SHARED-ONGOING-CAPITAL COSTS

Q What are ongoing-capital costs?

A Power plants incur both occasional-capital projects, such as the SCR contemplated in this case, and ongoing-capital projects such as the replacement of turbine, boiler, and balance of plant systems like fuel feed systems, cooling systems, and pumps. As a coal-fired power plant, Rockport will also incur costs to address new regulatory requirements for treatment of wastewater effluent and disposal of coal combustion waste. These capital costs are substantial and, along with labor costs, comprise the bulk of the fixed costs of maintaining a large fossil steam electric plant.

Most large fossil electric plants incur some amount of capital on an annual basis for major maintenance projects, called "ongoing capital costs."

Q What are I&M's erroneous calculations with respect to ongoing capital costs?

A I&M makes two substantial errors in calculating the impact of ongoing capital costs in this analysis, understating the cost of Option 1B by $53 million and overstating the cost of Option 2A by $28 million. These errors are separate in nature.

The first error arises from a mismatch between an explicit Company assumption and its execution with respect to ongoing capital. The Company assumes that a retiring unit would not incur substantial additional capital as it nears retirement—an assumption with which I agree. As a rough estimate, the Company tapers costs, explicitly assuming that three years prior to retirement, the Company would incur only [redacted] percent of the ongoing capital required to keep Rockport 2 operational. The Company further assumes that it would spend only [redacted] percent of otherwise required ongoing capital costs two years prior to the retirement year, [redacted] percent in the year prior to retirement, and zero percent in the retirement year itself. This assumption is memorialized in written text in the Company's workbooks.[39] The pattern is executed correctly in Option 2 (retire in 2019, no SCR) but misapplied in Option 1B (build SCR, exit lease). In Option 1B, the Company models the taper as beginning in 2017 and declining to [redacted] percent in 2019, three years prior to retirement. In 2020 and 2021, the Company models that they spend just [redacted] percent of the required ongoing capital at Rockport 2. This clear inconsistency between the treatment of ongoing capital at Rockport 2 in Option 1B and 2 falsely lowers the cost of Option 1B by $53 million and biases the analysis against Option 2.

The second error seems to be a simple transcription error, in which the Company used the wrong series of numbers for ongoing capital carrying costs at Rockport 2 in Option 2A. In the Company's workpapers for Option 2A, the capitalized cost of ongoing capital at Rockport 2 is given at $4.9 million per year,[40] while in the parallel workpapers for Option 2, the same cost stream is only $1.9 million per year.[41] The disposition of Rockport 2 should be identical in Option 2 and Option 2A, and we are able to verify that the $1.9 million per year of capitalized cost in Option 2 is consistent with the Company's assumptions.[42]

Q Overall, what is the impact of your ongoing capital cost correction?

A I have applied the ongoing capital cost correction incrementally to the fuel price update discussed in the prior section. As shown in Table 4, the ongoing capital adjustment does not impact Option 2, but increases the cost of Option 1B by $53 million and lowers the cost of Option 2A by $28 million.

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[39] [redacted] *See* I&M_(CONFIDENTIAL)WP_Ex SCW-3_(Rockport Unit FOM and OGC Fcst Detail)_102116, tabs "RP2 2019 Retirement OGC" and "RP2 2022 Retirement OGC" lines 82-83.

[40] *See* 7- IM_WP_Ex SCW-4A_SENSITIVITY Option 2A_BASE Pricing_(CPW Modleing Results Detail)_102116, tab "Fixed Costs", cells J11:J35.

[41] *See* 6- IM_WP_Ex SCW-4A_Option 2_BASE Pricing_(CPW Modeling Results Detail)_102116, tab "Fixed Costs", cells J11:J35.

[42] The $1.9 million per year of ongoing capitalized cost in Option 2 is derived in I&M_(CONFIDENTIAL)WP_Ex SCW-3_(Rockport Unit FOM and OGC Fcst Detail)_102116, tab "RP2 2019 Retirement OGC" which is consistent with Option 2, and should also be consistent with Option 2A.

Table 4. Relative cost / (savings) of Options 1B, 2, and 2A relative to Option 1A, total CPW (million 2016$), gas price and ongoing capital correction

	Option 1B (Build SCR, 2022 exit)	**Option 2** (No SCR, 2019 Termination)	**Option 2A** (No SCR, 2019 Term., 2023 NGCC)
As filed, with end-effects	$84	$322	$346
Gas price update, no end-effects	($445)	($431)	($327)
+ ongoing capital correction	($392)	($431)	($355)

Under this correction, Option 2 becomes slightly more favorable than Option 1B by $39 million. While this difference is still small relative to the magnitude of the decisions and swings associated with the corrections, it is indicative that the decision between Option 1B and Option 2 is narrower, or reversed, relative to the Company's contention.

Q Are there any other errors in the Company's treatment of ongoing capital costs?

A Yes. I believe there is another error as well with respect to ongoing capital costs, but this error is swamped in magnitude by the corrections I've described above. This error is with respect to the disposition of shared unit costs between Rockport 1 and Rockport 2, where I&M's analysis effectively assumes that the Company's obligations to shared unit costs decreases as one unit nears retirement, with the effect that the analysis is again biased towards the selection of Option 1B.

Q What are shared unit capital costs?

A Some of the ongoing capital spent at Rockport is attributable to each individual generating unit, such as boiler and turbine components and replacements, as well as fuel feed systems. Other ongoing capital applies to the Rockport property and is shared between the Rockport units, such as the coal pile handling and effluent handling systems. These costs are labeled by the Company as "Unit 0" costs.

I&M evenly allocates Unit 0 costs to Units 1 and 2 in all years in which both units remain operational, and are allocated in their entirety to Unit 1 in all years after which Unit 2 is assumed to retire.[43] Subsequent to this allocation, all costs assigned to Unit 2 tapered towards the retirement date, as I described above. However, in tapering the Unit 2 costs, the Company also tapers the Unit 0 costs assigned to Unit 2. And because Unit 2 tapers more quickly in Option 1B, as described above, Option 1B effectively incurs less shared ongoing capital cost than it should—again biasing the analysis towards Option 1B.

If the Company believes that the retirement of Unit 2 will not affect Unit 0 costs, then Unit 0 costs should also not be affected by the progression of Unit 2 toward retirement. Separately treating Unit 0 costs from Unit 2's tapering of capital costs towards retirement results in a similar finding as above—an increase in Option 1B's costs relative to the other options.

6. ANALYSIS USES UNJUSTIFIED CAPACITY MARKET COSTS

Q Were you able to review the capacity prices forecast that I&M used in the analysis underlying its application?

A Yes, I reviewed I&M's forecasted-capacity prices and found them to be higher than reasonably expected.

Q How does the Company develop the capacity-price forecast?

A For early years, the Company uses auction results in PJM. In this mid-2015 forecast, the Company has auction results for forward years 2016 and 2017. PJM auctions have now cleared through 2020, and thus the Company is missing two to three years of known market prices.

