Kentucky Power Company
KPSC Case No. 2019-00389
Commission Staff's First set of Data Request
Dated January 17, 2020

DATA REQUEST

KPSC 1_1 Refer to the Direct Testimony of Debra L. Osborne (Osborne Testimony), pages 3-4. State whether Rockport Unit 2 is equipped with low NOx burners and an over air fire system similar to Rockport Unit 1.

RESPONSE

Yes. Rockport Unit 2 is equipped with low NOx burners and an overfire air system similar to Rockport Unit 1.

Witness: Debra L. Osborne

DATA REQUEST

KPSC 1_2 Refer to the Osborne Testimony, page 4. State the number of reactor modules and catalyst layers per reactor module.

RESPONSE

The Rockport Unit 2 SCR has three reactors. Each reactor is designed to accommodate four catalyst layers. The reactors will initially operate with two layers.

Witness: Debra L. Osborne

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DATA REQUEST

KPSC 1_3 Refer to the Osborne Testimony, page 5. Explain whether any existing plant equipment will need upgrades in association with the Rockport Unit 2 selective catalytic reduction (SCR) project.

RESPONSE

The existing plant equipment upgrades associated with the Unit 2 SCR project, whose costs were included in the Company's $233.5 million total cost estimate, include the following:

- Boiler house structural steel reinforcement to accommodate the additional loads of the SCR ($11.5M)
- Air heater basket media upgrade to include cleaning capability required to minimize pluggage of the SCR ($4.5M)
- Distributed Control System upgrade to incorporate control of the Unit 2 SCR and ammonia delivery system ($3.8M)
- Continuous Emissions Monitoring System will be modified to support the Unit 2 SCR with the addition of upgraded NOx probes and analyzers, and ammonia slip monitors ($1.4M)
- Instrument air compressor capacity upgrade to accommodate the increased load requirement of the Unit 2 SCR ($1.0M)
- The plant electrical distribution system upgrade to provide for the electrical loads associated with the new Unit 2 SCR ($0.7M)
- Plant Announcement and Emergency Alert System upgrades to expand the coverage area to include the new U2 SCR ($0.2M)

Witness: Debra L. Osborne

DATA REQUEST

KPSC 1_4 Refer to the Osborne Testimony, page 6. Explain the effect of the Rockport Unit 2 SCR project on the Rockport Plant ammonia inventory and allowance plan.

RESPONSE

Osborne:
The Rockport plant has two 90,000 gallon storage silos for holding anhydrous ammonia (AA). Both silos were in place prior to construction of the Unit 2 SCR, and have the capability to provide AA to the SCRs on both Units 1 and 2. Although the addition of the Unit 2 SCR will increase consumption of AA, it will not increase the amount of AA inventory required to be maintained or the need for storage capacity.

Spitznogle:
The installation of the SCR on Rockport Unit 2 will reduce NOx emissions and the consumption of annual and seasonal NOx allowances associated with the Cross State Air Pollution Rule. The reduction in allowance consumption lessens the likelihood that Kentucky Power will be required to purchase allowances for NOx compliance. The Company anticipates meeting its United States Environmental Protection Agency (USEPA) NOx compliance obligations for Rockport through a combination of operating its environmental control equipment, including the Unit 2 SCR, and use of new (zero-cost) allowances allocated by the USEPA each year.

Witness: Debra L. Osborne
Witness: Gary O. Spitznogle

DATA REQUEST

KPSC 1_5 Refer to the Osborne Testimony, pages 8-9, regarding the installation of the SCR system at Rockport Unit 2 being the reasonable least-cost alternative to meeting Indiana Michigan Power Company's (l&M) capacity and energy obligations. Explain whether an economic analysis was conducted to determine whether the Rockport Unit 2 SCR was the reasonable least-cost alternative associated with Kentucky Power's 15 percent share of the Rockport Unit's capacity and energy. If an economic analysis was performed, provide a copy of that analysis. If none was performed, explain why not.

RESPONSE

In-depth analyses were performed in connection with I&M's filing for a Certificate of Public Convenience and Necessity (CPCN) in Indiana Utility Regulatory Commission (IURC) Cause No. 44871 and in support of I&M's 2019 application to adjust its electric rates in Michigan in Michigan Public Service Commission (MPSC) Case No. U-20359.

The Rockport Unit 2 SCR CPCN analysis demonstrated that for I&M's 85% share of Rockport Unit 2 costs, the SCR retrofit is $239 million less expensive than terminating the Rockport Unit 2 lease as of January 1, 2020. A copy of the testimony and analysis submitted in the Rockport Unit 2 SCR CPCN case is attached as KPCO_R_KPSC_1_5_Attachment1. In its March 26, 2018 Order approving the Rockport Unit 2 SCR CPCN, the IURC found that "the SCR retrofit is the reasonable least-cost compliance option, even if it is only in service for the benefit of I&M customers through the end of the original lease term" and that "[s]ubstantive evidence show[ed]" that the SCR retrofit "is a reasonable least-cost alternative to meeting I&M's capacity and energy obligations." IURC Order at pg. 32. A copy of the IURC's Order is attached as KPCO_R_KPSC_1_5_ Attachment2.

In its 2019 Michigan rate case, which was based upon more recent forecast information and assumed a later lease termination date, I&M's analysis demonstrated that, for I&M's 85% share of Rockport Unit 2 costs, the SCR retrofit is $141 million less expensive than terminating the Rockport Unit 2 lease as of June 1, 2020.

It is reasonable to conclude based on these analyses that if the installation of the Rockport Unit 2 SCR was the least-cost option for I&M's 85% share, it would also be the least-cost option for Kentucky Power's 15% share of the same unit. In order to confirm this conclusion, Kentucky Power is preparing, and will supplement this response with, an economic analysis specific to its 15% share.

Witness: Mark A. Becker

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.**

SUBMISSION OF DIRECT TESTIMONY OF
<u>SCOTT C. WEAVER</u>

Indiana Michigan Power Company, by counsel, hereby submits the direct testimony and attachments of Scott C. Weaver.

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CERTIFICATE OF SERVICE

The undersigned certifies that the foregoing was served upon the following via electronic email, hand delivery or First Class, United States Mail, postage prepaid this 21st day of October, 2016 to:

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EXHIBIT I&M-________

STATE OF INDIANA

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

SCOTT C. WEAVER

ON BEHALF OF

INDIANA MICHIGAN POWER COMPANY

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

I. INTRODUCTION

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

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

II. BACKGROUND

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

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

I have over 35 years of experience with AEP. I was employed by AEPSC in 1980 as an Associate Forecast Analyst in the Controllers

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

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

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

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS REGULATORY COMMISSION?

A. Yes. I offered testimony before this Commission in 2013 on behalf of the Company in Cause No. 44331, which sought a certificate of public convenience and necessity (“CPCN”) for the installation of dry sorbent injection ("DSI") technology and associated equipment at the Company's Rockport Plant. Most recently, I offered testimony on behalf of I&M in Cause No. 44523; which also sought a CPCN for the installation of selective catalytic reduction ("SCR") technology for Rockport Unit 1. In addition, over the last ten years I will have offered resource planning-related testimony on behalf of AEP operating company affiliates before eight other state commissions: Arkansas, Kentucky, Louisiana, Michigan, Oklahoma, Texas, Virginia, and West Virginia.

III. PURPOSE OF TESTIMONY

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

A. The purpose of this testimony is to present economic analyses performed on behalf of the Company regarding installation of SCR technology on Rockport Unit 2. In particular, my testimony will:

1) evaluate the cost and feasibility of an option to retire and replace Rockport Unit 2, an assessment required by Ind. Code § 8-1-8.7-3(b)(7);

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

3) affirm that the analysis undertaken assessing these Rockport Unit 2 disposition options is consistent with I&M's 2015 Integrated Resource Plan ("IRP") submitted to this Commission on November 2, 2015; and

4) discuss the results of these economic modeling analyses and the determination that a near-term decision to retrofit Rockport Unit 2 by December 31, 2019 with SCR technology and associated equipment for the reduction of nitrogen oxides (“NO_X”) is reasonable and would further a course of action around this unit that could ultimately save I&M and its customers over $300 million versus an option that would not perform that retrofit.

Q. ARE YOU SPONSORING ANY ATTACHMENTS?

A. Yes. I am sponsoring the following attachments:

- Attachment SCW-1 – Overview of resource planning-related criteria considered in the analyses.
- Attachment SCW-2 – Key long-term fundamental commodity pricing projections used in the analyses.
- (CONFIDENTIAL) Attachment SCW-3 – Major modeling input costs and operating parameters for unit disposition options.
- Attachment SCW-4-1 and SCW-4-2 – Summary of Rockport 2 unit disposition alternative economic analyses over the long-term life cycle study period evaluated, all under unique commodity pricing scenarios (Attachments SCW-4A through SCW-4E).
- Attachment SCW-5 – Summary of Rockport 2 unit disposition alternative analyses results examined over a shorter timeframe which would demonstrate the significant optionality afforded by retrofitting the unit with SCR technology prior to the possible future installation of a dry scrubber by December 2028, or prior to the potential return of the unit to its Lessors by December 2022.
- Attachment SCW-6 – A comparison of economic analyses that assessed possible Rockport Unit 2 disposition alternatives included in I&M’s recently-submitted 2015 IRP.

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

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

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

A. Attachment SCW-1 offers a broader overview of some of the other resource planning-related criteria that are necessarily introduced and considered as part of this evaluation of alternative options surrounding Rockport Unit 2, but that largely serve as a backdrop. The following direct testimony focuses more specifically on the discrete economic evaluations performed that led to the Company's conclusions and recommendations.

IV. ROCKPORT UNIT 2 DISPOSITION OPTIONS

Q. WHAT ALTERNATIVES WERE ANALYZED WITH RESPECT TO THE DISPOSITION OPTIONS FOR ROCKPORT UNIT 2?

A. As represented on the following **TABLE 1**, two alternative options—with one of those alternatives posing two sub-options—were modeled with respect to I&M's disposition options associated with the Rockport Plant and, specifically, Rockport Unit 2:

TABLE 1

OPTION #1 - Install SCR on Rockport Unit 2

Option #1A: Retrofit Rockport Unit 2 with SCR technology and associated equipment (“Rockport Unit 2 SCR Project”) by December 31, 2019, and enter into a Rockport Lease renewal arrangement for Unit 2 that would provide for its continued operation through retirement at the end of the unit’s useful life.

With that, for purposes of only this I&M long-term economic evaluation process, assume…

- Rockport Unit 1 retrofit with SCR by December 31, 2017, as planned, and subsequently retrofit both Rockport units with Dry Flue Gas Desulfurization (“DFGD”) technology by December 31, 2025 (Unit 1), and December 31, 2028 (Unit 2); and
- add ash pond, effluent waste-water treatment, and other U.S. Environmental Protection Agency (“EPA”)-required equipment and investments at the Rockport Station by approximately the 2019-2021 timeframe.

Option #1B: Retrofit Rockport Unit 2 with SCR technology by December 31, 2019, and return the unit to the Lessor by the December 2022, Rockport Lease termination date.

With that, for purposes of only this I&M long-term economic evaluation process, assume...

- Rockport Unit 1 retrofit with SCR by December 31, 2017, as planned, and retrofit *only* Rockport Unit 1 with DFGD technology by December 31, 2025;
- replace I&M’s (85%) ownership/entitlement share of Rockport Unit 2 power and energy with *some combination of* similar-sized, new-build natural gas combined cycle units; natural gas simple-cycle combustion turbine units; aeroderivative units; combined heat and power generation; as well as new renewable (i.e., wind and solar) and incremental demand–side management resources by approximately January 1, 2023; and
- add ash pond, effluent waste-water treatment, and other U.S. EPA-required equipment and investments at the Rockport Station by approximately the 2019-2021 timeframe.

OPTION #2 - Do NOT install SCR on Rockport Unit 2

Option #2: Do not proceed with the Rockport Unit 2 SCR Project, but rather return the Unit to the Lessors by December 31, 2019, before the 2022 termination date in the Rockport Lease.

With that, for purposes of only this I&M long-term economic evaluation process, assume…

- incur payment, according to the terms of the Lease, of the Lease Termination Value effective as of that date;
- retrofit Rockport Unit 1 *only* with SCR by December 31, 2017, as planned, and, likewise, retrofit *only* Rockport Unit 1 with DFGD technology by December 31, 2025;
- replace I&M's (85%) entitlement share of Rockport Unit 2 power and energy with some combination of similar-sized, new-build CC units; CT units; AD units; CHP generation; as well as new renewable and incremental DSM resources by approximately January 1, 2020; and
- add ash pond, effluent waste-water treatment, and other U.S. EPA-required equipment and investments at the Rockport Station by approximately the 2019-2021 timeframe.

Q. WHAT IS THE SIGNIFICANCE OF THE DECEMBER 31, 2019 ROCKPORT 2 UNIT DISPOSITION DATE IDENTIFIED UNDER MODELED "OPTION #2"?

A. December 31, 2019, represents the required retrofit in-service date for the Rockport Unit 2 SCR as set forth within the terms of the Third Joint Modification to the Consent Decree ("Modified Consent Decree"). Based on the testimony of Company witness Hendricks, if the Rockport Unit 2 SCR Project is not installed by that date the unit cannot continue to operate. Hence, as indicated by Company witness Chodak, this condition would necessitate that the Rockport Lease would be terminated, with I&M and AEP Generating Company ("AEG") then obligated to pay the requisite Termination Value as set forth in the Lease. Such Termination Value as of December

2019 being estimated at $715.7 million[1] as provided to me by Mr. Chodak.

The specific terms of the Modified Consent Decree, as well as other existing and potential future environmental regulations, are discussed in detail in the testimony of Mr. Hendricks.

The Rockport Lease Agreement and its applicable terms and conditions, including end-of-term criteria, are discussed in the testimony of Mr. Chodak.

Q. WHY IS IT PRACTICAL TO CONSIDER, FOR PURPOSES OF THIS ECONOMIC ANALYSIS, A SCENARIO (OPTION #1B) WHERE ROCKPORT UNIT 2 WOULD ONLY BE AVAILABLE TO I&M FOR THREE YEARS AFTER THE INSTALLATION OF SCR TECHNOLOGY?

A. Given the current relative uncertainty of any end-of-lease-term disposition—one that may result in the exercise of an available Lease renewal option—the most reasonable, and least speculative, assumption for purposes of this analytical exercise would be to simply assume the unit would be returned to the Lessors at the Rockport Lease termination date. As explained further by Company witness Chodak this assumption does not preclude the Company from pursuing a Rockport Lease renewal afforded under the Rockport Lease.

In sum, Option #1B offers a "worst-case" view of an SCR retrofit "only" scenario, vis-à-vis Option #2 which would not proceed with the Rockport Unit 2 Retrofit Project. Option #1B is considered "worst case" because any Rockport Lease renewal would be established under terms that *must* result in more favorable long-term economics than the "Return at Termination

[1] This represents the <u>total</u> estimated Termination Value, with I&M's "85% (ownership and AEG purchase) share" being $608.4 million.

(December 2022)" option available to the Company under Option #1B as defined. Therefore, in spite of any practical considerations of potentially operating Rockport Unit 2 for a period of only three years after the installation of a major environmental retrofit, Option #1B essentially sets the minimum bound for purposes of determining the economic advantage to I&M's customers of proceeding with the Rockport Unit 2 SCR Project versus an approach that would *not* install the SCR and require the early termination of the Rockport Lease.

Q. WHAT WOULD BE THE ECONOMIC IMPLICATION OF INVESTING IN AN SCR BY DECEMBER 2019, WITH THE POSSIBILITY OF RETURNING THE UNIT TO THE LESSOR IN APPROXIMATELY 3 YEARS?

A. For Option #1A and #1B, the modeled cost-recovery period for the capital cost associated with the Rockport Unit 2 SCR Project to be completed in December 2019 was assumed to be 10 years (*i.e.*, by end-of-2029). This period is consistent with the allowable depreciation period under Ind. Code § 8-1-2-6.7, as described by Company witness Williamson.

However, recognizing in Option #1B that I&M's potential continued operation of Unit 2 could be limited to the end of the Rockport Lease term, a sensitivity analysis was also performed that would effectively proxy the costs associated with recovery of this retrofit investment by the potential end-of-2022 lease termination date (approximately 3-years). In short, on a cumulative present worth basis, there was only a very minor difference in the overall life-cycle costs of the 2019 Rockport Unit 2 SCR Project if all such investment costs were recovered over the shorter 3-year (versus 10-year) period. In fact, analogous to the typical favorable 'present value' economics of a 15-year versus 30-year home mortgage, the full life-cycle economics of the Rockport Unit 2 SCR Project (under Option #1B) would be slightly *improved* by $28 million if recovered over such a shorter (3-year) timeframe. Therefore, any such potential for accelerated Rockport Unit 2 SCR retrofit cost recovery recognition would not have any significant impact on the *long-term* modeled option results to be discussed.

Q. UNDER "OPTION #1A" YOU INDICATE THE LONG-TERM UNIT DISPOSITION EVALUATION PROCESS UNDERTAKEN HAS ASSUMED THE *FUTURE* RETROFIT OF DFGD TECHNOLOGY ON ROCKPORT UNITS 1 AND 2, AS WELL AS ADDITIONAL FUTURE ENVIRONMENTAL INVESTMENTS. DOES THE USE OF THIS ASSUMPTION MEAN THAT I&M HAS COMMITTED TO SUCH ADDITIONAL ROCKPORT INVESTMENT BEYOND THE ROCKPORT UNIT 2 SCR PROJECT?

A. No it does not. It simply offers—for current long-term modeling purposes only—a *potential* unit disposition line-of-sight. Under no circumstance does this option constitute a formal plan or recommendation by the Company for either Rockport unit beyond the nearer-term, Rockport Unit 2 SCR Project. Rather, it merely identifies the "down-stream" retrofit requirements/terms of the Modified Consent Decree as well as additional U.S. EPA requirements. Such EPA requirements include the final Coal Combustion Residuals ("CCR") rule addressing new and existing CCR landfills and surface impoundments, as well as the final Effluent Limitations Guidelines ("ELG") rule addressing certain wastewater discharges from power plants; each described by Company witness Hendricks.

Q. WOULD INSTALLATION OF SCR TECHNOLOGY ON ROCKPORT UNIT 2 BE A REASONABLE APPROACH, EVEN IF I&M ULTIMATELY DECIDED NOT TO INSTALL DFGD TECHNOLOGY ON THAT UNIT IN THE FUTURE?