For later years, the forecast is based on the Company's model. The Company states that "capacity values are a discreet output of the AuroraXMP Energy

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[43] Workpaper "I&M_(CONFIDENTIAL)WP_Ex SCW-3_(Rockport Unit FOM and OGC Fcst Detail)_102116," tab "RP Cap Fcst," rows 344 to 354.

Market Model."[44] The Aurora model is a regional-scale capacity expansion model used by the Company to generate market energy prices based on commodity price assumptions. While the Company does not provide a detailed description, these types of models can output a capacity price as the shadow price of meeting a reserve margin requirement.

Using a model of this type to develop capacity price forecasts is difficult and fraught. These models tend to consider capacity in a binary framework—either the system is long, in which case the price is close to zero, or the system is short, in which case the price is close to the marginal cost of building new capacity. That marginal cost of building new capacity is often called "CONE," or the Cost of New Entry.[45]

This binary behavior between low prices and CONE is demonstrated in the Company's capacity price forecast, which quickly jumps from historical capacity prices up to CONE, as I will demonstrate below.

Q What is the problem with estimating CONE as a forward-looking capacity price?

A While CONE may seem like a reasonable hypothetical marginal cost for capacity, it fails to reflect the reasons that capacity is built, and often fails to capture the cost of capacity provided by non-fossil units.

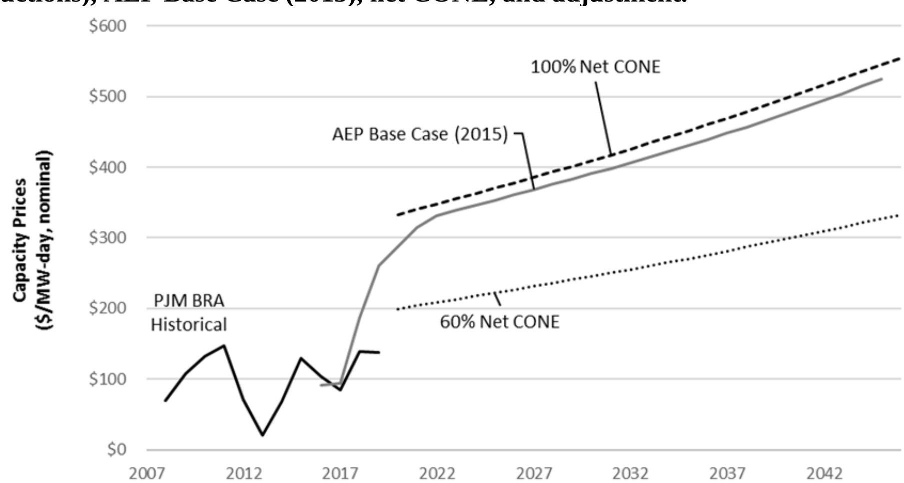
Since the 2007 inception of the capacity market in the PJM zone, called the Reliability Pricing Model ("RPM") Base Residual Auction ("BRA"), the market clearing price of capacity in the greater PJM region (called the "rest of RTO" region), of which I&M is a member, has fluctuated generally below 50 percent of

[44] I&M Response to Data Request No. JI 5-09(b). Attachment JIF-13.
[45] CONE represents the total first- year net revenue (after subtracting variable operation and maintenance cost) that a new generating resource would need to recover its capital and fixed costs, given certain assumptions about future cost recovery over the resource's economic life. CONE is made up of all the capital costs required to build the generating unit, including engineering, procurement, and construction costs, as well as owner costs such as project development, financing fees, and interconnection costs. CONE also includes annual fixed O&M cost. These estimated costs are converted into the annual net revenues that the generation owner would have to earn over an assumed economic life to earn a specific return on capital.

CONE.[46] New energy efficiency and demand response programs, renewable energy resources, and new gas plants built for reasons other than capacity requirements alone have served to depress capacity prices.

The RPM process is conducted three years ahead, with BRA results setting capacity prices in the future. Figure 5 (below) shows the PJM BRA historical prices,[47] net CONE[48] and, closely underneath, the Company's Base case (2015) capacity price assumption as used in the Company's application. It is readily apparent that the Company's assessment effectively assigns the capacity market a price of CONE, despite historical records to the contrary.

Figure 5. PJM capacity prices ($/MW-day). Base Residual Auction (2007-2016 auctions), AEP Base Case (2015), net CONE, and adjustment.



CONE serves as a maximum capacity value. A plant paid over CONE would be made more than whole, a non-efficient outcome. In contrast, however, substantial new capacity has been built and proposed throughout the PJM market region without a guarantee anywhere near CONE prices.

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[46] PJM. "2019/2020 RPM Base Residual Auction Results." Page 1. Available at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-base-residual-auction-report.ashx. Attachment JIF-14.

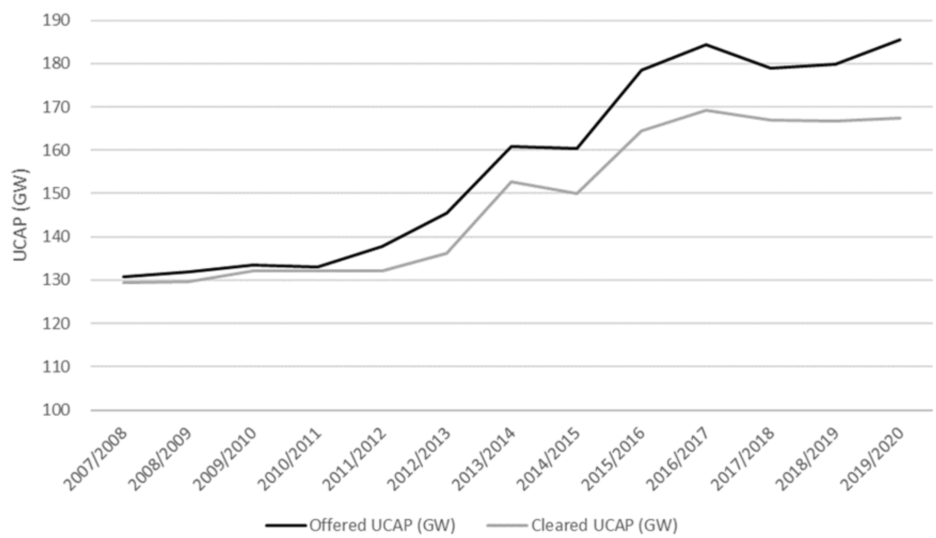
[47] PJM BRA prices for average calendar year = 7/12 first auction year + 5/12 second auction year.

[48] 2019/2020 RPM Base Residual Auction Planning Period Parameters. PJM. February 8, 2016. Table 3. Net CONE for RTO at approximately $300/MW-day. http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-rpm-bra-planning-parameters-report.ashx. Attachment JIF-15.

Q Are capacity margins tightening substantially such that prices might approach CONE soon?

A Not really. PJM publishes the quantity of capacity bid into the BRA, and how much cleared (i.e., is required for PJM's territory). Recent auction results show that considerably more capacity is offered into the RPM market than clear, by a substantial margin (see Figure 6, below).

Figure 6. Base Residual Auction (BRA) results for PJM, offered and cleared unforced capacity (GW)



There is currently a surplus of resources in PJM, including low-cost wind and solar generators, energy efficiency and demand response resources, and new thermal resources. The 2019/2020 RPM BRA cleared 167,306 MW of unforced capacity throughout PJM, yielding a reserve margin of 22.4 percent, which is 5.9 percent higher than the target reserve margin of 16.5 percent.[49] This surplus reserve was "achieved at Capacity Performance prices that are between approximately 33 percent to 60 percent of Net CONE, depending upon the zone

[49] PJM. "2019/2020 RPM Base Residual Auction Results." Page 1. Available at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-base-residual-auction-report.ashx.

comparison, while attracting just over 5,000 MW of new combined cycle gas resources."[50]

This resource surplus was greater in the 2019/2020 RPM BRA than in the previous year's auction, with more than 4,500 MW of additional resources being offered, and a greater number of resources that cleared. "This has the effect of shifting the supply curve down and to the right which would lower (capacity) prices, all else equal."[51]

Q Does AEP have a track record of predicting high capacity prices?

A Yes. In a discovery response, AEP listed every capacity price forecast used in litigated cases between 2012 and the present day. In each and every circumstance, AEP predicted that the year after the BRA result (i.e., four years out), capacity prices would immediately approach CONE. In 2012, AEP predicted that capacity prices in 2016 would be near CONE values ($282/MW-day).[52] Instead, prices have generally remained well below half of that value.

It is notable that prices in the most recent auction (2019/2020), capacity prices fell by 39 percent to $100/MW-day.

Q What is your recommended capacity price forecast for the Rockport analysis?

A As a relatively conservative estimate, I propose a forward capacity price at 60 percent of net CONE, or $180/MW-day (see Figure 5, above), recalling that CONE is a ceiling price, and has never previously been reached.

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[50] *Id.*
[51] PJM. "2019/2020 RPM Base Residual Auction Results." Page 29. Available at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-base-residual-auction-report.ashx. Attachment JIF-14.
[52] Attachment to Discovery Response JI 3-15(d).

Q Has the Company reviewed capacity market results?

A I assume they have, but when queried, Mr. Weaver responded in the negative. Asked to “provide any communications generated by or available to Mr. Weaver with respect to capacity value or price forecast assumptions in PJM from 2014 through the present day,” the Company responded that “Mr. Weaver has neither generated nor received communications concerning PJM capacity values or prices from 2014 through the present day.”[53]

This is confounding and concerning, considering that for a utility so prominently positioned in the PJM region, capacity market prices assuredly must inform some of AEP Fundamental’s group’s decisions. PJM capacity market prices are widely published, reviewed, and discussed amongst utility analysts in the region, and are a critical part of Mr. Weaver’s assessment.

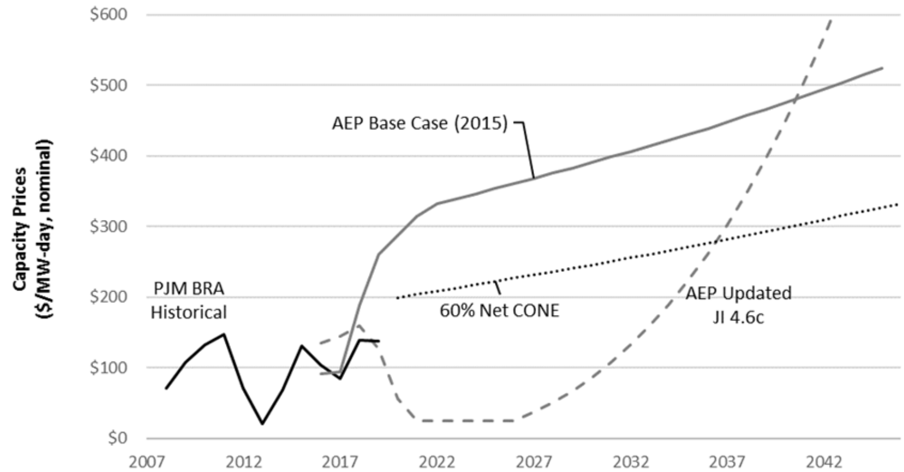
It is also clear from Mr. Weaver’s forecasts that the capacity market results used in this analysis fail to incorporate the last two capacity market auctions, incorrectly assuming capacity prices well above actual established market conditions. Asked why his assessment failed to take into account either the 2018/2019 (August 2015) or 2019/2020 (May 2016) BRA auction results, Mr. Weaver responded that “at the time that the projected capacity values identified in Attachment SCW-2 were established by the AEP Fundamental Analysis group such identified auction results were not available.” This, yet again, points to the failure of the Company to update the analysis with known and knowable data at the time of filing (October 2016).

The one update provided by the Company in response to a discovery request[54] shows a revised capacity price forecast from AEP that effectively bottoms out near a zero cost and only starts rising again in the mid-2030s. This extremely low

[53] I&M Response to JI Data Request 3-15(c). Attachment JIF-16.
[54] I&M Attachment to Response to JI Data Request 4.6c. *See* Attachment JIF-7.

capacity price was used by the Company in AEP's recent Kentucky Power Company 2016 IRP, filed in December 2016. [55]

Figure 7. PJM capacity prices ($/MW-day). Base Residual Auction (2007-2016 auctions), AEP Base Case (2015), 60% CONE adjustment, and AEP updated Base Case (2016).



Q How does your capacity price adjustment impact the outcome of the Company's analysis?

A The capacity price adjustment clearly impacts Option 2A most substantially, reducing the cost of replacing Rockport 2's capacity with market purchases for the interim 2019-2023 period. The capacity price adjustment impacts the other options as well, but to a lesser extent, as the replacement capacity envisioned here is roughly equivalent to the size of Rockport 2.

[55] Kentucky Power Company 2016 IRP. Figure 23. Excerpt is Attachment JIF-17.
http://psc.ky.gov/pscecf/2016-00413/jkrosquist%40aep.com/12202016110531/KPCO_2016_IRP___Volume_A___Public___Version.pdf

Table 5. Relative cost / (savings) of Options 1B, 2, and 2A relative to Option 1A, total CPW (million 2016$), gas price, ongoing capital correction, and capacity price adjustments

	Option 1B (Build SCR, 2022 exit)	**Option 2** (No SCR, 2019 Termination)	**Option 2A** (No SCR, 2019 Term., 2023 NGCC)
As filed, with end-effects	$84	$322	$346
Gas price update, ongoing capital correction, no end-effects	($392)	($431)	($355)
+ capacity price adjustment	($357)	($411)	($407)
Relative to 1B		*($54)*	*($50)*

With this adjustment in place, cumulatively to the other corrections, Options 2 and 2A are almost the same cost. Both Option 2 and 2A continue to show a substantial benefit against Option 1A (over $400 million), and clear Option 1B by a benefit of approximately $50 million. The analysis clearly indicates that the optionality of 1B—building the SCR and then abandoning it in 2022—is not reasonably established, and the long-term benefits of maintaining Rockport 2 are non-existent.