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

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

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

Q. WHY WERE THE "(COAL-TO-GAS) REFUEL" AND "(CC) REPOWER" OPTIONS CITED IN THE MODIFIED CONSENT DECREE NOT MODELED AS OUT-YEAR ALTERNATIVES?

A. These options were not modeled as out-year alternatives largely due to the fact that, as addressed in the testimony of Company witness Pifer, the future retrofitting of the Rockport units with DFGD would be a more practical and reasonable option—based largely on known engineering and design factors—versus either re-fueling either of these steam units to burn natural gas, or undertaking a major repowering of the units as natural gas CC facilities. That said, any formal assessment of Rockport disposition options to be performed in the future could more fully examine those additional alternatives.

Q. WHAT ARE SOME OF THE OTHER UNDERLYING ASSUMPTIONS FOR I&M'S GENERATING FLEET?

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

- Rockport Unit 1 was assumed to be retrofitted with SCR by December 31, 2017, as planned (and authorized in Cause No. 44523), and DFGD technology by December 31, 2025.
- Tanners Creek Units 1-4 were retired on June 1, 2015 commensurate with I&M's compliance plan to meet the

requirements of EPA's Mercury and Air Toxics Standards ("MATS") rule.

- Continued operation of D.C. Cook Units 1 and 2 through at least the mid-to-late 2030's.[2]
- Continued operation of all pre-existing hydro and wind resources; the latter including a new 200 megawatt (MW) wind purchase agreement effective in 2015.
- Assume the 2016 in-service of the I&M solar pilot projects for approximately 15 MW (total) of solar resources.

Again, this is not a definitive commitment to pursue the installation of a Rockport Unit 1 (or Rockport Unit 2) DFGD. Rather, it simply serves as a going-in basis for the long-term modeling process for the "holistic" I&M resource optimization/disposition analysis. Any consideration of potential DFGD retrofits would be made under a separate, future proceeding.

Q. LIKEWISE WHAT WERE THE UNDERLYING ASSUMPTIONS ESTABLISHED FOR THE ROCKPORT UNIT 2 LEASE RENEWAL THAT WOULD BE APPLICABLE TO OPTION #1A?

A. As determined by I&M's management team, for purposes of establishing the economic evaluations for Option #1A, it was assumed that the respective I&M and AEG 50 percent leased shares of Rockport Unit 2 would continue beyond the potential 2022 lease termination date [redacted]

[2] This assumption is in-keeping with the D.C. Cook units' current 20-year Operating License Renewal through 2034 (Unit 1) and 2037 (Unit 2). However, no determination has been made by the Company to potentially pursue an additional license renewal beyond these dates.

[redacted]. As such—and as with many of the other long-term assumptions tied to "Option #1A"—it does not represent the Company's potential negotiating position regarding such lease renewal payments. Rather, it represents a reasonable modeling estimate for purposes of understanding the potential future cost implications for that option.

V. <u>CONSISTENCY WITH I&M'S 2015 IRP</u>

Q. ARE THE ROCKPORT UNIT 2 DISPOSITION OPTIONS DESCRIBED IN TABLE 1 CONSISTENT WITH I&M'S RECENTLY-FILED IRP?

A. Yes. As identified in TABLE 2 below, all three of the options identified on TABLE 1 are essentially the same as several of the "case" views found in the 2015 IRP:

TABLE 2

Rockport U2 CPCN Filing 'Option'	*corresponds directly with...*	I&M 2015 IRP Submittal 'Case'	*Description*
Option #1A	⟺	**"Steady State"**	*BOTH assume RU2 is fully-retrofitted (SCR & DFGD) and operated thru useful life*
Option #1B	⟺	**"Fleet Modification"**	*BOTH assume RU2 is retrofitted w/ SCR (only) then returned to Lessor @ 12/2022*
Option #2	⟺	**"Fleet Modification w/ No RU2 SCR"**	*BOTH assume RU2 is NOT retrofitted w/ SCR then returned to Lessor @ 12/2019*

[redacted]

Q. ARE THE COMPARATIVE RESULTS TO BE DISCUSSED IN THIS DIRECT TESTIMONY CONSISTENT WITH THE RESULTS SET FORTH IN I&M'S 2015 IRP?

A. Yes. As I will describe in further detail later, the relative results are very consistent with the "case-to-case" results offered in the IRP. While they do not much exactly match, those differences are minor and are explainable.

VI. <u>CAPACITY NEED</u>

Q. DOES I&M HAVE A CAPACITY NEED THAT WOULD BE INFLUENCED BY THIS ROCKPORT UNIT 2 DISPOSITION DECISION?

A. Yes. First, as explained in greater detail in Attachment SCW-1, I&M has an obligation to maintain a *minimum* PJM Installed Reserve Margin ("IRM") of 16.5 percent.[4] This IRM represents an obligation under PJM's capacity market construct—known as the Reliability Pricing Model ("RPM")—to ensure adequate future capacity resources are available to cover the Company's projected summer peak demand, as well as a reserve margin, needed to reasonably ensure reliability in the event of unforeseen supply interruptions and/or high peak demand events. As summarized on Attachment SCW-1, Table 1-4, *inclusive* of Rockport Unit 2, the projected I&M IRM for the next PJM RPM planning year, 2019/20,[5] is estimated at 20.56 percent. This IRM

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[4] Beginning with the current 2019/20 (June 1 through May 31) PJM RPM planning year; and assumed to remain constant in all future RPM planning years. In prior (2016/7 through 2018/19) planning/delivery years this requirement was slightly lower at 16.4 percent.

[5] As also discussed in Attachment SCW-1, I&M (as well as affiliates Appalachian Power Company and Kentucky Power Company) have continued to opt-out of the RPM "capacity auction" process by participating in the Fixed Resource Requirement ("FRR") "self-planning" construct afforded under the RPM. Under the RPM framework that establishes a 3-year forward commitment, this FRR obligation has now been established through at least the 2019/20 RPM planning year.

level would result in a capacity "length"—*i.e.*, capacity levels above the minimum 16.5 percent PJM criterion—of a reasonable 159 MW.

Therefore, any unit disposition decision that would implement an alternative of retiring I&M's 1,105 MW ownership and purchase entitlement share of Rockport Unit 2 [6] would result in an immediate and significant need to replace nearly all of that capacity to ensure the achievement of this PJM IRM criterion. This explains why the "Option #1B" and "Option #2" alternatives previously identified in TABLE 1 would necessitate a near-concurrent replacement of the unit with significant capacity replacements.

Q. IS THE UNDERLYING I&M LOAD AND PEAK DEMAND FORECAST AND ULTIMATE CAPACITY "NEED" CONSIDERED AS PART OF THIS ROCKPORT UNIT 2 DISPOSITION ANALYSIS ALSO CONSISTENT WITH THAT WHICH WAS REPRESENTED IN THE COMPANY'S NOVEMBER, 2015 IRP?

A. Yes. There were no changes to the long-term load and peak demand forecast, as well as assumptions around available capacity resources, from the forecast utilized in I&M's 2015 IRP. I am aware that I&M was recently notified that some contracts for wholesale supply may end in 2020. While the load associated with these contracts was included in the long-term load forecast, a potential change in the disposition of the load contracts, should they leave the system, would not alter the conclusion in this testimony. The potential loss of this approximately 300 MW of internal load would not diminish the Company's future need for Rockport Unit 2 or, alternatively,

[6] 650 MW (50%) I&M ownership share of the 1300-MW unit; plus I&M's 455 MW (70%) purchase entitlement from affiliate AEG's 50% ownership share of the unit.

some level of replacement resources that reasonably approaches that unit's level of capacity should it be returned to the Lessor.

VII. ECONOMIC MODELING PROCESS

Q. HOW WERE THE ROCKPORT UNIT 2 DISPOSITION ALTERNATIVES ANALYZED?

A. The Company utilized a proprietary long-term resource optimization tool known as Plexos® (also referred to as "Plexos® LT Plan") to perform this evaluation. The economic evaluations were performed from the perspective of a "stand-alone" I&M. This means there were no assumed capacity and energy costs or credits flowing to/from affiliate AEP operating companies by virtue of the fact that the long-standing AEP Interconnection Agreement ("AEP Pool") has now been terminated and replaced with the FERC-authorized Power Coordination Agreement ("PCA") effective January 1, 2014. Under the terms of the PCA, I&M, as well as the other AEP-affiliate operating company participants in the PCA, "…will be individually responsible for its own capacity planning."[7]

Further, these resource optimization evaluations were performed over an extended (30-year) modeled period (2016 through 2045) in the Plexos® tool so as to roughly emulate the potential economic life-cycle of the respective asset alternatives offered in TABLE 1; as well as in recognition of the various future impacts on I&M's overall resource planning needs. As will be described in more detail, the alternative-specific 'Net Utility Costs' were

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

then discounted to current, "(January) 2016" dollars and, as such, reflected on a cumulative present worth ("CPW") basis.

It is also critical to understand that the framework for these evaluations was focused not on the *absolute* CPW results for I&M, but rather the *comparative* view of the alternative options' results. In other words, the objective of this exercise was to identify the relative least-cost alternative among the three primary options identified in TABLE 1. With that, the results from Plexos® offer a view of these relative optimization economics over that full, 30-year planning horizon and thereby do not in any way constitute an isolated, single "test-year" cost-of-service view.

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

A. Plexos® is a proprietary software tool under license to AEPSC from Energy Exemplar LLC, a power and gas industry software and data-services provider. As indicated, the Plexos® LT Plan version of the application is a long-term resource optimization model that offers multiple objective functions, including determination of alternative planning solutions that offer the lowest utility cost. In this case, it is intended to determine a proxy for the lowest "G(eneration)" (net) cost-of-service.[8] The model uses linear programing ("LP") optimization techniques to find the optimal portfolio of future capacity and energy resources, including demand-side additions, that serve to minimize the CPW of a planning entity's production-related fixed and variable costs over a long-

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

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

This latter ability is important given that the Modified Consent Decree also places a Rockport (total) station-specific "cap" on SO_2 emissions of 28,000 tons per year in 2016-2017; 26,000 tons per year in 2018-2019; 22,000 tons per year in 2020-2025; 18,000 tons per year in 2026-2028; and 10,000 tons per year in 2029 and thereafter.[9] These station-specific SO_2 requirements are over-and-above the pre-existing AEP performance thresholds around SO_2 and NO_X emissions as set forth in the original NSR Consent Decree. As further described by Company witness Hendricks, the retrofit of SCR on Rockport Unit 2 will contribute to the attainment of that Consent Decree requirement.

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

A. Yes. Plexos® was utilized as the applicable modeling tool for determining the relative economics of the Rockport Unit 1 SCR Project in Cause No. 44523. It was also utilized as the basis for all proforma analyses in I&M's most recent IRP submitted on November 2, 2015. Specifically, it served as the basis for the establishment of the resource planning included under Section 8-

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

"Selection of the Resource Plan"—as required under 170 IAC 4-7-8.[10] Additionally, Plexos® was utilized as part of the Company's most recent biannual Fuel Adjustment Clause ("FAC") filings.[11] It was also utilized as part of I&M's most recent Environmental Compliance Cost Rider ("ECCR") filings.[12] Likewise, Plexos® was utilized to establish I&M's most recent Power Supply Cost Recovery plan for its Michigan retail jurisdiction.[13] Further, Plexos® has recently been utilized by other AEP operating companies to support both long-term resource planning options as well as shorter-term fuel factor applications before Commissions in the states of Arkansas, Kentucky, Oklahoma, Texas, Virginia, and West Virginia.

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

A. First, the Plexos® model seeks to emulate the PJM energy construct in which all available generation is offered into, and is compensated by, the PJM energy market; while all Load Serving Entities, such as I&M, are price-takers from that market. Both of these time-based value-sets are predicated on the future, fundamentals-based price of energy which will be described later in this testimony. As a vertically-integrated utility, the subsequent 'netting' of those (PJM) "(Generation) Market Revenues" and "Load Costs" profiles are

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[10] *See* Section 5 of that submittal for a description of how Plexos® LT Plan was utilized in I&M's 2015 IRP.
[11] *See* IURC Cause Nos. 38702-FAC73, 38702-FAC74 and 38702-FAC75 and 38702-FAC76.
[12] *See* IURC Cause Nos. 43992-ECCR 4 and 43992-ECCR 5.
[13] *See* MPSC Case No. U-17919

then appended to the anticipated production cost of I&M's native generation, to create a full picture of I&M's projected future net utility (generation) costs. The model determines such generation-related costs as follows:

Cost of Generation…

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

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

Plus: Variable Costs of Energy Purchases

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

Plus: Fixed O&M of Capacity Additions

Plus: Fixed Cost of Capacity Purchases

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

= **Total Generation Costs**

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

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

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

These life cycle costs through the 2045 modeled optimization period, along with applicable end-effects[14], are then “present-valued” using a proxy of the estimated I&M-weighted average cost of capital, to create a CPW of Net Utility (Generation) Costs.

Q. SPECIFICALLY, HOW DID THE PLEXOS® MODEL PERFORM THE ROCKPORT UNIT 2 DISPOSITION ANALYSES SUMMARIZED ON TABLE 1?

A. For “Option #1A”, the model incorporated the Rockport Unit 2 SCR Project alternative—and timing thereof—as described earlier in TABLE 1. Specifically, Rockport Unit 2 was assumed to be “fully-retrofitted” in the future, first with DSI and associated equipment (for MATS compliance), then SCR

[14] Recognizing the varying life cycle periods among alternatives evaluated, an “end-effects” determination was made that is representative of the present value of any on-going cost streams beyond the model’s 2045 optimization period.

technology by December 31, 2019; and finally with subsequent anticipated environmental-related retrofits thereafter—including DFGD technology—by December 31, 2028. The Rockport Lease was assumed to be renewed for Unit 2, while the remaining I&M generating units were assumed to follow the "base" disposition path assumptions as previously discussed.

For "Option #1B", the model assumed Rockport Unit 2 would be returned to the unit's Lessors at the lease termination date of December, 2022, with the installation of the SCR in 2019—consistent with Option #1A—but, naturally then, *without* the installation of a DFGD in 2028. Upon the unit's assumed return to the Lessors, the model further assumed that nearly all of the significant displaced Rockport Unit 2 capacity and energy would require concurrent replacement resources.

Finally, for "Option" #2, the model assumed Rockport Unit 2 would be returned early to the Lessors—by December 2019—*without* the installation of an SCR in 2019, and a DFGD in 2028. This modeled view also incorporated the required concurrent resource replacement upon the unit's return to the Lessors.

For each view (Options #1B and #2) requiring nearer-term replacement resources, the model was given the ability to select the specific type of capacity resource required to replace Rockport Unit 2 by way of Plexos®-LT Plan's resource optimization logic. In that regard, given the assumption of the impracticality of a coal solution due to proposed CO_2 emissions regulations applicable to new fossil-fired generating resources, a new coal-fired generating build was not considered.[15] Likewise, given the financial impracticability of new nuclear capacity with estimates costs exceeding \$6,000/kW, a new nuclear unit was also not considered.[16] With that, the model had the ability to choose between some combination of natural-gas fired combined cycle ("CC"), combustion turbine ("CT"), aeroderivative ("AD"), combined heat and power ("CHP"), as well as renewable and incremental demand-side management ("DSM") resources; all consistent with the resource replacement options utilized in the 2015 IRP.[17]

From there, the model was set up with the necessary input parameters, such as capital cost to retrofit or to replace with alternative resources, the attendant fuel cost and generator performance parameter data, modifications to variable and fixed O&M, etc. Based on these inputs, beginning in the year 2020—the initial full year of Rockport Unit 2 being retrofitted with SCR—the model was then capable of recognizing any relative change in the overall I&M generation profile for each of the three Rockport Unit 2 disposition options identified in TABLE 1. Additionally, the capacity resource planning aspect of the tool recognized the megawatt contribution of these alternative solutions when determining capacity needs for I&M *beyond*

[15] New EPA regulations pertaining to Section "111(b)" of the Clean Air Act require new coal-fired generating facilities to emit no more than 1,400 lb/Mwh of CO_2; levels essentially unachievable without some form of costly carbon capture and sequestration technology.
[16] For example, a nuclear unit @ 1,100 MW –roughly comparable to the size of either of I&M's D.C. Cook nuclear units; or the size of I&M's share of Rockport 2 being replaced— would cost \$6.6 Billion (\$6,000/kW x 1,100 MW x 1,000 kW/MW = \$6,600,000,000).
[17] Specifically, additional DSM over-and-above the levels embedded in the Company's load & peak demand forecast (as summarized on Attachment SCW-1, Table 1-3); as well as additional I&M renewable resources over-and-above those currently identified (or footnoted) on Attachment SCW-1, Table 1-2.

2020, as it modeled throughout the long-term optimization planning horizon (*i.e.*, through 2045).

Q. PLEASE IDENTIFY SOME OF THE INPUT PARAMETERS FOR THESE ROCKPORT UNIT 2 DISPOSITION ANALYSES?

A. Two of the major underpinnings in this process are long-term forecasts of I&M's energy requirements and peak demand, as well as the price of various generation-related commodities, including energy, capacity, coal, natural gas, and CO_2/carbon. Both forecasts were created internally within AEPSC. The load forecast, including I&M load and peak demand summaries discussed in Attachment SCW-1, represents the projection created by the AEP Economic Forecasting organization in June 2015 that led up to, and was utilized in, the 2015 IRP. Attachment SCW-2 offers the long-term commodity pricing forecast established by the AEP Fundamental Analysis group in that same June/July 2015 timeframe. These respective organizations have had years of experience forecasting I&M and AEP system-wide demand/energy requirements and fundamental pricing for both internal operational and regulatory purposes.

Other critical input parameters include the installed cost of the required Rockport Unit 2 SCR Project, the cost to build/buy replacement capacity (e.g. CC, CTs, ADs, CHP, renewable [wind, solar], or incremental DSM), as well as the attendant on-going operating costs and performance parameters associated with those unique options, where applicable. Much of this information is summarized on Attachment SCW-3. The critical build-cost data was largely provided by Company witness Pifer and the AEP Generation organization of which he is a part.

Q. PLEASE PROVIDE AN ADDITIONAL OVERVIEW OF THE "RETURN AND REPLACE" OPTIONS (OPTION #1B AND OPTION #2).

A. The Plexos® modeling required to reasonably proxy this option as it pertains to the installation of nearer-term baseload/intermediate duty-cycle capability was based on resource "blocks" equivalent to *one-half* of a Mitsubishi 501 GAC 2x2x1 combustion turbine/heat recovery steam generator (HRSG)/steam turbine design[18] natural gas CC that would have a nominal capability of approximately 780 MWn[19]. This was done as an input process to the Plexos® modeling so as to allow for reasonably equivalent "block-sizes" amongst the available resource options. Therefore, each CC equivalent block-size the model could select was equal to 390 MWn. This type/construct of CC was screened as being the 'best-in-class' from multiple potential CC designs.