If we substitute the capacity market forecast used by AEP in the Kentucky Power 2016 IRP and disclosed in discovery in this proceeding as AEP's more recent forecast, the differences are even more dramatic, with Option 2A (the market replacement) a far preferred option. In that case, Option 2A clears Option 1A by nearly $500 million and Option 1B by $160 million.

It is notable that the Company's application finds that investing in the SCR and maintaining Rockport 2 provides a substantial long-term benefit over an early termination in 2019—to the tune of $300+ million in savings. Making necessary corrections, updates, and adjustments, all of which would have been readily available to the Company, I calculate that investing in Rockport and maintaining the facility through the indefinite future actually will result in ratepayer losses of about $400 million—or a $700 million swing. Much of this swing is attributable to the Company's failure to update commodity prices in over a year and a half, but other components are either simple mistakes or ill-considered adjustments by the Company that must be corrected. The Commission should closely examine this magnitude of error in assessing I&M's application and future analyses.

7. The Company's Proposal Exposes I&M to Substantial Litigation Risk Under the Lease Agreement

Q What is the substantial litigation risk under the Company's proposal for Rockport 2 in this application?

A I&M has functionally proposed two specific cost savings measures under Option 1A and Option 1B that expose it to substantial risk under the terms of the lease agreement and Consent Decree. My review of the lease and Consent Decree, as a non-attorney, has identified a few provisions that expose I&M to litigation risk. First, under option 1B, I&M intends to reduce ongoing capital investments at Rockport 2, exposing it to liability under the "Event of Default" lease provision. Second, under both Options 1A and 1B, I&M's intention to install a sub-standard SCR exposes it to a possible enforcement action for noncompliance with the Consent Decree or exposes it to liability under the "Event of Default" lease provision.

Q What are I&M's responsibilities under the lease agreement for Rockport 2 with respect to the operability of the unit?

A The Lease Termination Date is 2022. Section 5 of the lease provides that "[u]nless the Lessee has theretofore acquired the Undivided Interest as provided herein, on the Lease Termination Date the Lessee shall (i) surrender possession of the Undivided Interest and the Unit 2 Site Interest to the Lessor …. in the condition and state of repair required by Section 8(a).[56] Section 8(a) states that "[t]he

[56] *See* I&M example lease, JI 3-16a Attachment 1 at pg. 8, Sec. 5. Attachment JIF-18.

Lessee shall cause the Operator to: … (ii) operate, service, maintain and repair Unit 2 and the Common Facilities and replace all necessary or useful parts and components thereof so that the condition and operating efficiency of Unit 2 will be maintained and preserved, ordinary wear and tear excepted, in all material respects … (iii) use, possess, operate and maintain Unit 2 and the Common Facilities in compliance with all material applicable Governmental Actions[57] affecting the Rockport Plant or Unit 2 or the Common Facilities or the use, possession, operation and maintenance thereof; and (iv) otherwise act in accordance with the Operating Agreement.[58] The lease also requires "[t]he Lessee, at its expense (except as provided in Section 8(e)), shall make any Modification required by the Operating Agreement or, subject to Section S(h), by any Applicable Law or Governmental Action.[59] The lease prevents I&M from making any modifications that "will materially diminish the value or utility of Unit 2 or materially reduce its remaining useful life."[60]

Thus, at the Lease Termination Date (in 2022), I&M must return Rockport 2 to the Lessors in a condition and state of repair such that the operating efficiency of Unit 2 is maintained and preserved,[61] and I&M must have made all modifications, at its expense, required by applicable laws or government action.[62]

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[57] "Governmental Action" is defined as "all permits, authorizations, registr·ations, consents, approvals, waivers, exceptions, variances, orders, judgments and decrees, licenses, exemptions, publications, filings, notices to and declarations of or with any Governmental Authority … and shall include, without limitation, all sitings, environmental and operating permits and licenses that are required for the use and operation of Unit 2 and the Common Facilities." I&M example lease, JI 3-16a Attachment 1 at pg. 43. Attachment JIF-18.

[58] *See* I&M example lease, JI 3-16a Attachment 1 at pg. 9-10, Sect. 8. Attachment JIF-18.

[59] *See* I&M example lease, JI 3-16a Attachment 1 at pg. 10, Sec. 8(c). Attachment JIF-18.

[60] *Ibid*.

[61] See I&M example lease, JI 3-16a Attachment 1. Attachment JIF-18.

[62] *Id.* Section 8(c). *Modifications.* "The Lessee, at its expense (except as provided in Section S(e)), shall make any Modification requited by the Operating Agreement or, subject to Section S(h), by any Applicable Law or Governmental Action. In addition, the Lessee, at its expense (except as provided in Section 8(e)), from time to time may make any Modification that the Lessee may deem desirable in the conduct of its business; provided, however that the Lessee shall not have the right to make any such optional Modification that will materially diminish the value or utility of Unit 2 or materially reduce its remaining useful life."

Q Does the lease define what actions would constitute default?

A Yes. The term "Event of Default" is defined to include "fail[ure] to perform its agreements set forth in Section 5," which sets forth I&M's obligations when it relinquishes Rockport 2 back to the lessor, and "fail[ure] to perform or observe any covenant or agreement … to be performed or observed by it under this lease."[63]

Q What happens if I&M fails to return Rockport 2 to the Lessors in full working condition and operating efficiency in 2022?

A I&M would likely default on the Lease. At the "Expiration of Basic Lease Term," I&M can "return the Undivided Interest to the Lessor pursuant to Section 5," if the Company provided notice to the Lessor 18 months before the expiration date of its decision. However, as noted above, failure to comply with Section 5's relinquishment obligations is considered a default. Section 5 requires I&M to "surrender possession of the Undivided Interest and the Unit 2 Site Interest to the Lessor …. in the condition and state of repair required by Section 8(a)," and Section 8(a) requires I&M to "operate, service, maintain and repair" Rockport 2 "and replace all necessary or useful parts and components thereof so that the condition and operating efficiency of Unit 2 will be maintained and preserved" and to operate and maintain Rockport 2 in compliance with all Consent Decrees.

Q If I&M is found to have built a sub-standard SCR that doesn't comply with the Consent Decree, could I&M be considered in default of the lease?

A Yes. I&M is required under the lease to "operate and maintain Unit 2 and the Common Facilities in compliance with all material applicable Governmental Actions," which includes applicable Consent Decrees.[64] "Fail[ure] to perform or

[63] *See* I&M example lease, JI 3-16a Attachment 1, pg. 19, Sec. 15. Attachment JIF-18.
[64] *See* I&M example lease, JI 3-16a Attachment 1, pg. 9-10, Sec. 8 and pg. 43, definition of "Governmental Action." Attachment JIF-18.

observe any covenant or agreement …to be performed or observed by [I&M] under this lease," is considered an "Event of Default."[65]

Q What happens if I&M defaults on the lease?