The chosen proxies for potential peaking duty-cycle capability were based on both a simple-cycle General Electric ("GE") 2x '7FA' (large-frame) *and* GE 2x '7EA.03' (small frame) natural gas CT block-sizes the model could select having a nominal capability of approximately 431 and 189 MWn, respectively.[20] Additionally, the model could choose 2x GE LM6000 AD units

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

[19] This Mitsubishi design CC would provide, via evaporator cooling, additional unit generating capability—albeit at some thermal efficiency/heat rate penalty—to 870 MW.

[20] Each GE 7FA turbine is nominally rated @ 215.5 megawatts ("MWn"). Each GE 7EA.03 turbine is nominally rated @ 89.5 MWn. A minimum GE 7FA and 7EA.03 SC block size was assumed to be 2 turbines; or ~431 MWn and 189 MWn, respectively.

having a nominal capability of approximately 87 MWn[21] per block. Lastly, it could also select scaled CHP-cogeneration units[22]. The GE SC-CTs, GE-ADs as well as CHP generating resources were all screened as the best-in-class from multiple potential "peaking" duty-cycle resource options.

Q. WHAT ESTIMATED COSTS FOR OPTION #1A, OPTION #1B, AND OPTION #2 WERE UTILIZED IN THE ECONOMIC EVALUATIONS?

A. The following **TABLE 3** offers a summary of the installed cost estimates modeled:

[21] Each GE LM6000 AD turbine is nominally rate @ approximately 43.5 MWn, also with a minimum block size of 2 turbines; or ~87MWn.
[22] The CHP-cogeneration tranche size is based on a reduced-scaled LM6000 turbine, coupled with a full steam host, offering a generation output of approximately 15 MWn.

TABLE 3

Estimated Rockport Unit 2 Disposition Alternatives
Major Capital Expenditures (excl. AFUDC)
Utilized in Plexos® Modeling
In Addition to Wind, Solar and (Incremental) DSM

Row	Description	Unit Capacity MW		(a) Direct (EPC) & Indirect Costs: Millions ('As-Spent' $)	(b) Direct (EPC) & Indirect Costs: $/kW Installed (2015 $)	(c) I&M/AEG Prod. Capital Overhead: Millions ('As-Spent' $)	(d) TOTAL COST (Excluding AFUDC): Millions ('As-Spent' $)	(e) TOTAL COST (Excluding AFUDC): $/kW Installed (2015 $)
(1)		*Unit Capacity*		Millions	$/kW Installed	Millions	Millions	$/kW Installed
(2)		*MW*		*('As-Spent' $)*	*(2015 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2015 $)*
(3)	**Option #1A:**							
(4)	**(Unit 2 RETROFIT Option)**							
(5)	TOTAL Project Costs							
(6)	**Rockport U2 SCR (12/2019 in-Svc) (Option #1A and Option #1B)**	*1,336*	(A)	**257**	**$177**	**17**	**274**	**$189**
(7)	*Plus: Potential Subsequent Major U1 & U2 Investments included in Modeling:*							
(8)	*RK U1 DFGD & Assoc. (12/2025 In-Svc) (ALL Options)*	*1,333*	(B)	*1,217*	*$729*	*82*	*1,299*	*$778*
(9)	*RK U2 DFGD & Assoc. (12/2028 In-Svc) (Option #1A only)*	*1,318*	(B)	*1,306*	*$734*	*88*	*1,394*	*$784*
(10)	*RK U1 & U2 "CCR/ELG"-related,*							
(11)	*Total Plant (thru 2021) (ALL Options)*	*2,687*	(A)	*179*	*$60*	*12*	*191*	*$64*
(12)	*TOTAL ALL Major Rockport Environmental Projects (U1&2) (Opt #1A only*	*2,651*	(B)	*2,958*	*$882*	*200*	*3,158*	*$941*
(13)	***I&M Ownership Share @ 50%***							
(14)	**Rockport U2 SCR (12/2019 in-Svc) (Option #1A and Option #1B)**	*668*		**128**	**$177**	**9**	**137**	**$189**
(15)	***I&M 70% Purchased Power Portion of AEG's 50% Ownership Share (C)***							
(16)	**Rockport U2 SCR (12/2019 in-Svc) (Option #1A and Option #1B)**	*468*		**90**	**$177**	**6**	**96**	**$189**
(17)		*Unit Capacity*		Millions	$/kW Installed	Millions	Millions	$/kW Installed
(18)		*MW*		*('As-Spent' $)*	*(2015 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2015 $)*
(19)	**Option #2 (and Option #1B):**							
(20)	**(Unit 2 CAPACITY REPLACEMENT Options)** (D)							
(21)	**New-Build CC...** 1/2023 In-Svc (**Option #1B**)	*1x390MWn (435 w/evp clg) "block"*		547	$1,087	37	584	$1,160
(22)	" " " ... 1/2020 In-Svc (**Option #2**)	"		507	$1,087	34	541	$1,160
	AND (IN COMBINATION WITH) / OR ...							
(23)	**(2)X New-Build CT (7FA)...** 1/2023 In-Svc (**Option #1B**)	*2x215.5 = 431 per block*		384	$753	26	410	$804
(24)	" " " " ... 1/2020 In-Svc (**Option #2**)	"		356	$753	24	380	$804
	OR							
(25)	**(2)X New-Build CT (7EA.03)...** 1/2023 In-Svc (**Option #1B**)	*2x89.5 = 179 per block*		212	$1,001	14	227	$1,068
(26)	" " " " ... 1/2020 In-Svc (**Option #2**)	"		197	$1,001	13	210	$1,068
	OR							
(27)	**(2)X New-Build AD (LM6000)...** 1/2023 In-Svc (**Option #1B**)	*2x43.5 = 87 per block*		114	$1,107	8	122	$1,182
(28)	" " " " ... 1/2020 In-Svc (**Option #2**)	"		106	$1,107	7	113	$1,182
	OR							
(29)	**CHP-Cogen(LM6000 w/stm hst)...** 1/2023 In-Svc(**Option #1B**)	*15*	(E	32	$1,773	2	34	$1,893
(30)	" " " " ... 1/2020 In-Svc (**Option #2**)	"		29	$1,773	2	31	$1,893

(A) Rockport U1 & U2 capacity rating post-planned LP Turbine (36 MW each) uprates (2017 & 2019)
(B) Rockport U1 & U2 capacity rating post-DFGD retrofits (<18 MW> each) derates (2025 & 2028)
(C) I&M would ALSO incur its 70% share of fixed costs associated with AEG's like-50% share of the project (or, 35% of the 'Total Project')
under the terms of the affiilate AEP Generating Company (AEG) Unit Power Agreement with I&M.
(D) AEP Projects cost estimates used for modeling purposes.
(E) Assumes a full-utilization steam host (thermal efficiency @ ~4,858 Heat Rate)

The costs reflect the 50 percent ($137 million) I&M ownership share of the capital expenditure associated with the Option #1A and #1B Rockport Unit 2 SCR Project. I&M-affiliate AEG would be responsible for the other 50 percent share of the required capital expenditure. In recognition of this, however, these I&M-Rockport Unit 2 disposition analyses *also* considered 70 percent of the costs of the AEG ownership portion of this retrofit solution by virtue of I&M's obligation under the AEG UPA. Stated another way, the Option #1A and #1B analyses effectively reflected 85 percent (1,105 MW) of the capacity (and energy output), as well as the respective attendant costs, associated with the approximate 1,300 MW Rockport Unit 2 SCR Project estimate.[23]

Note also that these costs are exclusive of allowance for funds used during construction ("AFUDC"). As it pertains to the Option #1A and #1B Rockport Unit 2 SCR Project estimate, the total project cost inclusive of production capital overheads as well as AFUDC was modeled at approximately $295 million (with I&M's 50% ownership share being approximately $147 million). Conservatively, this calculated AFUDC proxy of nearly $21 million (I&M's ownership share being approximately $10 million) was incorporated for comparative modeling purposes only and is, obviously, before consideration of any potential construction work in progress ("CWIP") recovery treatment as discussed in Company witness Williamson's testimony

[23] Represents I&M's 50% ownership share, plus, 70% of AEG's 50% ownership share, or 85%.

that would serve to eliminate all or a portion of any such project-related AFUDC.[24]

Q. EARLIER YOU DISCUSSED "DOWN-STREAM" COSTS ASSOCIATED WITH ENVIRONMENTAL INVESTMENTS BEYOND THE CURRENT ROCKPORT UNIT 2 SCR PROJECT. PLEASE BRIEFLY DESCRIBE THE OPTION #1A TOTAL UNIT 2 COST PROJECTIONS INCORPORATED INTO YOUR MODELING.

A. As summarized on TABLE 3, the Plexos® modeling for Option #1A incorporated approximately $1,347 million of additional estimated I&M capital costs for various future Rockport Unit 2 projects beyond this Unit 2 SCR Project. Specifically, this figure represents I&M's 85 percent ownership *and* (AEG) purchased power share of the combined investment in future Unit 2 DFGD and associated equipment (total $1,394 million), and "CCR/ELG-related" ($191 million, total plant) capital costs identified on TABLE 3.[25]

Q. HOW WERE ROCKPORT UNIT 2 CAPACITY *REPLACEMENT* ALTERNATIVES CONSIDERED IN EITHER OPTION #1B OR OPTION #2?

A. The Plexos® modeling was based on the assumption that any and all incremental capacity and energy requirements to achieve I&M's projected native peak demand and load requirements, in recognition of a Rockport Unit 2 return to Lessors by December 2022 (Option #1B), or by December 31, 2019 (Option #2), would be wholly met via CC, CT, AD, CHP, renewable and

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[24] $295 million total (100%) project cost - $274 million total cost (including production capital overhead, but excluding AFUDC – see TABLE 3)

[25] ($1,394 million + $191 million) x 85% = $1,347 million (including capital overheads, excluding AFUDC).

incremental DSM replacement capacity and energy contemporaneously with those respective dates.

Q. IN DEVELOPING THE COMPANY'S FUTURE RESOURCE ALTERNATIVES AS PART OF OPTIONS #1B AND #2, DID THE COMPANY EVALUATE DEMAND-SIDE/ENERGY EFFICIENCY AND DEMAND RESPONSE RESOURCES?

A. Yes. As described and detailed in Attachment SCW-1, Section H, DSM in the form of Energy Efficiency (EE) and Demand Response (DR) initiatives have been incorporated into the Company's resource planning process, initially, as part of its underlying load forecast. These forecasted levels of EE reductions incorporated into all of I&M's long-term resource modeling are significant. Note on Table 1-3 of Attachment SCW-1, that the Company is projected to realize permanent peak demand reductions from EE alone of 64 MW over the balance of this decade. Additionally, the Company is expected to add further peak demand reductions via 'demand response' activity of 298 MW. With that, the Company's *total* demand-side peak reduction capability is already projected to be 363 MW by 2020. This amount is equal to approximately 9.8 percent of I&M's forecasted retail peak demand.[26] Given the more limited ability of DSM to add extremely large tranches of resources to I&M's overall portfolio—over-and-above what is already contemplated in the underlying load and peak demand forecast—as a practical matter such amounts must be considered minimal in the context of the approximate 1,100 MW of I&M's share of Rockport Unit 2 capacity that would be required to be replaced.

[26] Based on projected 2020 I&M (retail only) peak demand *before* DSM of 3,702 MW.

That said—consistent with the underlying modeling for its 2015 IRP--I&M's Plexos® long-term resource optimization modeling did consider such *incremental* contributions of EE resources as part of this Rockport Unit 2 evaluation process. The model was given the ability to select from eight (8) potential incremental DSM-EE measure "bundles" including: Residential Heating/Cooling; Residential Thermal Shell; Residential Lighting; Residential Water Heating; Residential Appliances; Commercial Heating/Cooling; Commercial Lighting; and Commercial Office Equipment.

Q. COULD ADDITIONAL RENEWABLE RESOURCES—OVER-AND-ABOVE I&M'S 450 MW OF WIND RESOURCES AND 15 MW OF SOLAR RESOURCES—BE CONSIDERED A VIABLE DISPOSITION ALTERNATIVE FOR ROCKPORT UNIT 2 REPLACEMENT CAPACITY IN OPTIONS #1B AND #2?

A. Yes, but as with incremental DSM, only to a limited degree. Given the intermittent nature of, for instance, wind resources, only a small percentage of the "nameplate" capacity rating of wind is currently being recognized by PJM for reliability/capacity resource adequacy planning purposes. In fact, PJM initially recognizes or "counts" only 13 percent of a wind resource's nameplate (MW) rating for such capacity planning purposes.

Further, as described more fully in Attachment SCW-1, beginning with the 2020/21 PJM Planning Year a new FERC-authorized RPM tariff referred to as the "Capacity Performance" construct will be in full effect. At that point all intermittent resources, including wind, are anticipated to experience a further reduction in the level of capacity resources that may be applied when establishing PJM capacity position/need. For purposes of future capacity resource commitments under that Capacity Performance construct, the Company assumed that the amount of a wind resource's nameplate (capacity) rating that will be applicable would be zero beginning with that 2020/21 PJM-RPM planning period. Therefore, wind resources, which can be a beneficial source of <u>energy</u> by adding diversity to a generating portfolio, cannot serve as a viable *capacity* replacement alternative in this instance. In any event, irrespective of the anticipated new 'Capacity Performance' limitations, even under the *current* (13 percent of nameplate) PJM framework—which is <u>not</u> subject to conjecture—wind resources would be able to contribute only limited capacity resources to meet the reserve margin criterion. For example, to meet even just <u>*one-tenth*</u> of the Company's capacity obligation in lieu of Rockport Unit 2 post-2020, 850 MW (nameplate) of additional wind resources would be required over-and-above the 450 MW of wind resources the Company already currently possesses.[27] Under the emerging *Capacity Performance* approach, wind has been assumed not to "count" for purposes of I&M achieving its future capacity resource requirement.

The implication is similar for solar resources. That is, currently PJM initially counts only 38 percent of a solar resources nameplate MW rating when establishing capacity contribution to meet load/demand and reserve margin obligations. Unlike wind resources, however, for purposes of future resource commitments under that Capacity Performance construct, the

[27] 1,105 MW x 1/10 = 110.5 MW / 0.13 (PJM [nameplate] assumed installed capacity criterion limitation re wind resources) = 850 MW

Company assumed that the amount of a solar resource's nameplate rating that will be applicable for capacity planning purposes would remain at that 38 percent level beginning with that 2020/21 PJM-RPM planning period.[28] So, again, to meet even just *one-tenth* of the Company's capacity obligation in lieu of Rockport Unit 2, over 290 MW (nameplate) of additional solar resources would be required post-2020.[29]

However, to be non-discriminatory as to the overall make-up of the available suite of resources to potentially replace Rockport Unit 2, the Company—as it did with incremental DSM—considered the prospect of renewable resources; namely, wind and large/community-scale solar, as potential capacity (and energy) resource options from which the Plexos® long-term optimization modeling could select over the long-term optimization study period. As with incremental DSM, however, this would recognize that, at best, such (incremental) wind or solar resources would likely be able to contribute only a small fraction of the *capacity* contribution lost by the retirement of Rockport Unit 2.

Q. ARE THESE WIND AND SOLAR CAPACITY RESOURCE CRITERIA CONSISTENT WITH THOSE UTILIZED IN I&M'S 2015 IRP?

A. Yes. The 2015 IRP also assumed the 'post-2020' level of wind and solar that could 'count' in the achievement of its PJM minimum reserve margin requirement would be set at 0 percent and 38 percent of nameplate, respectively.

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[28] This was done in recognition of the fact the load shape of a solar resource is typically more coincident to an overall PJM summer peak condition/hour than that of a wind resource.

[29] 1,105 MW x 1/10 = 110.5 MW / 0.38 (PJM [nameplate] installed capacity criterion limitation re solar resources) = 291 MW

Q. IS PROJECTED NATURAL GAS PRICING A DRIVER FOR SUCH ANALYTICAL PROCESSES?

A. Yes, it typically is. In the electric utility industry, the natural gas-fired units often serve as the marginal cost, or "price-setting" units based on their relative higher position in a typical regional dispatch stack (relative to lower variable cost hydro, nuclear and coal-fired units). In PJM, that is most typically the case during "on-peak" hours.[30] Therefore, the price of natural gas will not only determine where gas-fueled units may fall in any regional dispatch stack, it will then largely determine the Locational Marginal Price ("LMP") in which energy may clear in any market-based system such as PJM.

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

Conversely, the lower the gas price, the lower these CC units may fall in PJM's market-based dispatch/supply stack, thereby setting a lower clearing price for a greater number of hours/sub-hours. Under this latter outcome, coal units could potentially be called upon to generate less energy at a lower available spread.

Q. PLEASE PROVIDE AN OVERVIEW OF THE FORECASTED FUNDAMENTAL COMMODITY PRICING, INCLUDING NATURAL GAS,

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

THAT WERE USED IN THE ROCKPORT UNIT 2 DISPOSITION ANALYSES?

A. As shown in **TABLE 4** below, an array of five (5) unique, long-term commodity pricing scenarios were utilized in the Rockport Unit 2 disposition analyses, consisting of a "base" view; two "price banding" sensitivity views; and two "CO_2/carbon" views:

TABLE 4

'BASE' Forecast … *reflecting:*

- Recognition of relatively lower fuel price trending due to proliferation of shale gas, increasing natural gas price elasticity; as well as capturing a likely implementation profile of environmental regulation including CSAPR, MATS Rule and potential CO_2 mitigation via a ~$15/tonne[31] "carbon tax" (beginning in 2022).

Commodity Price Banding Scenarios…

2. "Higher Band"…*same as the BASE case except:*

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

3. "Lower Band" … *same as the BASE case except:*

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

CO_2 Pricing Scenarios…

4. "No Carbon" Price… *same as the BASE case except:*

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

5. "High Carbon" Price… *same as the BASE case except:*

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

[31] The unit of measure representing a "metric" ton of CO_2 equal to 1,000 kilograms or 2,204 pounds and represented in "real" (2014) dollars.