A It is likely that I&M would have to pay the Stipulated Loss Value. The lease provides that "[u]pon the occurrence of any Event of Default and at any time thereafter so long as the same shall be continuing the Lessor at its option may, by notice to the Lessee, declare this Lease to be in default; and at any time thereafter …the Lessor may … exercise one or more of the following remedies, … as the Lessor in its sole discretion shall elect: …the Lessor may …demand that the Lessee pay to the Lessor …an amount equal to the excess, if any, of (1) Stipulated Loss Value." In December 2022, this Stipulated Loss Value would be [redacted].[66] If an Event of Default were found to have occurred earlier than December 2022, the Stipulated Loss Value would be higher.

The potential for an Event of Default—and the subsequent extraordinary payment—is not contemplated by I&M in its application, but is a possible outcome of Option 1A and a more likely outcome of Option 1B, as modeled by the Company. Options 2 and 2A are free of this particular litigation risk, as these Options invoke Economic Obsolesce,[67] a different set of provisions to terminate the lease prior to the Lease Termination Date.

I'll first address the lease provision that makes Option 1B particularly risky, and then the lease provision and Consent Decree obligation that applies to both Option 1A and 1B.

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[65] *See* I&M example lease, JI 3-16a Attachment 1, pg. 19, Sec. 15. Attachment JIF-18.

[66] *See* IG DR 2-04 Confidential Attachment 1, 85 percent of December 2022 value. This spreadsheet represents the total termination value, which are identical, according to Schedules 2 and 3 of the lease (see JI 3-16a Attachment 1 which is Attachment JIF-18). Attachment JIF-19-C.

[67] *See, e.g.* I&M example lease, JI 3-16a Attachment 1, pg. 18, Sec. 14., which requires that if I&M invokes the "Obsolence Termination" provision it must use best efforts to find another entity to buy its interest in the plant and if it cannot find another buyer, and is not in default, to pay a Termination Value to the Company. Attachment JIF-18.

Q **Why would Option 1B risk a contractual "Event of Default" as modeled by the Company?**

A As I discussed with respect to Section 5 earlier, the Company has modeled a declining obligation to invest in ongoing capital expenditures at Rockport 2 prior to the 2022 exit contemplated in Option 1B. If I&M was the Rockport 2 owner, such a declining schedule would be correct and consistent with a 2022 retirement as the Company ceases investing in high-cost life extension and replacement projects. I&M, however, is not the owner of Rockport 2, and is not entitled to make the unilateral decision to retire the plant in 2022. A declining investment schedule at Rockport 2 leaves I&M exposed to the risk of lease default and associated remedies, which include the possibility of having to pay the Stipulated Loss Value.

In Option 1B, I&M contemplates simply ending the lease at the Expiration of Basic Lease Term, without penalty, in 2022 at the Lease Termination Date.[68] However, this section requires that I&M "return the Undivided Interest to the Lessor pursuant to Section 5," which is inconsistent with the declining ongoing capital investment modeled in this Option.

As Dr. Paul Chodak describes, the lease is already a matter of litigation between I&M and the Lessors,[69] with the subject of that litigation a "claim that AEGCo and I&M failed to exercise prudent utility practices in the maintenance and operation of Rockport Plant, Unit 2."[70]

Q **What types of ongoing capital investments would I&M forgo under Option 1B that might be contradictory to Section 5 of the lease?**

A Like any large fossil boiler, Rockport requires continuous maintenance and replacement of key components to remain reliable and operational. I&M

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[68] *See, e.g.,* Attachment JIF-18 (I&M example lease, JI 3-16a Attachment 1), pg. 17, Sec. 13, the Company could terminate the Lease at the expiration of the Basic Lease Term without having to make an Obsolence Termination.
[69] Direct Testimony of Dr. Paul Chodak, page 9 at 16 to page 11 at 5.
[70] I&M Response to JI Data Request 3-23(a). Attachment JIF-20.

contemplates significant capital expenditures at Rockport Unit 2, besides costs associated with the SCR, between 2017 and 2022. For example, I&M currently contemplates more than [redacted] in major non-environmental capital projects at Rockport 2 between 2017 and 2022, including several major projects on Rockport 2's [redacted][71] With a near-term closure, I&M almost certainly would not invest in some of these projects, opting for short-term repairs that minimize long-term costs.

The Lessors may decide otherwise – that the unit was not slated for near-term closure – and could pursue litigation. A failure to repair or replace key critical components on a timely schedule could risk outages or failures, and increases the risk of future outages.

Moreover, it exposes I&M to the risk of defaulting on the lease. I&M is likely at risk of default if I&M decides not to renew the release and relinquishes possession and use of Rockport 2 to the Lessor but fails to relinquish it "in the condition and state of repair required by Section 8(a)," which requires I&M to "operate, service, maintain and repair" Rockport 2 "and replace all necessary or useful parts and components thereof so that the condition and operating efficiency of Unit 2 will be maintained and preserved" and to operate and maintain Rockport 2 in compliance with all Consent Decrees. If actually carried out, the scaling back of capital investments on Rockport 2 from 2017 to 2022 assumed in the Option 1B modeling could likely subject the Company to default risk.

Overall, I believe that Option 1B, as modeled, is not consistent with the lease and bears a significant risk of litigation from the Lessors and could result in an Event of Default. Such an event could result in additional penalty costs of [redacted] in 2022.

[71] Workpaper "I&M_(CONFIDENTIAL)WP_Ex SCW-3_(Alternative Resource Parameters)_102116," tab "RP Cap Fcst."

Q How should Option 1B be modified to reduce litigation risk?

A The costs of Option 1B should reflect an assumption that I&M must return Rockport 2 to the Lessors in a state of good repair and fully operable. This requires that Option 1B be modeled with *no reduction* in ongoing capital expenditures at Rockport 2. Correcting Rockport 2 on-going capital costs so that they do not taper off at all increases the cost of Option 1B by more than $120 million relative to the Company's analysis.

Q Options 2 and 2A also contemplate the reduction of ongoing capital prior to early lease termination in 2019. Are these options subject to the same litigation risk?

A No. Under Options 2 and 2A, I&M would declare that Rockport is economically obsolete and provide a termination notice to the Lessors.[72] The process here is considerably different than an Event of Default for failure to relinquish possession and operation of Rockport 2 in a manner that is not fully operating and efficient. In this case, the Lessee (I&M) would seek bids to acquire the unit, potentially including themselves, and pay the sale price plus any differential up to the Termination Value.[73] While I&M still pays a Termination Value (and in this case, the Termination Value in 2019 is higher than the Stipulated Loss Value in 2022), it is exempted from the requirement that the unit be returned in good condition and full state of repair. Thus, irrespective of if I&M acquires the Unit 2 at zero cost to retire it, or another party acquires Rockport 2, I&M does not face the same litigation risk. Instead, it simply pays the Termination Value (less any sales proceeds), and exits the lease.