The “BASE” Forecast” view reflects the full suite of long-term projection of commodity prices—inclusive of natural gas prices—established by the AEP Fundamental Analysis group that were used in this analysis. This forecast was internally published in the mid-2015 timeframe. Selected commodity pricing projections from that suite are reflected in Attachment SCW-2. This BASE Forecast view focused significantly on emerging natural gas pricing dynamics and considered evolving information that would support natural gas supply increases tied to the projected emergence of additional, significant levels of domestic shale gas at very competitive extraction costs.

This long-term view also assumes and embeds a “CO_2 pricing” impact as a result of potential carbon regulation such as the regulation of CO_2 emissions from *existing* fossil-fueled generating sources as recently set forth by the U.S EPA under Section 111(d) of the Clean Air Act via its Clean Power Plan (“CPP”). In conjunction with the final CPP ultimately submitted in August of 2015, the timing of a carbon pricing proxy in these long-term fundamental pricing forecasts was likewise assumed to be the year 2022.[32]

Q. ARE THE LONG-TERM COMMODITY PRICE FORECASTS USED IN THIS ROCKPORT UNIT 2 SCR PROJECT ANALYSIS—SUMMARIZED ON TABLE 4—CONSISTENT WITH THE PRICING FORECASTS USED IN I&M’S RECENT (NOVEMBER 2015) IRP SUBMITTAL?

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[32] The Company and AEP’s assumption/position around the prospect of a CO_2 carbon tax has been consistently assuming such a value/price in the AEP Fundamental Analysis group’s “base” pricing projections since approximately the ‘2008’ vintage forecasts; through the 2015 vintage forecast. The initial *timing* of such CO_2/carbon pricing in those earlier forecasts started around the year 2015, and has gradually migrated to the currently-assumed 2022 effective date.

A. Yes, the forecasted pricing used in I&M's 2015 IRP is the same for all scenarios represented on TABLE 4.

VIII. <u>EVALUATION OF MODELING RESULTS</u>

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

A. Attachment SCW-4-1 and Attachment SCW-4-2 offer tabular summarizations and comparison of the modeling results for the three primary disposition options for Rockport Unit 2 that were outlined in TABLE 1. Attachments SCW-4A through 4E offer a broader view of the results for the BASE (pricing) Forecast and each of the four alternative commodity pricing scenarios defined in TABLE 4 above.

Again, these modeling results represent <u>relative</u> cost analyses, meaning each are compared to one another in the determination of the "least-cost" alternative outcome. Given that, Attachment SCW-4-1 and Attachment SCW-4-2 reflect the relative costs of the alternative options that would call for the 'return and replacement' of Rockport Unit 2 (Options #1B and #2) when *compared to* a reference alternative. For purpose of these economic assessments, the reference alternatives were established as being each of the "Install SCR" alternatives—Option #1A and Option #1B.

Attachment SCW-4-1 offers a comparison versus *Option #1A* as the reference view. Here the analysis is assessing the relative economics of not only the Rockport Unit 2 SCR Project, but also the eventual prospect of further retrofits on Rockport Unit 2; all versus options that would return the unit to the Lessors in the relative near-term and replacing with alternative resources.

Attachment SCW-4-2 offers a different perspective by offering a similar relative comparison, but with *Option #1B* as the reference view. This comparison rather focuses on the relative economics of the Rockport Unit 2 SCR Project nearly *exclusively*—specifically, for Option #2 vs. Option #1B. The reason for this is that subsequent to the year 2022, there are essentially little-to-no cost differences between those two alternatives as both are setting forth largely the same Rockport Unit 2 “replacement” resource profile.

Q. PLEASE SUMMARIZE THE RESULTS IN ATTACHMENTS SCW-4-1 AND SCW-4-2.

A. <u>Attachment SCW-4-1</u>:

This attachment offers an all-encompassing view of the relative modeling results for the evaluations performed in Plexos®. It is segregated into the five sets of future commodity pricing scenarios—displayed vertically—that were identified in TABLE 4, all vis-à-vis Option #1A. Supporting information for each of those option-specific pricing scenario views is offered individually as part of supporting Attachments SCW-4A through 4E.

Focusing first on the relative disposition results under the “BASE Forecast” commodity pricing scenario, it suggests that the Rockport alternative “SCR Retrofit Rockport 2 by 12/2019; then Return and Replace with various resource alternatives (CC, CTs, AD, CHP, renewables, and incremental DSM) by 1/2023” (Option #1B) would be <u>more costly than Option</u>

#1A by $84 million over the long-term study period. Moving down the attachment to assess the "sensitivity" pricing scenarios, Option #1B is more costly by amounts ranging from $349 million for the "Higher Band" price scenario; to being $131 million *less* costly under the "Lower Band" price scenario.

Focusing next on the other Rockport Unit 2 disposition alternative modeled, the "*No* SCR Retrofit, but Return and Replace with various resource alternatives by 1/2020 (Option #2) would be more costly than Option #1A by $322 million under the "BASE" pricing scenario. It also indicates that Option #2 is more costly by amounts ranging from $621 million to $99 million; again under the same respective long-term "Higher Band" and "Lower Band" pricing scenarios.

Attachment SCW-4-2:

Now considering these results from the perspective of Option #1B, under BASE commodity pricing scenario, it indicates that Option #2 would be more costly than Option #1B by $239 million over the long-term study period. Moving down the attachment to assess the "sensitivity" pricing scenarios, Option #2 is more costly by amounts ranging from $272 million for the "Higher Band" price scenario, to $230 million for the "Lower Band" pricing scenario.

Q. WHAT ADDITIONAL OBSERVATIONS AND CONCLUSIONS CAN YOU DRAW FROM THE ECONOMIC COMPARISONS OFFERED IN ATTACHMENTS SCW-4-1 AND SCW-4-2?

A. In general, the Plexos® results summarized in Attachment SCW-4-1 and Attachment SCW-4-2 indicate that, as compared to Option #2, the Rockport

Unit 2 SCR Project—reflected in both Option #1A *and* Option #1B—is economically-favored across the full range of long-term pricing scenarios modeled. Therefore, assessing these modeled CPW differences between "Option #1A / Option #1B" and Option #2 that are reflective of these significantly discrete long-term fundamental commodity pricing elements—i.e., inclusive of an approximate -1.0/+1.0 standard deviation around volatile natural gas pricing[33]—it would indicate that a nearer-term solution that would call for the retrofitting of Rockport Unit 2 with SCR technology by December 31, 2019, would be the most economical option for I&M and its customers.

Further, Option #1A represents a unit disposition alternative that is intended to offer a potential longer-term perspective around the economic viability of Rockport Unit 2. As previously indicated in this testimony, however, any decisions around the subsequent required environmental retrofits for that unit—chiefly, a DFGD installation by December 2028—would be considered as part of a future CPCN application before this Commission. What the relative "Option #1A versus Option #1B" economics *would* indicate is that it is currently "too close to call" in terms what that future disposition of the unit might be *beyond* what has clearly been demonstrated for Option #1B (i.e., through the unit's potential Lease termination date of December 2022). Therefore, the results suggest 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

[33] See TABLE 4 pricing scenario descriptions.

over the long-term (Option #1A) by ultimately retrofitting it with DFGD technology as required under the Modified Consent Decree.

IX. <u>"CARBON" RISK ASSESSMENT</u>

Q. DID I&M CONSIDER THE PROSPECTS FOR POTENTIAL FUTURE CARBON REGULATION IN THIS ECONOMIC ANALYSIS?

A. Yes. As discussed in TABLE 4 and immediately thereafter, the Company considered—as a cost/valuation "proxy" for modeling purposes—a presumed "carbon tax" effective in the year 2022. As identified on Attachment SCW-2, the level of this carbon tax that was incorporated into the long-term fundamental pricing forecast initiates on the order of $15 per tonne ('real' [2014] dollars) and was incorporated for not only the 'BASE' alternative pricing scenario, but was also applied in the respective 'Lower Band' and 'Higher Band' alternative scenarios. Hence, the modeling results inherently considered the relative dispatch cost "penalty" attributable to the generation costs of higher-CO_2 emitting coal-fired resources—such as Rockport Unit 2—vis-à-vis other (non-coal) resource alternatives.[34] Recognizing this penalty, however, the Plexos® long-term, life cycle study period results previously summarized continued to point to the SCR-retrofit "Option #1" (*either* "Option #1A" or "Option #1B") as being the least-cost unit disposition option for Rockport Unit 2.

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

Q. WERE THE IMPLICATIONS OF EPA'S FINAL CLEAN POWER PLAN SPECIFICALLY REFLECTED IN THE MODELED ECONOMIC EVALUATIONS FOR ROCKPORT UNIT 2?

A. No, not specifically. Given that the final CPP rulemaking was released relatively recently,[35] the states—including Indiana—have yet to potentially offer binding state implementation plans, its underlying complexity, as well as on-going legal challenges; it was not reasonable to attempt to address/model elements of the rule. Moreover, as indicated by Company witness Hendricks, I&M is currently in the process of reviewing these rulemakings and must undertake significant new analyses to understand the impacts of the final CPP working with other stakeholders in the coming months and years to better understand the requirements of the final CPP, and to work with state agencies on the state's response to it.

The final CPP did not seek to establish a carbon price, or "tax", in order to achieve reduction of CO_2 emissions from fossil generation units. Rather, as more fully described by Mr. Hendricks, the rule is centered on the achievement of future state-specific CO_2 emission reduction targets that were predicated on a set of suggested "building block" metrics. Despite that complexity and uncertainty, it was reasonable to attempt to at least "proxy" the potential relative economic implication on Rockport Unit 2 via assessing the impact of such CO_2/carbon pricing would have on generation/output. This was accomplished through the (incremental) variable/dispatch cost 'penalization' of the coal-fired Rockport Unit 2 via the introduction of such a

[35] Publically released on August 3, 2015; and published in the *Federal Register* on October 23, 2015.

CO_2/carbon pricing proxy. By way of incorporating these carbon pricing proxies, the Company believes—as supported by the testimony of Mr. Hendricks—it has reasonably estimated the potential impact of the Clean Power Plan on Rockport Unit 2. This includes the incorporation of a "High Carbon" pricing scenario which was determined by the AEP Fundamental Analysis as being a higher-than-anticipated threshold level of CO_2 pricing approximately *two-thirds above* the level assumed in the 'BASE' pricing scenario, or at an adjusted level of roughly $25 per tonne (real [2014] dollars), also effective in the year 2022.

Q. WHAT DID THOSE PLEXOS® MODELING RESULTS INDICATE?

A. As previously summarized in this testimony and on Attachment SCW-4-1, when incorporating a $15 per tonne (real) CO_2 pricing proxy as part of the "BASE" pricing scenario, the Option #1A alternative continued to be economically advantaged versus either of the "Option #1B" and "Option #2" (return and replace) alternatives by amounts ranging from $84 million (vs. Option #1B) to $322 million (vs. Option #2). Alternatively, when incorporating the 'High Carbon' $25 per tonne (real) CO_2 pricing proxy, the Option #1A alternative was now slightly more costly than Option #1B by $90 million; while it continued to be economically advantaged versus Option #2 by $142 million.

Q. WHAT ARE THE IMPLICATIONS OF CO_2/CARBON WHEN ASSESSING THE RELATIVE *SHORTER-TERM* DECISION AROUND THE ROCKPORT 2 SCR PROJECT WHEN COMPARING OPTION #2 and OPTION #1B, ONLY?

A. Over the relative shorter term, the results suggest that CO_2 would likely not be a significant issue. Recognizing that, effectively, Option #1B and Option #2 are *largely focused on the relative economics of those alternatives for the years 2020 through 2022 (only)*, one would anticipate that by virtue of a 2022 start-date for the CPP (represented by a 2022 carbon tax proxy start-date in the modeling), it would have minimal impact on the relative economic results. This fact is borne out when comparing the relative results found on Attachment SCW-4-2. When examining the (CPW) cost differences between Option #2 and Option #1B, one would note that even under varying long-term commodity pricing scenarios—including "High Carbon" and "No Carbon" scenarios—the results are nearly the same. This indicates that the relative make-up of these respective option views is largely the same *post*-2022. In other words, both cases assume Rockport Unit 2 would be returned to the Lessors and replaced with comparable (non-coal) resources at that point which would largely mitigate any relative cost exposure tied to CO_2/carbon.

Considering further that the recent U.S. Supreme Court decision to stay the CPP could potentially result in the rule's implementation being delayed by one or more years beyond 2022—under the further assumption that the Court would ultimately re-instate the rule—would suggest that CO_2/carbon will likely have no bearing on this nearer-term decision to install an SCR on Rockport Unit 2.

X. OPTIONALITY OFFERED BY THE ROCKPORT UNIT 2 SCR PROJECT

Q. YOUR TESTIMONY HAS PREVIOUSLY MENTIONED THE "OPTIONALITY" THAT WOULD BE AFFORDED I&M AND ITS CUSTOMERS BASED ON A DECISION TO ALLOW ROCKPORT UNIT 2 TO CONTINUE TO OPERATE BY WAY OF INSTALLING THE SCR PROJECT. PLEASE ELABORATE.

A. The Rockport Unit 2 SCR Project could potentially serve to "bridge" the unit for a period of 9 years; beginning with the required December 2019 SCR in-service date up to the timeframe in which a more capital-intensive DFGD retrofit which, for purpose of the analysis, would be required to be installed by December 31, 2028. For instance—as outlined on TABLE 3—at an installed capital cost of $189/kW, the Rockport Unit 2 SCR Project would be just a fraction of the cost of either replacement-build CC, CT, AD and/or CHP resources.

Attachment SCW-5, offers a shorter-term (*i.e.*, 13-year; 2016-2028) CPW comparison of the Option #1A versus Option #2 alternatives. It demonstrates that the relative economic advantage of Option #1A versus Option #2 over this shorter timeframe (through 2028) is apparent. That relative CPW benefit is, on average, nearly $43 million per year—compared to an average per year advantage of nearly $9 million over the full modeled long-term optimization period, including end-effects. This would suggest that the Rockport Unit 2 SCR Project would offer significant relative option value over the period *leading up to* the next potential major re-investment; the installation of DFGD by the end of 2028.

Q. WOULD THIS RELATIVE NEAR-TERM ECONOMIC ADVANTAGE ALSO BE APPLICABLE FOR THE EVEN SHORTER PERIOD LEADING UP TO THE POTENTIAL "RETURN TO LESSOR" DISPOSITION ALTERNATIVE UNDER OPTION #1B?

A. Yes, even more so. Attachment SCW-5 also offers a shorter-term (*i.e.*, 7-year; 2016-2022) CPW comparison of the Option *#1B* versus Option #2 alternatives. It demonstrates that the relative economic advantage of Option #1B versus Option #2 over this shorter timeframe (through 2022) is even *more* pronounced, with the CPW benefit being, on average, approximately $65 million per year.

In summary, this would also suggest that the Rockport Unit 2 SCR Project would afford the ability to capitalize on significant relative value it would offer I&M and its customers; even for a brief, 3-year period that would lead up to a potential Return to Lessor disposition.

XI. VALIDATION OF RESULTS VERSUS I&M'S 2015 IRP

Q. EARLIER YOUR TESTIMONY INDICATED THAT THE OPTIONS ANALYZED WERE CONSISTENT WITH CERTAIN "CASES" OFFERED AS PART OF I&M'S RECENT IRP FILING (TABLE 2). HOW DID THE ECONOMIC RESULTS COMPARE BETWEEN THOSE ANALYSES?

A. Attachment SCW-6 provides a comparison of the relative CPW differentials between the results set forth in the 2015 IRP[36] and these instant results. For example, this demonstrates that the 'CPW cost difference' between Option

[36] I&M 2015 IRP; Table 22 (pg. 120)

#1B and Option #2 under BASE pricing, as shown on Attachment SCW-4-2, was $239 million. The relative "as-filed" CPW cost difference for the comparable options from the IRP was $465 million. However, subsequent to the IRP filing it was determined that there was an overstatement of cost of approximately $205 million in the development of the "Fleet Modification w/ NO RK U2 SCR" IRP case results. Therefore the "as-corrected" CPW cost difference is restated at $260 million, or, nearly the same figure as the current analysis.

Also note that the CPW cost difference between Option #1A and Option #1B, as shown also on Attachment SCW-4-1, was $84 million. The relative "as-filed" CPW cost difference for the comparable options from the 2015 IRP was $174 million. This difference was a function of having utilized an updated set of Rockport Plant long-term projections for plant O&M expense and capital expenditures that was established subsequent to the development of the IRP.

Q. WERE THERE OTHER MATERIAL DIFFERENCES BETWEEN THE UNDERLYING DATA PARAMETERS AND ASSUMPTIONS UTILIZED IN I&M's 2015 IRP AND THIS LATEST ROCKPORT UNIT 2 DISPOSITION ANALYSIS?

A. No. As indicated earlier one of the major underpinnings of such analyses, long-term fundamental commodity pricing projections were the same as those pricing forecasts used in the IRP. Further, the underlying I&M load and peak demand forecast utilized is also identical to the forecast used in the IRP. Additionally, the cost and performance parameters associated with the alternative replacement resources (including, CC, CT, AD, CHP, wind, solar and incremental DSM) were all consistent with the parameters employed in I&M's recently-submitted 2015 IRP.

Q. WOULD THE CONCLUSION THAT INSTALLING AN SCR ON ROCKPORT UNIT 2 IS THE SUPERIOR OPTION CHANGE *EVEN IF* DIFFERENT ASSUMPTIONS HAD BEEN UTILIZED AS PART OF THIS POST-IRP ANALYSIS?

A. No. For instance, as this testimony suggests, if the decision materially boils down to the comparison of two "nearer-term" options—*Option #1B versus Option #2*—then both of these options would likely require the same level and type of replacement resources beginning in roughly the same timeframe—2023 (Option #1B) versus 2020 (Option #2). Therefore the relative CPW cost difference between those two views would not be materially impacted *irrespective* of the assumptions supporting those replacement resources—including long-term fundamental pricing and load projections—as each of those options would be impacted nearly equivalently.

To validate this point, a sensitivity option was performed which served to "delay" the Rockport Unit 2 replacement resources required under Option #2 by three years (i.e., from 1/2020 -to- 1/2023), or a disposition date *consistent* with Option #1B. As reflected on Attachment SCW-4A, those changes resulted in "(Sensitivity) Option #2A" having relative small CPW cost changes versus Option #2. In fact, under BASE pricing, this Option #2A would now be even more costly versus Option #1A by $346 million (as compared with a $322 million CPW cost difference when comparing Option #2 versus Option #1A).

Further, recall that when examining the results on Attachment SCW-4-2 the relative CPW cost differences between Option #2 and Option #1B are fairly insignificant (ranging from $230 million -to- $272 million, only) *irrespective* of the varied fundamental commodity pricing projection assumed, including natural gas and carbon.

XII. CONCLUSIONS AND RECOMMENDATIONS

Q. DO THE ROCKPORT UNIT 2 DISPOSITION ANALYSES YOU HAVE DESCRIBED EXAMINE THE CRITERIA SET FORTH IN INDIANA CODE § 8-1-8.7-3(b)(7) AND § 8-1-8.7-3(b)(8)?

A. Yes. As it pertains to part (b)(7), the Company has set forth the relative cost and feasibility of a Rockport Unit 2 retirement (or, in this circumstance, return to Lessors) option and demonstrated that the cost of that alternative would exceed that of the proposed Rockport Unit 2 SCR Project.

In regard to part (b)(8), the Company has likewise implicitly set forth that the dispatch priority of this proposed NO_X-controlled Rockport Unit 2 will not be adversely impacted based on the resulting variable cost profiles within the economic analyses previously described. It would be anticipated that the unit's annual capacity factor will not be significantly different from levels had this SCR retrofit not been installed.

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

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

(1) I&M has performed robust unit disposition economic analyses that would point to the nearer-term retrofitting of Rockport Unit 2 with SCR technology by December 31, 2019 (via either Option #1A or Option #1B) as being a reasonable and least-cost solution over the long-term economic study period evaluated when compared to a view that would not install an SCR but rather terminate the Rockport Lease as of that same date and paying the Lessors a stipulated Lease Termination Value (Option #2).

(2) The Rockport Unit 2 SCR Project would serve to economically preserve a future option to potentially install DFGD environmental controls on Unit 2 by the end of 2028, as required under the Modified Consent Decree. However, even under the assumption I&M would ultimately choose *not* to proceed with a Unit 2 DFGD retrofit, the economic analysis clearly supports implementation of the Rockport Unit 2 SCR Project.

(3) It is in the best interest of its customers to leverage the current investment of a thermally-efficient Rockport Unit 2 by recommending it be retrofitted with SCR technology by December 31, 2019, so as to be in compliance with the Modified Consent Decree as well as other potential EPA rulemaking that would require the reduction of NO_X emissions.

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

A. Yes.

VERIFICATION

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

Date: 10/19/16

Scott C. Weaver

Attachment SCW-1

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

I. RESOURCE NEED

A. Description of I&M's customer base

I&M's customer base consists of both retail and sales-for-resale customers located in northern Indiana and southern Michigan. Approximately 587,000 residential, commercial, industrial and other retail end-use customers are served by the Company; with approximately 459,000 residing in Indiana. These I&M-Indiana retail customers represent over 66 percent of I&M's total (retail and wholesale) energy sales in 2015, with the balance coming from retail sales to customers in Michigan, as well as FERC-authorized sales to several electric cooperatives and municipalities that provide wholesale service for ultimate distribution and resale to their end-use customers.

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

To ensure the continuation of reliable service, the peak demand of its customer base represents one of the primary underpinnings of any capacity resource plan. The peak load requirement of all I&M retail and sales for resale wholesale customers is seasonal in nature, with distinctive peaks occurring in both the summer and the winter seasons. Historically, I&M's larger peak demand has been recorded in the summer season, with the all-time actual peak being 4,837 MW, which occurred on July 21, 2011 (4,479 MW on a "weather-normalized", non-PJM coincident basis).[1]

The following **Table 1-1** offers the AEP Economic Forecasting June, 2015 projection of I&M and, for comparison, overall AEP-East (summer) peak demand and internal load, with peaks adjusted to recognize overall PJM zonal diversity. Over the next 10 year period (through 2025) I&M's summer demand is anticipated to remain relatively flat with a compound annual growth rate ("CAGR") of only 0.04 percent, or by a total of 17 MW; relative results which are below those of the overall AEP-East region for the same period. The peak demand CAGR for I&M does increase to 0.22% over the next 20 years, or by a total of 182 MW.

[1] I&M's most recent annual (2015) actual summer peak was 4,398 MW, occurring on July 28, 2015 (4,528 MW on a weather-normalized, non-PJM coincident basis).

Table 1-1

Forecasted (Summer) Peak Demand and Internal Load
I&M (Total Company) and AEP-East
Internal Forecast BEFORE DSM, with Implied PJM (Peak) Diversity Factor
(June-2015 Fcst)

	Peak Demand (MW)		Internal Load (GWh)	
Year	**I&M**	AEP-East*	**I&M**	AEP-East*
2016	**4,277**	19,555	**25,753**	120,199
2017	**4,292**	19,839	**25,854**	121,873
2018	**4,216**	19,830	**25,351**	121,613
2019	**4,223**	19,890	**25,396**	121,880
2020	**4,218**	19,917	**25,432**	122,194
2021	**4,238**	20,041	**25,485**	122,583
2022	**4,252**	20,138	**25,551**	123,061
2023	**4,258**	20,207	**25,615**	123,546
2024	**4,267**	20,266	**25,674**	123,987
2025	**4,293**	20,406	**25,735**	124,384
2026	**4,311**	20,508	**25,801**	124,803
2027	**4,329**	20,607	**25,867**	125,241
2028	**4,339**	20,683	**25,946**	125,759
2029	**4,360**	20,802	**26,020**	126,229
2030	**4,376**	20,910	**26,079**	126,658
2031	**4,392**	21,018	**26,128**	127,065
2032	**4,397**	21,082	**26,187**	127,514
2033	**4,427**	21,245	**26,262**	128,007
2034	**4,439**	21,325	**26,340**	128,501
2035	**4,459**	21,444	**26,417**	128,987
10-Year (2016-2025):				
Total Growth	**17**	851	**(18)**	4,186
Compound Annual Growth Rate	**0.04%**	0.47%	**-0.01%**	0.38%
20-Year (2016-2035):				
Total Growth	**182**	1,889	**664**	8,789
Compound Annual Growth Rate	**0.22%**	0.49%	**0.13%**	0.37%

* AEP-East includes Ohio-Wires customers

C. PJM reserve margin criterion

It is assumed that the underlying *minimum* reserve margin criteria to be utilized in the determination of I&M's capacity needs assessment is the PJM board-approved Installed Reserve Margin ("IRM") level. Currently that IRM level is 16.4 percent; but will be increasing to 16.5 percent effective with the most recently-established, 2019/20, PJM (3-year forward) planning year. For long-term resource planning purposes, it is assumed this latter level will remain through the Company's 20-year long-term planning period.

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

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

Further, beginning in the initial 2007/08 PJM "planning year", through today—*i.e.,* for the most recently-established 2019/20 planning year—AEPSC, as agent for the AEP-East LSEs, including I&M, has given annual notice of its intent to elect to continue to opt-out of the PJM Reliability Pricing Model ("RPM") three-year forward capacity auction and, instead, meet its capacity resource obligation through participation in the optional, FERC-authorized Fixed Resource Requirement ("FRR") construct. FRR requires AEP and I&M to set forth its future capacity resource profile and position under, essentially, a "self-planning" format that is predicated upon ensuring the stand-alone achievement of its future customer peak demand *plus* IRM requirements (*i.e.*, 'UCAP Obligation'). The current AEP Power Coordination Agreement ("PCA") offers a loosely-integrated arrangement in which the participating operating companies (I&M, APCo and KPCo) are expected to be self-sufficient for both capacity and energy requirements. Despite that PCA requirement, these three AEP affiliates have continued to elect to opt-out of the capacity auction and participate jointly as an "FRR" planning entity, at least through the 2019/20 Planning Year, so as to enjoy a) the inherent capacity position hedging capabilities offered to a larger-scale planning entity; and b) a lower overall IRM requirement vis-à-vis the implied reserve margin that have resulted from prior cleared RPM capacity auctions.

Currently it is I&M's position that the interests of its customers are better preserved under that FRR framework. While I&M, and the other AEP-East operating company participants in the PCA—beginning with the *next* (2019/20) PJM-RPM planning year—reserve the option of electing to participate in future RPM 3-year forward auction process.

E. Capacity Performance

On June 9, 2015 FERC issued an order largely accepting PJM's proposal to establish a new "Capacity Performance" product. The resulting PJM rule requires future capacity auctions to transition from current or 'Base' capacity products to Capacity Performance products. Capacity Performance resources would be held to stricter requirements than current Base resources and, with that, could be assessed additional charges for UCAP sources failing to deliver energy when called upon during an (hourly) emergency performance event or, potentially, receive credits if anticipated delivered energy during such events were at levels above offered UCAP amounts for those sources.

I&M and AEP are in the process of reviewing the full implications of the order and recognizing that final tariffs addressing Capacity Performance have not been issued by PJM. Despite this uncertainty, this IRP incorporates the following assumptions for Capacity Performance values as it pertains to certain intermittent resources, in order to address this potential Capacity Performance rulemaking, anticipated to be fully-effective with the 2020/21 PJM planning year:

- Run-of-River hydro unit nameplate capacity will offer no capacity value due to the intermittency of supply.
- Wind resources will also offer no capacity value due to the intermittency of its supply, a reduction from current PJM's criterion limiting UCAP contribution to 13 percent (of nameplate) for new wind sources.
- Solar resources will be valued at the 'full' 38 percent of nameplate capacity rating, which represents the current PJM UCAP limitation criterion for new solar resources.

This long-term I&M capacity profile assumes that during the 2020/21 PJM planning year all capacity resources will need to be Capacity Performance products. *It is possible that these resources may ultimately be combined, or "coupled", and offered into the PJM market as Capacity Performance resources.* Once the final PJM Capacity Performance tariffs are approved and published, the Company will investigate methods to maximize the utilization of its current (and future) intermittent resource portfolio within that construct. An example could be the additional coupling of run-of-river hydro, wind and potential solar resources in a way that would mitigate non-performance risk. While there could be some uplift in intermittent resource UCAP contribution from such a potential 'coupling' approach, it would be anticipated any additional amounts would be neglible in the context of the possible replacement of the Company's 1,105 MW share of Rockport Unit 2.

F. I&M's current available capacity resources

To meet the most recent UCAP Obligation and annual energy requirements of its customers, as part of its FRR obligations in PJM for the current 2016/17 "delivery year", I&M is relying on 4,524 MW of owned—or for which it currently has a long-term purchase entitlement—generating capability. The make-up of I&M's PJM-recognized installed capability ("ICAP") includes a portfolio of generating resources identified in the following **Table 1-2**:

Table 1-2

COAL:

- ✓ Rockport Unit 1 (658 MW) located in Spencer County, IN. In-service 1984
- ✓ Rockport Unit 2 (650 MW) located in Spencer County, IN. In-service 1989
- ✓ Rockport Unit 1 (460 MW) located in Spencer County, IN. [2] In-service 1984
- ✓ Rockport Unit 2 (455 MW) located in Spencer County, IN. [3] In-service 1989

NUCLEAR:

- ✓ D.C. Cook Unit 1 (1,006 MW) located in Bridgeman, MI. In-service 1975
- ✓ D.C. Cook Unit 2 (1,053 MW) located in Bridgeman, MI. In-service 1978

[2] This reflects I&M's 70% purchase entitlement from the (50%), AEP Generating Company (AEG) ownership share of the (total) 1315 MW unit.

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

HYDRO:

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

WIND [4]:

- ✓ Fowler Ridge Wind Farm (18 MW) located in Benton County, IN. In-service 2009
- ✓ Wildcat Wind Farm (13 MW) located in Grant, Howard, Madison and Tipton Counties, IN. In-service 2013
- ✓ Headwaters Wind Farm (26 MW) located in Randolph County, IN. In-service 12/2014

SOLAR [5] [6]:

- ✓ Deer Creek Solar facility (1.1 MW) located in Marion, IN. In-service 12/2015

Plus:

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

TOTAL (2016/2017 PJM Planning Year) **4,524** MW

Note: Tanners Creek Units 1-4 were retired on June 1, 2015

G. Anticipated future capacity rerates

Nearly concurrent with the planned Rockport Unit 2 (and Unit 1) SCR retrofits in late-2019 and late-2017, respectively, current planning also projects both units would be uprated by a total of 36 MW (each) to reflect the benefits of the AEP System's LP Turbine improvement program. Likewise, D. C. Cook Unit 2 is

[4] Recognizing the intermittent nature of *wind* resources, for PJM ICAP-determination purposes, this represents the PJM-recognized initial 13 percent portion of the total nameplate rating from I&M's share of the (150-MW, combined) Fowler Ridge I & II Renewable Energy Purchase Agreements (REPA), the (100-MW) Wildcat REPA, and the (200-MW) Headwaters REPA. Note, however, that the subsequent PJM-authorized capacity rating for I&M's share of Fowler I & II has been decreased to a total of 13 MW from the initial in-service recognized level of 19.5 MW (150 MW x 13%). In all cases, however, this 13 percent level of ICAP determination is assumed to be reduced to zero beginning with the full implementation of the PJM-RPM "Capacity Performance" construct effective with the 2020/21 planning year.

[5] Recognizing the intermittent nature of *solar* resources, for PJM ICAP-determination purposes, this represents the PJM-recognized initial 38 percent portion of the total nameplate rating from I&M's share of the Company-owned (2.9-MW) Deer Creek solar facility. Likewise, however, this 38 percent level of ICAP determination is assumed to remain at 38 percent effective with the full implementation of the PJM-RPM Capacity Performance construct effective with the 2020/21 planning year.

[6] In addition to the 1.1 MW (2.9 MW nameplate) Deer Creek facility, this does not include three additional I&M solar facilities that are anticipated to be placed into service over the course of 2016, making each not applicable for PJM planning purposes until the subsequent, 2017/18 planning year (Olive solar facility @ 1.9 MW [4.9 MW nameplate]; Twin Branch solar facility @ 1.1 MW [2.9 MW nameplate]; and Watervliet solar facility @ 1.7 MW [4.6 MW nameplate]). This will bring the total solar contribution for I&M in PJM to 5.8 MW (approximately 15 MW nameplate).

projected to experience a 50 MW uprate in late-2016 to reflect a currently-planned HP/LP Turbine replacement. Such uprates would impact the Company's ICAP beginning with the subsequent PJM-RPM planning years.[7]

H. I&M's anticipated "demand" resources (DSM)

Demand-Side Management ("DSM") comprised of both "active" and "passive" demand reduction initiatives has been incorporated into the Company's resource planning. Specifically, "active" DSM, in the form of peak-reducing demand response activity has been projected; as well as "passive" DSM, in the form of "around-the-clock" energy efficiency ("EE") programs, which I&M and this Commission has supported for some time, has also been incorporated in the analysis. The following **Table 1-3** identifies the level of I&M (total) demand reduction and EE that are initially anticipated over the forecasted time horizon. Such projected levels of EE were embedded into the Company's long-term load forecast.

While not at all trivial, it is evident however, that even the aggressive demand resource contributions already forecasted for such DSM activity by or around the year 2020 of 363 MW—summarized in Table 1-3—are well below the significant capacity needs that would be at issue when considering the disposition of units on the scale of, particularly, Rockport Unit 2. Likewise, any *incremental* levels of DSM/EE activity over-and-above the projected levels incorporated into I&M's long-term load forecast that could result from the unit's disposition evaluation would also likely provide a very small relative offset to the native generation offered to I&M's resource portfolio by Rockport Unit 2 (1,105 MW as reflected in Table 1-2).

[7] For example, the Rockport Unit 2 (turbine) uprate in "late-2019" would impact I&M's capacity position beginning with the 2020/21 PJM-RPM planning year.

Table 1-3

Forecasted Demand Response (DR) and Energy Efficiency (EE)
I&M (Total Company) and AEP-East
(June-2015 Fcst)

	(CURRENT) "ACTIVE" PJM-APPROVED DEMAND RESPONSE Peak Reduction (MW)		+ (PROJECTED) "PASSIVE" DEMAND RESPONSE (ENERGY EFFICIENCY) Peak Reduction (MW)		= TOTAL DEMAND RESPONSE Peak Reduction (MW)	
Year	I&M	AEP-East*	I&M	AEP-East*	I&M	AEP-East*
2016	**315**	630	**26**	134	**341**	764
2017	**315**	671	**37**	187	**352**	858
2018	**315**	671	**48**	243	**363**	914
2019	**298**	678	**57**	290	**355**	968
2020	**298**	678	**64**	324	**363**	1,002
2021	**298**	678	**69**	350	**368**	1,028
2022	**298**	678	**73**	371	**371**	1,049
2023	**298**	678	**71**	385	**369**	1,063
2024	**298**	678	**75**	394	**374**	1,072
2025	**298**	678	**76**	402	**375**	1,080
2026	**298**	678	**77**	406	**375**	1,084
2027	**298**	678	**77**	408	**376**	1,086
2028	**298**	678	**77**	409	**376**	1,087
2029	**298**	678	**77**	410	**376**	1,088
2030	**298**	678	**78**	412	**376**	1,090
2031	**298**	678	**78**	414	**376**	1,092
2032	**298**	678	**78**	415	**377**	1,093
2033	**298**	678	**79**	418	**377**	1,096
2034	**298**	678	**79**	418	**377**	1,096
2035	**298**	678	**79**	420	**377**	1,098

	(PROJECTED) CUMULATIVE ENERGY EFFICIENCY (GWh)	
Year	I&M	AEP-East*
2016	**191**	788
2017	**268**	1,056
2018	**345**	1,347
2019	**416**	1,593
2020	**475**	1,781
2021	**517**	1,913
2022	**542**	2,018
2023	**558**	2,094
2024	**568**	2,145
2025	**574**	2,177
2026	**578**	2,195
2027	**580**	2,204
2028	**582**	2,212
2029	**584**	2,221
2030	**586**	2,230
2031	**588**	2,239
2032	**589**	2,248
2033	**591**	2,256
2034	**593**	2,264
2035	**595**	2,272

Reflects forecasted DR and EE levels embedded into the Company's June-2015 load & peak demand forecast… This would exclude 'incremental' levels of such resources that would result from the Rockport Unit 2 disposition evaluation performed.