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[72] *See* Attachment JIF-18 (I&M example lease, JI 3-16a Attachment 1), pg. 18,Sec. 14(a). *Obsolescence Termination*; *Termination Notices.* "If the Lessee shall have determined that Unit 2 is economically obsolete (including, without limitation, by reason of the amount of expenditures required to comply with Section 8) or surplus to the needs of the Lessee, the Lessee shall have the option to terminate this Lease…"

[73] *Id.*, pg. 18,Sec. 14(b). *Events on Termination Date.* "On the Termination Date the Lessor shall (but only upon receipt of the sale price and all additional payments specified in the next sentence) effect a Transfer for cash to the Person that submitted the highest bid prior to such date,.." and "…on such Termination Date the Lessee shall pay to the Lessor … (i) an amount equal to the excess, if any, of the Termination Value, determined as of such Termination Date, over the Sale Proceeds…"

Q You also stated that the Company's proposal to install a "sub-standard" SCR at Rockport 2 exposes I&M to litigation risk under the lease. Why is the proposed SCR sub-standard?

A The Company's SCR proposal would cause the NOx emission rate at Rockport 2 to decrease from 0.25 lb/MMBtu to 0.14 lb/MMBtu between 2019 and 2020, for a reduction of 44 percent.[74] This reduction is substantially smaller in magnitude than achieved by other contemporary SCR systems. For example, a recent EPA report states that coal-fired SCR systems "are often designed to meet control targets of over 90 percent."[75] Furthermore, the Company's own analysis proposes to use the SCR more aggressively starting in [redacted], and thereby reduce the NOx emission rate by [redacted] relative to the current rate.[76]

Q Has the Company considered installing an SCR system that achieves greater emission reductions than those anticipated under its current proposal?

A Yes. Although the Company proposes to initially operate the SCR with only one or two catalyst layers, it specifically requested that the SCR system be designed to accommodate four catalyst layers.[77] According to the Company's project specification, "[t]he remaining catalyst will be installed at a later date."[78] Installing additional layers of catalyst would allow the SCR to achieve deeper reductions, consistent with the current industry standard.

Q When would the remaining catalyst be installed?

A Evidently, this installation of additional catalyst would occur [redacted]

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[74] Workpaper "I&M_(CONFIDENTIAL)WP_Ex SCW-3_(Alternative Resource Parameters)_102116," tab "Ex SCW-3(1)Rockport," cells I54:I55.

[75] John L. Sorrels et al. U.S. EPA. May 2016. EPA Air Pollution Control Cost Manual Chapter 2: Selective Catalytic Reduction, at 2-2. Available at https://www3.epa.gov/ttn/ecas/docs/SCRCostManualchapter7thEdition_2016.pdf. Attachment JIF-21.

[76] Workpaper "I&M_(CONFIDENTIAL)WP_Ex SCW-3_(Alternative Resource Parameters)_102116," tab "Ex SCW-3(1)Rockport," cells I54, I64.

[77] Direct Testimony of Franklin R. Pifer, p.5 at 4-6; JI_DR_Set_3,_Q3.17d_Attachment_1, at 2.1.

[78] I&M's Attachment to Response to JI Data Request 3-17(d) (JI_DR_Set_3,_Q3.17d_Attachment_1) at 6.1.1. Attachment JIF-22.

[redacted].[79]

Q What are the risks associated with installing an SCR system that achieves approximately half of its emission reduction potential?

A If the Company follows its proposed plan to install and operate an SCR system that achieves emission reductions of only 45 percent from 2020 through [redacted], it will be exposing itself to at least two separate litigation risks.

First, one or more of the parties to the Consent Decree requiring the installation of SCR at Rockport 2 may seek to sue the Company under the theory that the Consent Decree requires the installation of a more complete SCR system. Indeed, the Consent Decree requires that the Company "install and Continuously Operate SCR" on Rockport 2 by December 31, 2019.[80] The Consent Decree defines "Continuously Operate" to operate a unit "so as to minimize emissions to the greatest extent practicable.[81] I do not speak for potential litigants, but note the potential risk that parties to the Consent Decree may find the Company's proposal for a one- or two-layer system inconsistent with the requirement.

As a second risk, the Rockport 2's Lessors may sue the Company under the theory that the Company has not taken sufficient action to ensure that Rockport 2 remains legally and practically operable. As I noted above, I&M is required under the lease to "operate and maintain" Rockport 2 "in compliance with all material

[79] Workpaper "I&M_(CONFIDENTIAL)WP_Ex SCW-3_(Alternative Resource Parameters)_102116," tab "Ex SCW-3(1)Rockport," cells I54, I64.
[80] Consent Decree between United States of America and State of New York vs. American Electric Power Service. Civil Action No C2-99-1250. Exhibit JCH-1. Pages 20-21.
[81] 14. "Continuously Operate" or "Continuous Operation" means that when an SCR, FGD, ESP, or Other NOx Pollution Controls are used at a Unit, except during a Malfunction, they shall be operated at all times such Unit is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for such equipment and the Unit so as to minimize emissions to the greatest extent practicable."

applicable Governmental Actions," which includes applicable Consent Decrees,[82] and failure to perform an obligation under the lease is considered an "Event of Default."[83] If there is an Event of Default, the Lessor has the discretion to pick from a number of available remedies, which include making I&M pay the Stipulated Loss Value.[84] In December 2022, this Stipulated Loss Value would be [redacted]

Q What additional capital expenditures would be required to achieve an [redacted] NOx emissions reduction in 2020?

A Achieving the full potential SCR emission reductions would require, at a minimum, the installation of additional induced draft fans and two additional catalyst layers.[85] The Company estimates that installing sufficient induced draft fans to enable full-scale SCR operation would cost $30 million.[86] The Company has also estimated that installing two catalyst layers costs [redacted].[87] Therefore, I expect that the total increased capital to install a four-layer SCR would increase the costs of this project by approximately [redacted].

Q What other expenditures would be required to achieve an [redacted] NOx emissions reduction from 2020 onward?

A Achieving the full potential SCR emission reductions would require increased expenditures on consumables. The Company's analysis indicates that achieving

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[82] *See* Attachment JIF-18 (I&M example lease, I&M Response to JI Data Request 3-16a Attachment 1), pg. 9-10, Sec. 8 and pg. 43, definition of "Governmental Action."
[83] *See* Attachment JIF-18 (I&M example lease, I&M Response to JI Data Request 3-16a Attachment 1), pg. 19, Sec. 15.
[84] *See* Attachment JIF-18 (I&M example lease, I&M Response to JI Data Request 3-16a Attachment 1), pg. 17, Sec. 16(iv)(A).
[85] Direct Testimony of Franklin R. Pifer, at 5.
[86] I&M Response to JI Data Request 5-04(d). Attachment JIF-23.
[87] Attachment FRP-4 to Pre-Filed Direct Testimony of Franklin R. Pifer.

an [redacted] emissions reduction would require approximately [redacted] the level of 2020 consumable expenditures assumed in the Company's analysis.[88] Presumably, the use of additional catalyst layers would also lead to increased fixed operations and maintenance costs. However, I have not attempted to quantify that impact.

Q Please summarize your analysis with respect to the litigation risks emerging from the Company's proposal.

A The potential harm resulting from additional litigation from the Lessors is substantial and highly relevant to this case. I assess that the Company's current outlook for reduced capital spending at Rockport 2 prior to the expiration of the lease in 2022 as modeled in Option 1B, and the failure of the Company to seek to install an SCR capable of "minimiz[ing] emissions to the greatest extent practicable" exposes the Company to substantial litigation risk which should not be imparted upon ratepayers. In order to minimize the litigation risk, the Company would have to pursue full-use equivalency capital expenditures at Rockport 2 and install a four-layer system SCR, if pursuing either Option 1A or Option 1B. Consequently, the analysis used by the Company should be substantially adjusted.

I calculated the effect on the Company's analysis of maintaining ongoing capital in the incorporating the previously described incremental capital and consumable costs associated with a full-scale SCR system, the results of which are shown in Table 6, below.

[88] Workpaper "I&M_(CONFIDENTIAL)WP_Ex SCW-3_(Alternative Resource Parameters)_102116," tab "Ex SCW-3(1)Rockport," cells O55, O64.

Table 6. Relative cost / (savings) of Options 1B, 2, and 2A relative to Option 1A, total CPW (million 2016$), gas price, ongoing capital correction, capacity price, and litigation risk adjustments

	Option 1B (Build SCR, 2022 exit)	**Option 2** (No SCR, 2019 Termination)	**Option 2A** (No SCR, 2019 Term., 2023 NGCC)
As filed, with end-effects	$84	$322	$346
Gas price update, ongoing capital correction, capacity price adjustment, no end-effects	($357)	($412)	($412)
+ minimized litigation risk	($313)	($482)	($482)
Relative to 1B		*($168)*	*($168)*

The costs of both 1A and 1B go up, shrinking the differential between 1A and 1B. However, since the costs of Options 2 and 2A do not adjust, the gap between these Options and 1A and 1B opens substantially.

While the Company portrays Options 1A and 1B as lower cost and maintaining optionality, these results indicate that the Company's outdated analysis fails to convey the very tangible costs and risks associated with maintaining Rockport. Indeed, the certainty of terminating the lease in 2019 at a known cost appears far more attractive—both lower cost and lower risk—than maintaining the plant in a manner inconsistent with its legal obligations on the off chance that the Lessors will not litigate and that market prices will recover significantly in two years.

8. ANALYSIS FAILS TO ASSESS REASONABLE RENEWABLE ENERGY REPLACEMENT COSTS

Q Have you reviewed the Company's renewable resource cost assumptions?

A Yes, I have reviewed the Company's assumptions regarding the cost of solar and wind energy, and I have concluded that these assumptions are outdated, leading to higher than reasonable renewable energy costs.

Q What is the basis for your contention that the Company's renewable cost assumptions are outdated?

A My grounds for believing the Company's assumptions are outdated and exaggerated include evidence from both the Company's own updated cost projections and external publications.

In its analysis, the Company assumed that its most cost-effective wind resource options would cost [redacted]/MWh in levelized terms in 2017, with the cost gradually increasing thereafter.[89] In a discovery response, the Company provided its most recent wind cost projections, under which wind resources cost [redacted]/MWh in 2018 (a 25 percent decrease from the costs assumed by the Company in its analysis).[90] Recent publications indicate that even the Company's updated projections may over-state the cost of wind. A widely cited recent report by Lazard puts the current levelized cost of wind between $14/MWh and $48/MWh, with Indiana's Midwestern region at the lower end of that range.[91]

The Company's assumptions also overstate the cost of solar energy. The Company's analysis assumes the 2017 levelized build cost of utility-scale solar energy to be [redacted]/MWh.[92] However, the Company's most recent solar cost assessment projects a 2018 installation cost of [redacted]/Watt,[93] or approximately [redacted]/MWh (a nearly 50 percent decrease from the costs assumed by the Company in its analysis), with the installation cost continuously declining over time.[94] More recent assessments indicate that the upfront cost of utility-scale solar energy has already declined below the 2018 levels contemplated in the Company's latest

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[89] Workpaper "I&M_(CONFIDENTIAL)WP_Ex SCW-4_(Plexos_Wind bundles performance & cost)_102116.xls."
[90] I&M's Confidential Attachment to Response to JI DR 4-15(d) (CONFIDENTIAL_Attachment_JI_4-15(d).pdf). Attachment JIF-24-C.
[91] Lazard. December 2016. Lazard's Levelized Cost of Energy Analysis – Version 10.0. Available at https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf. Attachment JIF-25.
[92] Workpaper "I&M_(CONFIDENTIAL)WP_Ex SCW-4_(Plexos_Solar Bundles performance & cost)_102116.xls."
[93] I&M's Confidential Attachment to Response to JI DR 4-15(e) (CONFIDENTIAL_Attachment_JI_4-15(e).pdf). Attachment JIF-26-C.
[94] Author's estimate using NREL Annual Technology Baseline (ATB) Spreadsheet – 2016 Final. http://www nrel.gov/docs/fy16osti/66944-DA.xlsm

forecast. Lazard reports that the capital cost of utility-scale solar is currently in the range of $1.30/Watt to $1.45/Watt.[95]

Q How would using updated renewable cost assumptions impact the Company's analysis?

A Using updated renewable cost assumptions would make it more likely that the Company's modeling analysis would select more low-cost renewables as part of the combination of resources used to replace Rockport 2 in the scenarios in which Rockport 2 retires. These cost projection adjustments would have the impact of making Option 2 more cost-effective relative to Option 1B, and Option 1B more cost-effective relative to Option 1A. This is not to say that renewable resources would fully replace the energy and capacity provided by Rockport 2. However, updated renewable cost assumptions could only decrease the cost of the Company's scenarios, and may lead the Company to conclude that its most cost-effective option includes the construction of more renewable resources and fewer fossil fuel resources than previously believed.

9. Conclusions and Recommendations

Q Please summarize your assessment of the Company's application.

A The Company has presented an application in which it seeks authorization to build an SCR at Rockport 2, despite the admittedly marginal economics of the unit. The Company's application rests on the assurance that such a move preserves optionality, suggesting that the Company doesn't need to decide whether to renew the lease in 2022 until later and implying that it will likely decide to renew the lease and continue to operate the plant for another 30 years. Such an analysis is likely to result in the continued use after the lease's expiration.

The Company was only able to find that maintaining Rockport 2 in the long-term would be reasonable because it erroneously relied on questionable end-effects

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[95] Lazard. December 2016. Version 10.0. Attachment JIF-25.

analysis. Mr. Weaver's analysis unreasonably assumes that the Company could maintain Rockport 2 and realize all of the energy benefits of Rockport 2 without facing any capital costs at the unit after 2045 – a distorted, erroneous, and misleading use of end-effects. Removing this flawed end-effect analysis and simply assessing the Company's application through the 2016-2045 analysis period indicates that Rockport 2 is unlikely to be a reasonable and prudent decision over the extended period. This means that, even under the Company's optimistic scenario, Rockport 2's SCR is likely to become a stranded asset – either absorbed by ratepayers or litigated with the Lessors in 2022.