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

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

Assuming that the I&M LSE was viewed individually as part of a PJM-planning perspective, the following **Table 1-4** offers a long-term (20-year) overview of such an I&M "stand-alone" capacity position within PJM though the 2035/36 PJM planning year. This view effectively assumes that the Company would continue to elect to participate in the PJM-RPM as an FRR (*i.e.*, self-planning) entity as opposed to participating in PJM's capacity auction construct. Further it assumes, as a "going-in"—or base assumption—that Rockport Unit 2 (and Unit 1) would continue to contribute ICAP throughout the planning horizon. As reflected in the Table 1-4 column identified as "Net Position w/ New Capacity" (col. 20), I&M would be "long" capacity by 159 MW beginning with the most recent (2019/20) 3-year forward PJM-RPM Base Residual Auction planning year.[8] This demonstrates and confirms that, not surprisingly, I&M would immediately be *significantly* exposed—from a stand-alone planning perspective—should a Rockport Unit 2 disposition strategy call for the unit to be returned to the Lessor.

In summary, based on the recommendations set forth in this testimony and, again, assuming that the I&M LSE were viewed individually as part of a PJM-planning perspective, Table 1-4 offers an overview of such an I&M stand-alone capacity position within PJM assuming the Company would continue to elect to be an FRR planning entity. It offers a "going-in" I&M capacity position profile over the next 20 years—*i.e.,* **before** the addition of incremental Plexos® model-selected resources—that reflect, <u>in addition to the recommended December 2019 "Rockport Unit 2 SCR Project" retrofit</u>, the:

- continued advancement of significant demand-side reduction (see Table 1-3);
- ultimate retrofit of Rockport Unit 1 with SCR and DFGD by December 2017 and December 2025, respectively;
- ultimate retrofit of Rockport Unit 2 with DFGD by December 2028; and
- although no ultimate disposition determination has been made, the potential for the retirement of the first D.C. Cook Nuclear Unit (Unit 1) in 2035 at the end of its initial (20-year) relicensing period.

[8] Stated another way, I&M would have 159 MW of capacity resources above the <u>minimum</u> PJM-FRR Installed Reserve Margin criterion of 16.5 percent.

Table 1-4 "Going-In" Capacity Position

INDIANA MICHIGAN POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (June 2015) Load Forecast
2016 (Going-In)

Planning Year		Obligation to PJM: Internal Demand (a)	DSM (b)	Projected DSM Impact (c)	Net Internal Demand	Interruptible Demand Response (d)	Demand Response Factor	Forecast Pool Req't (e)	UCAP Obligation	Net UCAP Market Obligation (f)	Total UCAP Obligation	Resources: Existing Capacity & Planned Changes (g)	Net Capacity Sales (h)	Planned Capacity Additions: Units	Planned Capacity Additions: MW (i)	Annual Purchases	Net ICAP	AEP EFORd (j)	Available UCAP	BASE UCAP Removed (l)	I&M Position (MW): Net Position w/o New Capacity	Net Position w/ New Capacity	PJM Reserve Margin: Total UCAP Obligation Less IDR and IRM	Installed Reserve Margin (IRM)	I&M Reserve Margin Above PJM IRM	Total I&M Reserve Margin
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)				
					=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)						=(11)-(12) + Sum(14) +(15)		=(16)*(1-(17))		=((11)-(12) +(15)) *(1-(17)) -(10)-(19)	=(18)-(10)-(19)				
2016 /17	(k)	4,213	(26)	0	4,213	223	0.953	1.095	4,381	0	4,381	4,524	12				4,512	3.90%	4,336	0	(45)	(45)	3,964	16.40%	-1.14%	15.26%
2017 /18	(k)	4,264	(37)	0	4,264	223	0.953	1.088	4,408	0	4,408	4,623	9				4,614	3.44%	4,455	0	47	47	3,982	16.50%	1.18%	17.68%
2018 /19	(k)	4,185	(48)	0	4,185	223	0.953	1.088	4,323	0	4,323	4,654	6				4,648	3.45%	4,488	0	165	165	3,909	16.50%	4.22%	20.72%
2019 /20	(k)	4,193	(57)	0	4,193	223	0.953	1.088	4,331	0	4,331	4,654	4				4,650	3.45%	4,490	0	159	159	3,916	16.50%	4.06%	20.56%
2020 /21		4,218	(64)	(26)	4,192	298	0.953	1.088	4,251	0	4,251	4,685	(65)				4,750	3.45%	4,586	73	262	262	3,915	16.50%	6.69%	23.19%
2021 /22		4,238	(69)	(37)	4,201	298	0.953	1.088	4,262	0	4,262	4,685	(65)				4,750	3.45%	4,586	73	251	251	3,924	16.50%	6.40%	22.90%
2022 /23		4,252	(73)	(48)	4,204	298	0.953	1.088	4,265	0	4,265	4,685	(64)				4,749	3.45%	4,585	73	247	247	3,927	16.50%	6.29%	22.79%
2023 /24		4,258	(71)	(57)	4,201	298	0.953	1.088	4,262	0	4,262	4,685	(64)				4,749	3.45%	4,585	73	250	250	3,924	16.50%	6.37%	22.87%
2024 /25		4,267	(75)	(64)	4,203	298	0.953	1.088	4,263	0	4,263	4,685	(64)				4,749	3.45%	4,585	73	249	249	3,925	16.50%	6.34%	22.84%
2025 /26		4,293	(76)	(69)	4,224	298	0.953	1.088	4,287	0	4,287	4,669	(65)				4,734	3.45%	4,571	73	211	211	3,945	16.50%	5.35%	21.85%
2026 /27		4,311	(77)	(73)	4,238	298	0.953	1.088	4,302	0	4,302	4,669	(65)				4,734	3.45%	4,571	73	196	196	3,958	16.50%	4.95%	21.45%
2027 /28		4,329	(77)	(71)	4,258	298	0.953	1.088	4,323	0	4,323	4,669	(65)				4,734	3.45%	4,571	73	175	175	3,976	16.50%	4.40%	20.90%
2028 /29		4,339	(77)	(75)	4,264	298	0.953	1.088	4,331	0	4,331	4,643	(65)				4,708	3.45%	4,546	62	153	153	3,983	16.50%	3.84%	20.34%
2029 /30		4,360	(77)	(76)	4,284	298	0.953	1.088	4,352	0	4,352	4,636	(65)				4,701	3.46%	4,538	55	131	131	4,001	16.50%	3.27%	19.77%
2030 /31		4,376	(78)	(77)	4,299	298	0.953	1.088	4,368	0	4,368	4,636	0				4,636	3.46%	4,476	55	52	53	4,015	16.50%	1.32%	17.82%
2031 /32		4,392	(78)	(77)	4,315	298	0.953	1.088	4,386	0	4,386	4,636	0				4,636	3.46%	4,476	55	34	35	4,030	16.50%	0.87%	17.37%
2032 /33		4,397	(78)	(77)	4,320	298	0.953	1.088	4,392	0	4,392	4,624	0				4,624	3.47%	4,464	42	29	30	4,036	16.50%	0.74%	17.24%
2033 /34		4,427	(79)	(77)	4,350	298	0.953	1.088	4,424	0	4,424	4,624	0				4,624	3.47%	4,464	42	(3)	(2)	4,063	16.50%	-0.05%	16.45%
2034 /35		4,439	(79)	(78)	4,361	298	0.953	1.088	4,436	0	4,436	4,598	0				4,598	3.49%	4,438	16	(15)	(14)	4,073	16.50%	-0.34%	16.16%
2035 /36		4,459	(79)	(78)	4,381	298	0.953	1.088	4,457	0	4,457	3,592	0				3,592	3.67%	3,460	16	(1,013)	(1,013)	4,091	16.50%	-24.76%	-8.26%

Notes: (a) Based on (June 2015) Load Forecast (with implied PJM diversity factor)

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

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

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

(e) Installed Reserve Margin (IRM) = 16.4%(2016), 16.5%(2017-2035)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

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

(g) Reflects the members ownership ratio of following summer capability assumptions:
I&M's share of AEP's OVEC capacity (43.47% PPR-share of full ~2,180 total capacity)
Assumes hydro units are derated to August average output in 2017/18
Wind Farm PPAs (Where Applicable)

(g) continued
EFFICIENCY IMPROVEMENTS:
2017/18: Cook 2: 50 MW (turbine)
2018/19: Rockport 1: 36 MW (turbine)
2020/21: Rockport 2: 36 MW (turbine)
FGD DERATES:
2025/26: Rockport 1: (18) MW
2028/29: Rockport 2: (18) MW
RETIREMENTS:
2015/16: Tanners Ck. 1-4
2035/36: Cook 1
2037/38: Cook 2

(h) Includes company's share of:
Estimated I&M nominations for PJM EE ('passive' DR program) levels
--reflected as a UCAP '<resource>'-- as part of PJM's emerging
auction products (eff: 2014/15)

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

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

(k) Represents yearly 'PJM- originated- forecast of AEP Zonal Load allocated to I&M and other AEP opcos based on 5CP

(l) Beginning with the 2020/21 PY, 'Base' UCAP levels will be reduced replaced (effectively reduced)
in recognition of the full impact of PJM's "Capacity Performance" tariff. Such reductive impacts being largely
anticipated for DR and intermittent (renewable) resources

Indiana Michigan Power Company
Attachment SCW-2

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

(Source AEP Fundamental Analysis, Mid-2015)

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

	NATURAL GAS (@ Henry Hub) ($/MMBtu)					CO2 ($/Metric Tonne)				
		Alternative Scenarios					*Alternative Scenarios*			
	'BASE' Forecast	Higher Band	Lower Band	No CO_2	High CO_2	'BASE' Forecast	Higher Band	Lower Band	No CO_2	High CO_2
	Carbon in 2022	Carbon in 2022	Carbon in 2022			Carbon in 2022	Carbon in 2022	Carbon in 2022		Carbon in 2022
2016	4.34	4.94	3.73	4.34	4.34	0.00	0.00	0.00	0.00	0.00
2017	5.09	5.80	4.38	5.09	5.09	0.00	0.00	0.00	0.00	0.00
2018	5.40	6.16	4.64	5.40	5.40	0.00	0.00	0.00	0.00	0.00
2019	5.50	6.27	4.73	5.50	5.51	0.00	0.00	0.00	0.00	0.00
2020	5.60	6.39	4.82	5.61	5.61	0.00	0.00	0.00	0.00	0.00
2021	5.82	6.64	5.01	5.74	5.83	0.00	0.00	0.00	0.00	0.00
2022	6.28	7.16	5.40	5.88	6.37	15.00	15.00	15.00	0.00	25.00
2023	6.60	7.52	5.68	6.02	6.79	15.29	15.29	15.29	0.00	25.47
2024	6.80	7.75	5.85	6.16	7.01	15.58	15.58	15.58	0.00	25.96
2025	6.96	7.94	5.99	6.31	7.18	15.88	15.88	15.88	0.00	26.47
2026	7.13	8.13	6.13	6.46	7.35	16.19	16.19	16.19	0.00	27.00
2027	7.30	8.32	6.28	6.62	7.53	16.51	16.51	16.51	0.00	27.52
2028	7.47	8.52	6.43	6.77	7.71	16.84	16.84	16.84	0.00	28.08
2029	7.65	8.73	6.58	6.94	7.90	17.17	17.17	17.17	0.00	28.62
2030	7.83	8.92	6.73	7.09	8.07	17.50	17.50	17.50	0.00	29.18
2031	8.00	9.12	6.88	7.25	8.25	17.85	17.85	17.85	0.00	29.74
2032	8.19	9.34	7.04	7.42	8.45	18.19	18.19	18.19	0.00	30.31
2033	8.39	9.57	7.22	7.60	8.66	18.54	18.54	18.54	0.00	30.90
2034	8.59	9.79	7.39	7.79	8.86	18.88	18.88	18.88	0.00	31.48
2035	8.80	10.04	7.57	7.98	9.08	19.24	19.24	19.24	0.00	32.07
2036	9.02	10.29	7.76	8.18	9.31	19.60	19.60	19.60	0.00	32.66
2037	9.24	10.53	7.94	8.37	9.53	19.95	19.95	19.95	0.00	33.26
2038	9.45	10.77	8.12	8.56	9.74	20.33	20.33	20.33	0.00	33.87
2039	9.66	11.01	8.31	8.76	9.96	20.69	20.69	20.69	0.00	34.49
2040	9.87	11.25	8.49	8.95	10.18	21.08	21.08	21.08	0.00	35.12
2041	10.08	11.49	8.67	9.14	10.40	21.46	21.46	21.46	0.00	35.77
2042	10.29	11.73	8.85	9.33	10.62	21.86	21.86	21.86	0.00	36.42
2043	10.50	11.97	9.03	9.52	10.83	22.26	22.26	22.26	0.00	37.09
2044	10.71	12.21	9.21	9.71	11.05	22.66	22.66	22.66	0.00	37.78
2045	10.92	12.45	9.39	9.90	11.26	23.08	23.08	23.08	0.00	38.47

	Coal-Illinois Basin (~4.3#) ($/Ton-FOB Mine)					Coal-PRB (~0.8#, 8400 Btu) ($/Ton-FOB Mine)				
		Alternative Scenarios					*Alternative Scenarios*			
	'BASE' Forecast	Higher Band	Lower Band	No CO_2	High CO_2	'BASE' Forecast	Higher Band	Lower Band	No CO_2	High CO_2
	Carbon in 2022	Carbon in 2022	Carbon in 2022		Carbon in 2022	Carbon in 2022	Carbon in 2022	Carbon in 2022		Carbon in 2022
2016	40.00	40.00	40.00	40.00	40.00	11.50	11.50	11.50	11.50	11.50
2017	42.25	44.36	40.56	42.25	42.25	12.30	12.91	11.81	12.30	12.30
2018	43.56	47.91	40.07	43.56	43.56	13.56	14.92	12.48	13.56	13.56
2019	45.92	52.80	40.41	45.92	45.92	14.74	16.95	12.97	14.74	14.74
2020	48.60	55.90	42.77	47.78	48.60	16.80	19.32	14.78	15.47	16.80
2021	50.19	57.72	44.17	49.72	50.19	17.97	20.67	15.81	16.24	17.97
2022	53.49	61.51	47.07	51.74	53.49	18.47	21.24	16.25	17.05	18.47
2023	51.01	58.67	44.89	53.84	51.01	16.88	19.41	14.85	17.90	16.88
2024	55.88	64.26	49.18	56.03	55.88	17.60	20.24	15.49	18.79	17.60
2025	56.30	64.75	49.55	58.30	56.30	18.91	21.75	16.64	19.72	18.91
2026	57.53	66.16	50.63	59.57	57.53	21.26	24.45	18.71	22.17	21.26
2027	57.91	66.59	50.96	59.96	57.91	20.19	23.22	17.77	21.05	20.19
2028	59.93	68.92	52.74	62.06	59.93	20.73	23.84	18.24	21.62	20.73
2029	64.10	73.71	56.41	66.37	64.10	24.40	28.06	21.47	25.44	24.40
2030	65.72	75.58	57.84	68.05	65.72	23.52	27.05	20.70	24.53	23.52
2031	68.05	78.26	59.89	70.47	68.05	26.64	30.64	23.44	27.78	26.64
2032	69.56	80.00	61.21	72.03	69.56	27.87	32.05	24.53	29.06	27.87
2033	74.69	85.89	65.73	77.34	74.69	30.21	34.74	26.58	31.50	30.21
2034	78.16	89.89	68.78	80.93	78.16	32.02	36.82	28.18	33.39	32.02
2035	80.24	92.27	70.61	83.08	80.24	36.36	41.81	32.00	37.92	36.36
2036	82.24	94.58	72.37	85.16	82.24	37.27	42.86	32.80	38.86	37.27
2037	84.30	96.94	74.18	87.29	84.30	38.20	43.93	33.62	39.84	38.20
2038	86.41	99.37	76.04	89.47	86.41	39.16	45.03	34.46	40.83	39.16
2039	88.57	101.85	77.94	91.71	88.57	40.13	46.15	35.32	41.85	40.13
2040	90.78	104.40	79.89	94.00	90.78	41.14	47.31	36.20	42.90	41.14
2041	93.05	107.01	81.88	96.35	93.05	42.17	48.49	37.11	43.97	42.17
2042	95.38	109.68	83.93	98.76	95.38	43.22	49.70	38.03	45.07	43.22
2043	97.28	111.88	85.61	100.73	97.28	44.09	50.70	38.79	45.97	44.09
2044	99.23	114.11	87.32	102.75	99.23	44.97	51.71	39.57	46.89	44.97
2045	101.21	116.40	89.07	104.80	101.21	45.87	52.75	40.36	47.83	45.87

	NATURAL GAS (@ Henry Hub) (REAL, 2014 $) ($/MMBtu)					ON-Peak Energy (PJM-AEP Gen Hub) ($/Mwh)				
		Alternative Scenarios					*Alternative Scenarios*			
	'BASE' Forecast	Higher Band	Lower Band	No CO_2	High CO_2	'BASE' Forecast	Higher Band	Lower Band	No CO_2	High CO_2
	Carbon in 2022	Carbon in 2022	Carbon in 2022			Carbon in 2022	Carbon in 2022	Carbon in 2022		Carbon in 2022
2016	4.24	4.83	3.64	4.24	4.24	35.34	37.02	33.47	35.45	35.93
2017	4.85	5.53	4.17	4.85	4.86	38.62	41.40	35.80	38.49	39.45
2018	5.02	5.72	4.32	5.02	5.02	40.37	44.71	36.56	39.91	41.13
2019	4.98	5.68	4.28	4.98	4.98	43.12	48.95	37.70	42.30	43.12
2020	4.94	5.64	4.25	4.95	4.95	44.97	50.62	39.24	43.72	44.14
2021	5.02	5.72	4.32	4.95	5.02	47.42	52.75	40.84	45.72	46.01
2022	5.30	6.04	4.56	4.96	5.37	62.04	68.03	54.53	47.48	66.45
2023	5.45	6.21	4.68	4.97	5.61	63.73	69.91	56.08	49.57	69.17
2024	5.50	6.27	4.73	4.98	5.67	66.89	73.74	58.81	52.11	71.74
2025	5.51	6.29	4.74	5.00	5.69	69.81	77.14	60.84	54.34	74.58
2026	5.53	6.30	4.75	5.01	5.70	72.39	79.74	62.57	56.19	76.58
2027	5.55	6.33	4.77	5.03	5.72	75.10	82.49	64.71	58.43	79.27
2028	5.57	6.35	4.79	5.05	5.75	77.21	85.22	67.04	61.04	81.56
2029	5.59	6.38	4.81	5.07	5.77	79.93	88.24	69.38	63.63	84.65
2030	5.61	6.39	4.82	5.08	5.78	82.57	91.07	72.16	66.79	87.57
2031	5.62	6.41	4.83	5.10	5.80	85.39	94.01	74.58	69.70	89.71
2032	5.64	6.43	4.85	5.11	5.82	88.74	96.88	77.29	72.60	92.88
2033	5.67	6.46	4.87	5.13	5.84	92.42	100.73	81.63	76.23	97.06
2034	5.69	6.49	4.90	5.16	5.87	93.33	103.51	84.22	78.19	98.26
2035	5.72	6.53	4.92	5.19	5.90	95.81	106.38	86.73	80.93	101.15
2036	5.75	6.56	4.95	5.22	5.93	99.04	108.87	88.52	83.67	103.17
2037	5.77	6.58	4.96	5.23	5.95	101.38	110.81	91.21	86.05	104.99
2038	5.79	6.60	4.98	5.25	5.97	104.70	115.45	94.18	89.79	107.76
2039	5.81	6.62	5.00	5.26	5.99	105.73	116.69	95.57	91.41	109.34
2040	5.83	6.64	5.01	5.28	6.01	108.64	118.55	98.11	95.19	112.11
2041	5.84	6.66	5.02	5.29	6.02	110.08	121.38	100.11	97.49	114.81
2042	5.85	6.67	5.03	5.30	6.03	112.43	123.40	100.64	98.76	115.24
2043	5.86	6.68	5.04	5.31	6.04	114.44	126.23	102.99	101.74	118.35
2044	5.87	6.69	5.05	5.32	6.05	115.92	127.70	104.53	103.79	120.12
2045	5.88	6.70	5.05	5.33	6.06	119.58	129.97	106.94	105.53	123.70