The Company's economic analysis is also seriously outdated, relying on year-and-half-year-old data (June 2015), which is neither reflective of current projections, nor more recent forecasts produced by the Company and even used by AEP in other jurisdictions. At a minimum, the Company's gas, market power prices, and capacity forecasts are out of date. And even though the Company has assessed new gas and market prices, which would have called its conclusion into question, the Company failed to provide this Commission the updated forecasts or update its internal analysis. The Company's reliance on outdated forecasts biased the results in favor of its preferred outcome. Astoundingly, the director of AEP's resource planning desk—who conducts analysis on behalf of multiple AEP companies across eleven states—claims to have not reviewed basic competitive market information in three years.[96]

The Company's assessment of the costs faced for ongoing capital expenditures at Rockport 2 prior to a potential 2022 retirement are internally inconsistent, ultimately biased towards the selection of its preferred alternative, and would expose the Company to substantial litigation risk. In Option 2A, the Company's numbers are simply wrong.

[96] I&M's Response to JI Data Request 3-15(c). *See* Attachment JIF-16.

Finally, the Company's strategy to build a sub-standard SCR places the Company at litigation risk from the Rockport 2 owners (Lessors) and parties to the Consent Decree. The cost of losing such litigation to the Lessors overwhelms almost all the ostensible benefits and "optionality" preserved by granting the Company's request. While the costs of simply building an appropriate SCR and maintaining Rockport 2 are relatively smaller than the potential litigation risk penalties, they are large enough to alone effectively render the decision to retrofit uneconomic and ill-considered.

Table 7 below shows the relative costs (positive) and benefits (negative) of any other route aside from retrofitting and maintaining Rockport 2. Taking into account simple corrections and updates to the Company's analysis, we see that Rockport 2's SCR does not provide beneficial optionality and imposes substantial risk on the Company.

Table 7. Relative cost / (savings) of Options 1B, 2, and 2A relative to Option 1A, total CPW, across all adjustments (million 2016$). Note, columns are incremental.

	As filed, w/ end-effects	As filed, removed end-effects	+Gas Price Update	+Ongoing CapEx Adj.	+Capacity Price Adjustment	+Minimized Litigation Risk
Option 1B (SCR, 2022 exit)	$84	($84)	($445)	($392)	($357)	($314)
Option 2 (No SCR, 2019 termination)	$322	$169	($431)	($431)	($411)	($481)
Option 2A (No SCR, 2019 termination, 2023 replace)	$346	$176	($327)	($355)	($407)	($478)

Indeed, my assessment of the Rockport 2 SCR indicates that the prompt divestment from Rockport 2 ahead of the SCR requirement is beneficial for I&M's customers and provides a known, low risk exit from the power plant. The analysis indicates that under reasonable expectations of market conditions, there is no specific benefit to replacing Rockport 2 immediately, thus opening an attractive avenue to seek cost effective – and potentially far more sustainable – replacement energy options for the utility.

I estimate that ratepayers will see approximately a $165 million benefit by exiting the Rockport 2 lease in 2019 (Options 2 and 2A) relative to building the SCR and exiting in 2022 (Option 1B). Ratepayers could see a nearly half-billion dollar benefit (using today's commodity price forecasts) by avoiding maintaining Rockport through the long run (Option 1A).

Q How do you recommend this Commission proceed?

A My primary recommendation will be for the Commission to deny the CPCN on the basis that neither of the options examined by the Company for the installation of SCR are candidates for a least cost, least risk, or reasonably calculated risk for ratepayers. This recommendation is strongly held.

Ideally, this Commission should require I&M to file an updated analysis utilizing current market projections for gas, energy, and capacity, remedying inconsistencies, and addressing the other concerns I have raised. Only under such a circumstance will the Commission have a complete record.

However, I also recognize that the SCR project is on a relatively tight deadline, and in filing a late application, the Company has substantially disadvantaged the Commission and intervenors prudence review. While the Commission should not countenance to such conduct, the Commission still must make a decision based on the best possible information. Therefore, I propose an alternate series of recommendations that while allowing the project to continue nevertheless require the Company to update their analysis, allow the Commission the opportunity for review, and provide the Commission the opportunity to hold back future funds if it is determined that the Company has proceeded against the best interests of ratepayers. I believe that it is also important to hold the Company to the basis of its analysis used to justify this decision. Therefore, I make a series of recommendations by which the Company bears responsibility for inappropriate litigation risk from both Consent Decree signatories as well as the Lessors.

Q What are your recommendations to this Commission?

A Based on my assessment of the Company's CPCN application for the installation of SCRs at Rockport 2, I have the following recommendations:

1. That the Commission should deny the CPCN on the basis that neither of the options examined by the Company for the installation of SCR are least cost or least risk for ratepayers, and require that I&M expediently file a plan for the replacement of the capacity and energy requirements otherwise met through Rockport 2;

2. That in the alternative, the Commission conditionally approve the CPCN pursuant to the following:

    a. That I&M maintain separate accounting for the costs of the SCR and supporting balance of plant activities, and that this Commission maintain the ability to adjust the rider at any time prior to 2019 following from the findings of the analysis immediately below;

    b. That I&M conduct, prior to signing a notice to proceed or other release to major SCR contractors, an updated analysis of the same structure as that conducted in this analysis with contemporary load, fuel, and other market price forecasts, and submit such analysis to this Commission by April 2017;

    c. That intervenors be afforded the opportunity to review such analysis, including confidential materials, and submit comments or testimony back to this Commission by October 2017;

    d. That I&M file with the Commission a request for approval to exit or renew the lease at Rockport at least one year prior to informing the lessor as to whether I&M will renew or exit the lease so that the Commission, Staff, and interested intervenors can review through a contested case proceeding. Such request should fully evaluate the costs and benefits of maintaining or exiting the lease based on up-to-date market forecasts, and assess all cost effective alternative options, including energy efficiency, renewable energy, and market purchases;

e. That I&M shareholders bear full responsibility for any and all litigation fees and penalties resulting from any non-compliance with the Consent Decree;

f. That I&M shareholders bear full responsibility for any and all litigation fees and penalties resulting from any breach of the lease;

g. That to prevent piecemeal recovery in the event of successful litigation, I&M be restricted to the recovery of a fixed percentage deadband around the $137.1 million capital costs estimate for the SCR; and

h. That I&M be required to aggressively pursue all cost-effective energy efficiency and renewable energy options in advance of the lease termination date of 2022.

Q Does this conclude your testimony?

A It does.

VERIFICATION

I, Jeremy I. Fisher, PhD, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

__________________________________   February 3, 2017

Jeremy I. Fisher, PhD   Date