	OFF-Peak Energy (PJM-AEP Gen Hub) ($/Mwh)					Capacity Value (PJM-RTO RPM) ($/MW-Day)				
		Alternative Scenarios					*Alternative Scenarios*			
	'BASE' Forecast	Higher Band	Lower Band	No CO_2	High CO_2	'BASE' Forecast	Higher Band	Lower Band	No CO_2	High CO_2
	Carbon in 2022	Carbon in 2022	Carbon in 2022		Carbon in 2022	Carbon in 2022	Carbon in 2022	Carbon in 2022		Carbon in 2022
2016	26.65	27.17	26.19	26.63	25.73	91.30	91.30	91.30	91.30	91.30
2017	27.41	28.79	26.18	27.26	26.70	94.74	94.74	94.74	94.74	94.74
2018	28.22	30.89	25.94	27.71	27.37	187.37	225.68	225.68	225.68	171.28
2019	30.31	34.41	26.61	29.57	29.02	260.32	309.31	309.31	309.31	238.84
2020	32.05	36.23	28.08	30.61	29.94	287.24	317.35	317.35	317.35	276.25
2021	33.59	37.38	29.17	32.18	30.93	314.48	324.65	324.65	324.65	316.66
2022	47.94	51.96	43.25	33.74	52.16	331.79	331.79	331.79	331.79	331.79
2023	48.59	52.59	43.74	34.98	53.96	339.09	339.09	339.09	339.09	339.09
2024	50.93	55.45	45.63	36.98	55.70	346.21	346.21	346.21	346.21	346.21
2025	52.82	57.68	46.98	38.41	57.63	353.48	353.48	353.48	353.48	353.48
2026	54.98	60.02	48.49	40.13	59.55	360.90	360.90	360.90	360.90	360.90
2027	56.64	61.85	49.73	41.52	61.39	368.12	368.12	368.12	368.12	368.12
2028	58.27	63.80	51.00	43.20	62.86	375.48	375.48	375.48	375.48	375.48
2029	60.58	66.52	53.09	45.56	65.28	382.99	382.99	382.99	382.99	382.99
2030	62.38	68.60	54.88	47.58	67.30	390.65	390.65	390.65	390.65	390.65
2031	64.62	71.02	56.52	49.61	68.78	398.47	398.47	398.47	398.47	398.47
2032	66.97	73.38	58.39	51.79	71.55	406.44	406.44	406.44	406.44	406.44
2033	70.20	77.00	61.53	54.81	74.49	414.56	414.56	414.56	414.56	414.56
2034	71.58	79.59	63.39	56.44	75.76	422.44	422.44	422.44	422.44	422.44
2035	74.02	82.26	65.20	58.92	78.21	430.47	430.47	430.47	430.47	430.47
2036	76.49	84.53	66.78	60.70	79.73	439.08	439.08	439.08	439.08	439.08
2037	78.90	86.57	69.07	63.12	81.71	447.86	447.86	447.86	447.86	447.86
2038	81.50	90.72	71.48	66.45	84.39	456.81	456.81	456.81	456.81	456.81
2039	83.17	92.47	73.26	68.41	86.27	465.95	465.95	465.95	465.95	465.95
2040	85.64	94.61	75.41	71.16	88.75	475.27	475.27	475.27	475.27	475.27
2041	87.49	97.31	77.21	73.57	91.03	484.78	484.78	484.78	484.78	484.78
2042	89.33	99.27	78.30	75.28	92.14	494.47	494.47	494.47	494.47	494.47
2043	91.67	102.03	80.48	78.38	94.81	504.36	504.36	504.36	504.36	504.36
2044	93.50	103.75	82.15	80.51	96.68	514.45	514.45	514.45	514.45	514.45
2045	96.27	105.83	84.05	82.53	99.74	524.74	524.74	524.74	524.74	524.74

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

Indiana Michigan Power Company
Attachment SCW-3
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PUBLIC

Summary of Major Cost & Performance Paramenters Used in Modeling

(All Cost Estimates reflected in 'Nominal' $)

Rockport Unit 1...

	Rockport U1 (Total Unit -- initially, 1315 MW)													Rockport U1 (I&M Cost-Based Share [@85%])					
	Performance Parameter							Cost Parameter											
									Consumables					($000)					
	Unit Capability		Heat Rate	Avg.	Emission Rates			Delivered	Sodium	Activated	Anhydrous	Lime	Other	FOM			On-Going Capital*		
	Max (MW)	Min (MW)	-Avg Annual- (Btu/kWh)	Availability (%)	SO_2 (lb/MMBtu)	NO_x (lb/MMBtu)	Hg (lb/Trillion Btu)	Fuel Cost ($/MMBtu)	Bicarb (DSI) ($/MMBtu)	Carbon (ACI) ($/MMBtu)	Ammonia (SCR) ($/MMBtu)	(DFGD) ($/MMBtu)	VOM ($/Mwh)	*If U2 NOT* Returned	*If U2 Returned* Dec-19	*If U2 Returned* Dec-22	*If U2 NOT* Returned	*If U2 Returned* Dec-19	*If U2 Returned* Dec-22
2016	1,315	500	[redacted]										1.01	9,005	9,005	9,005	26,627	26,627	26,627
2017	1,315	500	[redacted]										1.03	17,022	17,022	17,022	34,572	34,572	34,572
2018 RK1 SCR	1,351	651	[redacted]										1.05	9,648	9,648	9,648	15,192	15,192	15,192
2019	1,351	651	[redacted]										1.07	9,154	9,154	9,154	34,128	34,128	34,128
2020	1,351	651	[redacted]										1.08	18,291	25,589	18,291	49,829	76,708	49,829
2021	1,351	651	[redacted]										1.10	9,480	16,898	9,480	38,508	53,181	38,508
2022	1,351	651	[redacted]										1.12	16,828	24,391	16,828	17,530	23,234	17,530
2023	1,351	651	[redacted]										1.14	10,055	17,749	17,749	7,244	10,408	10,408
2024	1,351	651	[redacted]										1.17	17,958	25,791	25,791	5,779	8,895	8,895
2025	1,351	651	[redacted]										1.19	9,643	17,171	17,171	2,104	2,963	2,963
2026 RK1 DFGD	1,333	651	[redacted]										1.21	12,374	20,416	20,416	24,520	24,520	24,520
2027	1,333	651	[redacted]										1.24	11,516	19,683	19,683	25,133	25,133	25,133
2028	1,333	651	[redacted]										1.26	12,840	21,132	21,132	25,761	25,761	25,761
2029	1,333	651	[redacted]										1.28	11,144	19,557	19,557	26,405	26,405	26,405
2030	1,333	651	[redacted]										1.31	12,908	21,553	21,553	27,065	27,065	27,065
2031	1,333	651	[redacted]										1.33	12,648	21,452	21,452	27,742	27,742	27,742
2032	1,333	651	[redacted]										1.36	12,228	21,198	21,198	28,435	28,435	28,435
2033	1,333	651	[redacted]										1.38	13,817	22,966	22,966	29,146	29,146	29,146
2034	1,333	651	[redacted]										1.41	12,787	22,129	22,129	29,875	29,875	29,875
2035	1,333	651	[redacted]										1.43	13,665	23,190	23,190	30,622	30,622	30,622
2036	1,333	651	[redacted]										1.46	13,285	23,000	23,000	31,387	31,387	31,387
2037	1,333	651	[redacted]										1.48	15,193	25,103	25,103	32,172	32,172	32,172
2038	1,333	651	[redacted]										1.51	13,733	23,843	23,843	32,976	32,976	32,976
2039	1,333	651	[redacted]										1.54	14,977	25,289	25,289	33,801	33,801	33,801
2040	1,333	651	[redacted]										1.56	14,531	25,050	25,050	32,111	32,111	32,111
2041	1,333	651	[redacted]										1.59	15,781	26,511	26,511	30,505	30,505	30,505
2042	1,333	651	[redacted]										1.62	14,803	25,748	25,748	28,980	28,980	28,980
2043	1,333	651	[redacted]										1.64	16,373	27,537	27,537	27,531	27,531	27,531
2044	1,333	651	[redacted]										1.67	15,706	27,095	27,095	26,154	26,154	26,154
2045	1,333	651	[redacted]										1.70	17,727	29,344	29,344	24,847	24,847	24,847

Rockport Unit 2...

	Rockport U2 (Total Unit -- initially, 1300 MW)													Rockport U2 (I&M Cost-Based Share [@85%])					
	Performance Parameter							Cost Parameter											
									Consumables					($000)					
	Unit Capability		Heat Rate	Avg.	Emission Rates			Delivered	Sodium	Activated	Anhydrous	Lime	Other	FOM			On-Going Capital*		
	Max (MW)	Min (MW)	-Avg Annual- (Btu/kWh)	Availability (%)	SO_2 (lb./MMBtu)	NO_x (lb./MMBtu)	Hg (lb/Trillion Btu)	Fuel Cost ($/MMBtu)	Bicarb (DSI) ($/MMBtu)	Carbon (ACI) ($/MMBtu)	Ammonia (SCR) ($/MMBtu)	(DFGD) ($/MMBtu)	VOM ($/Mwh)	*If U2 NOT* Returned	*If U2 Returned* Dec-19	*If U2 Returned* Dec-22	*If U2 NOT* Returned	*If U2 Returned* Dec-19	*If U2 Returned* Dec-22
2016	1,300	500	[redacted]										0.99	9,118	9,118	9,118	6,384	4,788	6,384
2017	1,300	500	[redacted]										1.01	9,101	9,101	9,101	12,036	3,975	5,963
2018	1,300	651	[redacted]										1.03	18,609	18,609	18,609	35,417	5,371	10,743
2019	1,300	651	[redacted]										1.04	18,665	18,665	18,665	46,295	0	9,400
2020 RK2 SCR	1,336	651	[redacted]										1.06	10,202	-	10,202	27,872	-	2,787
2021	1,336	651	[redacted]										1.08	17,605	-	17,605	22,943	-	2,294
2022	1,336	651	[redacted]										1.10	10,989	-	10,989	29,987	-	0
2023	1,336	651	[redacted]										1.12	18,109	-	-	58,104	-	-
2024	1,336	651	[redacted]										1.14	11,114	-	-	9,309	-	-
2025	1,336	651	[redacted]										1.16	7,852	-	-	10,534	-	-
2026	1,336	651	[redacted]										1.19	10,792	-	-	24,520	-	-
2027	1,336	651	[redacted]										1.21	11,384	-	-	25,133	-	-
2028	1,336	651	[redacted]										1.23	12,217	-	-	25,761	-	-
2029 RK2 DFGD	1,318	651	[redacted]										1.25	10,069	-	-	26,405	-	-
2030	1,318	651	[redacted]										1.28	11,409	-	-	27,065	-	-
2031	1,318	651	[redacted]										1.30	11,139	-	-	27,742	-	-
2032	1,318	651	[redacted]										1.33	11,815	-	-	28,435	-	-
2033	1,318	651	[redacted]										1.35	11,029	-	-	29,146	-	-
2034	1,318	651	[redacted]										1.38	12,095	-	-	29,875	-	-
2035	1,318	651	[redacted]										1.40	11,711	-	-	30,622	-	-
2036	1,318	651	[redacted]										1.43	12,823	-	-	31,387	-	-
2037	1,318	651	[redacted]										1.45	12,044	-	-	32,172	-	-
2038	1,318	651	[redacted]										1.48	13,523	-	-	32,976	-	-
2039	1,318	651	[redacted]										1.50	12,513	-	-	33,801	-	-
2040	1,318	651	[redacted]										1.53	13,566	-	-	32,111	-	-
2041	1,318	651	[redacted]										1.55	12,932	-	-	30,505	-	-
2042	1,318	651	[redacted]										1.58	14,529	-	-	28,980	-	-
2043	1,318	651	[redacted]										1.61	13,652	-	-	27,531	-	-
2044	1,318	651	[redacted]										1.64	14,971	-	-	26,154	-	-
2045	1,318	651	[redacted]										1.66	13,926	-	-	24,847	-	-

* Rockport unit 'On-Going Capital (OGC)' excludes both U1 & U2 SCR and (future) U1 & U2 DFGD major environmental capital expenditures highlighted on Weaver Direct Testimony, 'Table 3'

Indiana Michigan Power Company
Attachment SCW-3
Page 2 of 2
PUBLIC

Summary of Major Cost & Performance Paramenters Used in Modeling
(All Cost Estimates reflected in 'Nominal' $)

New-Build Natural Gas Alternatives...

New-Build CC ("1/2 Block" of a 780 MW [870 MW w/ evap cooling], Mitsubishi 501GAC 2x2x1)

Available In-Svc Years	Capability* Max(Sum) (w/ Evap Cooling) (MW)	Capability* Nominal (MW)	Capability* Min (MW)	Avg. Avail. (%)	(Nominal) Heat Rate -Avg Annual- (Btu/kWh)	Fuel Cost @ 'TCO Pool' ** ($/MMBtu)	VOM ($/Mwh)	FOM ($/kW-Yr)	On-Going Capital*** ($/kW-Yr)
2016	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-
2020 Opt 2	435	390	95	[redacted]			$ 3.09	$ 12.32	-
2021	435	390	95				$ 3.15	$ 12.57	-
2022	435	390	95				$ 3.22	$ 12.82	-
2023 Opt 1B	435	390	95				$ 3.28	$ 13.08	-
2024	435	390	95				$ 3.35	$ 13.34	-
2025	435	390	95				$ 3.41	$ 13.60	-
2026	435	390	95				$ 3.48	$ 13.88	-
2027	435	390	95				$ 3.55	$ 14.15	-
2028	435	390	95				$ 3.62	$ 14.44	-
2029	435	390	95				$ 3.69	$ 14.73	-
2030	435	390	95				$ 3.77	$ 15.02	-
2031	435	390	95				$ 3.84	$ 15.32	-
2032	435	390	95				$ 3.92	$ 15.63	-
2033	435	390	95				$ 4.00	$ 15.94	-
2034	435	390	95				$ 4.08	$ 16.26	-
2035	435	390	95				$ 4.16	$ 16.58	-
2036	435	390	95				$ 4.24	$ 16.91	-
2037	435	390	95				$ 4.33	$ 17.25	-
2038	435	390	95				$ 4.42	$ 17.60	-
2039	435	390	95				$ 4.50	$ 17.95	-
2040	435	390	95				$ 4.59	$ 18.31	-
2041	435	390	95				$ 4.69	$ 18.68	-
2042	435	390	95				$ 4.78	$ 19.05	-
2043	435	390	95				$ 4.88	$ 19.43	-
2044	435	390	95				$ 4.97	$ 19.82	-
2045	435	390	95				$ 5.07	$ 20.21	-

New-Build SC-CT (430 MW, 2X GE 7FA.05)

Years	Capability (Per 2X 'Block') Max(Sum) (MW)	Capability (Per 2X 'Block') Min (MW)	Heat Rate -Avg Annual- (Btu/kWh)	Avg. Availability (%)	Fuel Cost @ 'TCO Pool' ** ($/MMBtu)	VOM ($/Mwh)	FOM ($/kW-Yr)	On-Going Capital*** ($/kW-Yr)
2016	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-
2020 Opt 2	431	95	[redacted]			$ 1.59	$ 9.78	-
2021	431	95				$ 1.62	$ 9.98	-
2022	431	95				$ 1.65	$ 10.18	-
2023 Opt 1B	431	95				$ 1.69	$ 10.38	-
2024	431	95				$ 1.72	$ 10.59	-
2025	431	95				$ 1.76	$ 10.80	-
2026	431	95				$ 1.79	$ 11.02	-
2027	431	95				$ 1.83	$ 11.24	-
2028	431	95				$ 1.86	$ 11.46	-
2029	431	95				$ 1.90	$ 11.69	-
2030	431	95				$ 1.94	$ 11.92	-
2031	431	95				$ 1.98	$ 12.16	-
2032	431	95				$ 2.02	$ 12.41	-
2033	431	95				$ 2.06	$ 12.65	-
2034	431	95				$ 2.10	$ 12.91	-
2035	431	95				$ 2.14	$ 13.17	-
2036	431	95				$ 2.18	$ 13.43	-
2037	431	95				$ 2.23	$ 13.70	-
2038	431	95				$ 2.27	$ 13.97	-
2039	431	95				$ 2.32	$ 14.25	-
2040	431	95				$ 2.36	$ 14.54	-
2041	431	95				$ 2.41	$ 14.83	-
2042	431	95				$ 2.46	$ 15.12	-
2043	431	95				$ 2.51	$ 15.43	-
2044	431	95				$ 2.56	$ 15.73	-
2045	431	95				$ 2.61	$ 16.05	-

New-Build SC-CT (Small Frame: 189 MW, 2X GE 7FA.05)

Years	Capability (Per 2X 'Block') Max(Sum) (MW)	Capability (Per 2X 'Block') Min (MW)	Heat Rate -Avg Annual- (Btu/kWh)	Avg. Availability (%)	Fuel Cost @ 'TCO Pool' ** ($/MMBtu)	VOM ($/Mwh)	FOM ($/kW-Yr)	On-Going Capital*** ($/kW-Yr)
2016	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-
2020 Opt 2	179	84	[redacted]			$ 1.59	$ 15.67	-
2021	179	84				$ 1.62	$ 15.98	-
2022	179	84				$ 1.65	$ 16.30	-
2023 Opt 1B	179	84				$ 1.69	$ 16.63	-
2024	179	84				$ 1.72	$ 16.96	-
2025	179	84				$ 1.76	$ 17.30	-
2026	179	84				$ 1.79	$ 17.64	-
2027	179	84				$ 1.83	$ 18.00	-
2028	179	84				$ 1.86	$ 18.36	-
2029	179	84				$ 1.90	$ 18.72	-
2030	179	84				$ 1.94	$ 19.10	-
2031	179	84				$ 1.98	$ 19.48	-
2032	179	84				$ 2.02	$ 19.87	-
2033	179	84				$ 2.06	$ 20.27	-
2034	179	84				$ 2.10	$ 20.67	-
2035	179	84				$ 2.14	$ 21.09	-
2036	179	84				$ 2.18	$ 21.51	-
2037	179	84				$ 2.23	$ 21.94	-
2038	179	84				$ 2.27	$ 22.38	-
2039	179	84				$ 2.32	$ 22.82	-
2040	179	84				$ 2.36	$ 23.28	-
2041	179	84				$ 2.41	$ 23.75	-
2042	179	84				$ 2.46	$ 24.22	-
2043	179	84				$ 2.51	$ 24.71	-
2044	179	84				$ 2.56	$ 25.20	-
2045	179	84				$ 2.61	$ 25.70	-

New-Build Aeroderivative (87 MW, 2X GE-LM600 Sprint)

Years	Capability (Per 2X 'Block') Max(Sum) (MW)	Capability (Per 2X 'Block') Min (MW)	Heat Rate -Avg Annual- (Btu/kWh)	Fuel Cost @ 'TCO Pool' ** ($/MMBtu)	VOM ($/Mwh)	FOM ($/kW-Yr)	On-Going Capital*** ($/kW-Yr)
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-
2020 Opt 2	87	44	[redacted]		$ 3.64	$ 13.54	-
2021	87	44			$ 3.72	$ 13.81	-
2022	87	44			$ 3.79	$ 14.08	-
2023 Opt 1B	87	44			$ 3.87	$ 14.36	-
2024	87	44			$ 3.94	$ 14.65	-
2025	87	44			$ 4.02	$ 14.94	-
2026	87	44			$ 4.10	$ 15.24	-
2027	87	44			$ 4.19	$ 15.55	-
2028	87	44			$ 4.27	$ 15.86	-
2029	87	44			$ 4.35	$ 16.18	-
2030	87	44			$ 4.44	$ 16.50	-
2031	87	44			$ 4.53	$ 16.83	-
2032	87	44			$ 4.62	$ 17.17	-
2033	87	44			$ 4.71	$ 17.51	-
2034	87	44			$ 4.81	$ 17.86	-
2035	87	44			$ 4.90	$ 18.22	-
2036	87	44			$ 5.00	$ 18.58	-
2037	87	44			$ 5.10	$ 18.95	-
2038	87	44			$ 5.20	$ 19.33	-
2039	87	44			$ 5.31	$ 19.72	-
2040	87	44			$ 5.41	$ 20.11	-
2041	87	44			$ 5.52	$ 20.52	-
2042	87	44			$ 5.63	$ 20.93	-
2043	87	44			$ 5.75	$ 21.34	-
2044	87	44			$ 5.86	$ 21.77	-
2045	87	44			$ 5.98	$ 22.21	-

New-Build CHP (15 MW, GE-LM600 Sprint w/ Steam Host)

Years	Capability (Per 2X 'Block') Max(Sum) (MW)	Capability (Per 2X 'Block') Min (MW)	Heat Rate -Avg Annual- (Btu/kWh)	Fuel Cost @ 'TCO Pool' ** ($/MMBtu)	VOM ($/Mwh)	FOM ($/kW-Yr)	On-Going Capital*** ($/kW-Yr)
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-
2020 Opt 2	15	7	[redacted]		$ 1.44	$ 54.43	-
2021	15	7			$ 1.46	$ 55.52	-
2022	15	7			$ 1.49	$ 56.63	-
2023 Opt 1B	15	7			$ 1.53	$ 57.76	-
2024	15	7			$ 1.55	$ 58.91	-
2025	15	7			$ 1.59	$ 60.09	-
2026	15	7			$ 1.62	$ 61.29	-
2027	15	7			$ 1.65	$ 62.52	-
2028	15	7			$ 1.68	$ 63.77	-
2029	15	7			$ 1.72	$ 65.05	-
2030	15	7			$ 1.75	$ 66.35	-
2031	15	7			$ 1.79	$ 67.67	-
2032	15	7			$ 1.82	$ 69.03	-
2033	15	7			$ 1.86	$ 70.41	-
2034	15	7			$ 1.90	$ 71.82	-
2035	15	7			$ 1.93	$ 73.25	-
2036	15	7			$ 1.97	$ 74.72	-
2037	15	7			$ 2.01	$ 76.21	-
2038	15	7			$ 2.05	$ 77.74	-
2039	15	7			$ 2.09	$ 79.29	-
2040	15	7			$ 2.13	$ 80.88	-
2041	15	7			$ 2.18	$ 82.49	-
2042	15	7			$ 2.22	$ 84.14	-
2043	15	7			$ 2.27	$ 85.83	-
2044	15	7			$ 2.31	$ 87.54	-
2045	15	7			$ 2.36	$ 89.29	-

* As a practical matter, due to poorer thermal efficiency/heat rate, evaporator cooling would be limited during higher temperature periods. Therefore, for dispatch (energy) modeling purposes, a slightly lower 'nominal' rating --and (lower/improved) attendant Heat Rate-- was utilized throughout the forecast period... However, Max(Sum) "with evaporating-cooling" Capability *was* recognized for purposes of determination of attributable PJM (summer) unforced capability (UCAP) value.
** Per 'BASE' pricing scenario, inclusive of Swing Service Adder.
*** 'On-Going Capital' expenditures are assumed to be incorporated into the Fixed O&M (FOM) estimates shown.

Indiana Michigan Power Company
Attachment SCW-4-1

Indiana Michigan Power Co.
Rockport Unit 2 Disposition Analysis
Long-Term, Life Cycle Economics (2016-2045, with end-effects)

COMPARATIVE **Cumulative Present Worth (CPW) of I&M Net Utility "Generation" Costs (2016 $)**
(COST / <SAVINGS>)

$ Millions	Option #1B: RETROFIT RK2 w/ SCR (12/2019); then RETURN (to Lessor) at 12/2022 Lease Termination & REPLACE RKU2 w/ New-Build Resources (1/2023) *over*	Option #2: NO RK2 SCR... RETURN (to Lessor) at 12/2019 Early Termination & REPLACE RK U2 w/ New-Build Resources (1/2020) *over*
	Option #1A — RETROFIT Rockport Unit 2 with SCR (12/2019) then --*for modeling purposes only* -- assume NPDES/ELG/CCR-related equipment installed (total Plant) by 2019-2021, and **RKU2 DFGD and associated equipment installed by 12/2028**	
L/T Commodity Pricing Scenarios		
"BASE" Forecast	84	322
Alternative Scenario Pricing...		
"Lower Band"	(131)	99
"Higher Band"	349	621
"No Carbon"	233	485
"High Carbon"	(90)	142

Notes:
- o All scenario pricing alternatives (excluding "No CO_2") assume carbon/CO_2 pricing is effective in 2022
- o Option #1A (RK U2 w/ SCR & DFGD) assumes investment recovery period for SCR (beg. 2020), and DFGD (beg. 2029), of 10 and 20-years, respectively
- o Option #1B (RK U2 w/ SCR [only]) assumes investment recovery period for SCR (beg. 2020) of 10-years
- o Option #2 (RK U2 No SCR Return to Lessor 12/2019) assumes a 30-year recovery period for any replacment resources (CC and/or CTs, AD, CHP) in all analyses
- o Each Rockport unit reflects I&M's 50% (650-MW) Ownership share; plus 70% (455-MW) Purch.Entitlement from affiliate AEP Generating Cos.'

Indiana Michigan Power Company
Attachment SCW-4-2

Indiana Michigan Power Co.
Rockport Unit 2 Disposition Analysis
Long-Term, Life Cycle Economics (2016-2045, with end-effects)

COMPARATIVE **Cumulative Present Worth (CPW) of I&M Net Utility "Generation" Costs (2016 $)**
(COST / <SAVINGS>)

$ Millions	Option #1A: RETROFIT RK2 w/ SCR (12/2019) then --*for modeling purposes only*-- install NPDES/ELG/CCR-related equiment in 2019-2021, then RKU2 DFGD by 12/2028	Option #2: NO RK2 SCR... RETURN (to Lessor) at 12/2019 Early Termination & REPLACE RK U2 w/ New-Build Resources (1/2020)
	over	*over*
	Option #1B: RETROFIT Rockport Unit 2 with SCR (12/2019) then RETURN (to Lessor) at 12/2022 Lease Termination & REPLACE RKU2 w/ New-Build Resources (1/2023)	
L/T Commodity Pricing Scenarios		
"BASE" Forecast	(84)	239
Alternative Scenario Pricing...		
"Lower Band"	131	230
"Higher Band"	(349)	272
"No Carbon"	(233)	252
"High Carbon"	90	233

Notes:
- o All scenario pricing alternatives (excluding "No CO_2") assume carbon/CO_2 pricing is effective in 2022
- o Option #1A (RK U2 w/ SCR & DFGD) assumes investment recovery period for SCR (beg. 2020), and DFGD (beg. 2029), of 10 and 20-years, respectively
- o Option #1B (RK U2 w/ SCR [only]) assumes investment recovery period for SCR (beg. 2020) of 10-years
- o Option #2 (RK U2 No SCR Return to Lessor 12/2019) assumes a 30-year recovery period for any replacment resources (CC and/or CTs, AD, CHP) in all analyses
- o Each Rockport unit reflects I&M's 50% (650-MW) Ownership share; plus 70% (455-MW) Purch.Entitlement from affiliate AEP Generating Cos.' 50% ownership share

INDIANA MICHIGAN POWER COMPANY

Rockport Unit 2 Disposition Analysis

"BASE" Long-term Commodity Pricing Forecast

	CPW ($000)			*CPW Cost/ <Savings> Over 'Option **1A**'*			*CPW Cost/ <Savings> Over 'Option **1B**'*		
Disposition Alternative [1]	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period
Rockport 2 SCR:									
Option 1A [2]	12,579,284	3,573,614	16,152,898	-	-	-	84,431	(168,061)	***(83,630)***
Option 1B [3]	12,494,853	3,741,675	16,236,528	(84,431)	168,061	***83,630***	-	-	-
No Rockport 2 SCR:									
Option 2 [4]	12,748,173	3,727,194	16,475,367	168,889	153,580	***322,469***	253,320	(14,482)	***238,839***
(SENSITIVITY) **Option 2A** [5]	12,755,098	3,743,742	16,498,840	175,814	170,128	***345,942***	260,246	2,067	***262,312***

Note:

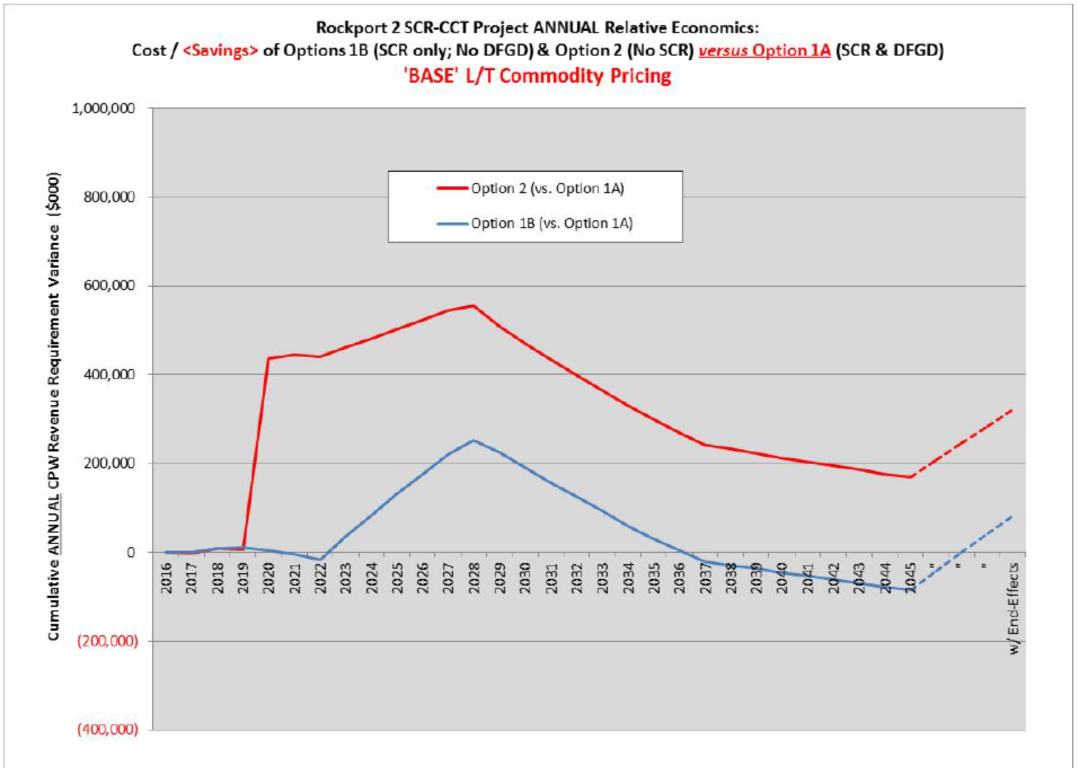
(1) All cases assume Rockport Unit 1 SCR installation by 12/31/2017, and DFGD installation by 12/31/2025

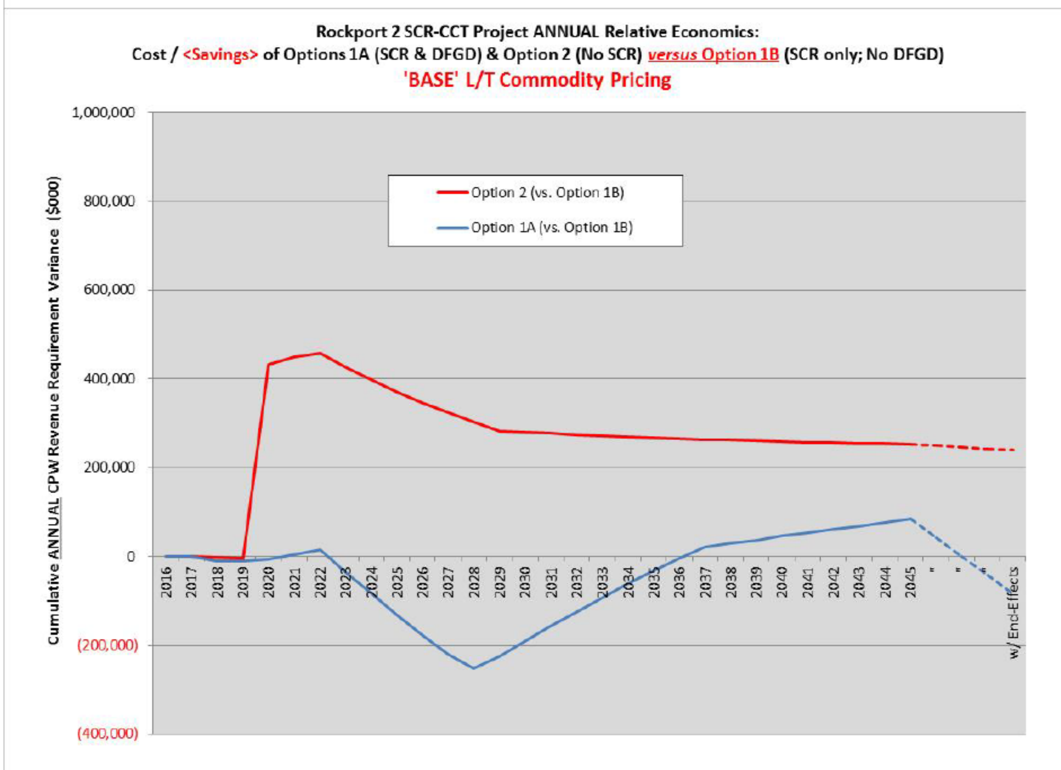
(2) Option 1A assumes Rockport Unit 2 SCR installation by 12/31/2019 and DFGD installation by 12/31/2028

(3) Option 1B assumes Rockport Unit 2 SCR installation by 12/31/2019, but No DFGD installation...
returning the unit to the Lessor by 12/31/2022 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2023

(4) Option 2 assumes No Rockport Unit 2 SCR installation by 12/31/2019... terminating the operating lease and
returning the unit to the Lessor by 12/31/2019 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2020

(5) *same as 'Option 2' except assume any replacement CC capacity would be delayed until 1/1/2023 (relying on the PJM capacity & energy market in the interim)*


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1B (SCR only; No DFGD) & Option 2 (No SCR) versus Option 1A (SCR & DFGD)
'BASE' L/T Commodity Pricing
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
Option 2 (vs. Option 1A)
Option 1B (vs. Option 1A)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
w/ End-Effects


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1A (SCR & DFGD) & Option 2 (No SCR) versus Option 1B (SCR only; No DFGD)
'BASE' L/T Commodity Pricing
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
Option 2 (vs. Option 1B)
Option 1A (vs. Option 1B)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
w/ End-Effects

INDIANA MICHIGAN POWER COMPANY

Rockport Unit 2 Disposition Analysis

"Lower Band" Long-term Commodity Pricing Forecast

	CPW ($000)			*CPW Cost/ <Savings> Over 'Option 1A'*			*CPW Cost/ <Savings> Over 'Option 1B'*		
Disposition Alternative [1]	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period
Rockport 2 SCR:									
Option 1A [2]	12,705,895	3,455,205	16,161,100	-	-	-	232,324	(101,302)	***131,022***
Option 1B [3]	12,473,571	3,556,507	16,030,078	(232,324)	101,302	***(131,022)***	-	-	-
No Rockport 2 SCR:									
Option 2 [4]	12,717,690	3,542,025	16,259,716	11,795	86,820	***98,615***	244,119	(14,482)	***229,637***
(SENSITIVITY) **Option 2A** [5]	12,710,770	3,558,574	16,269,344	4,875	103,369	***108,244***	237,199	2,067	***239,266***

Note:

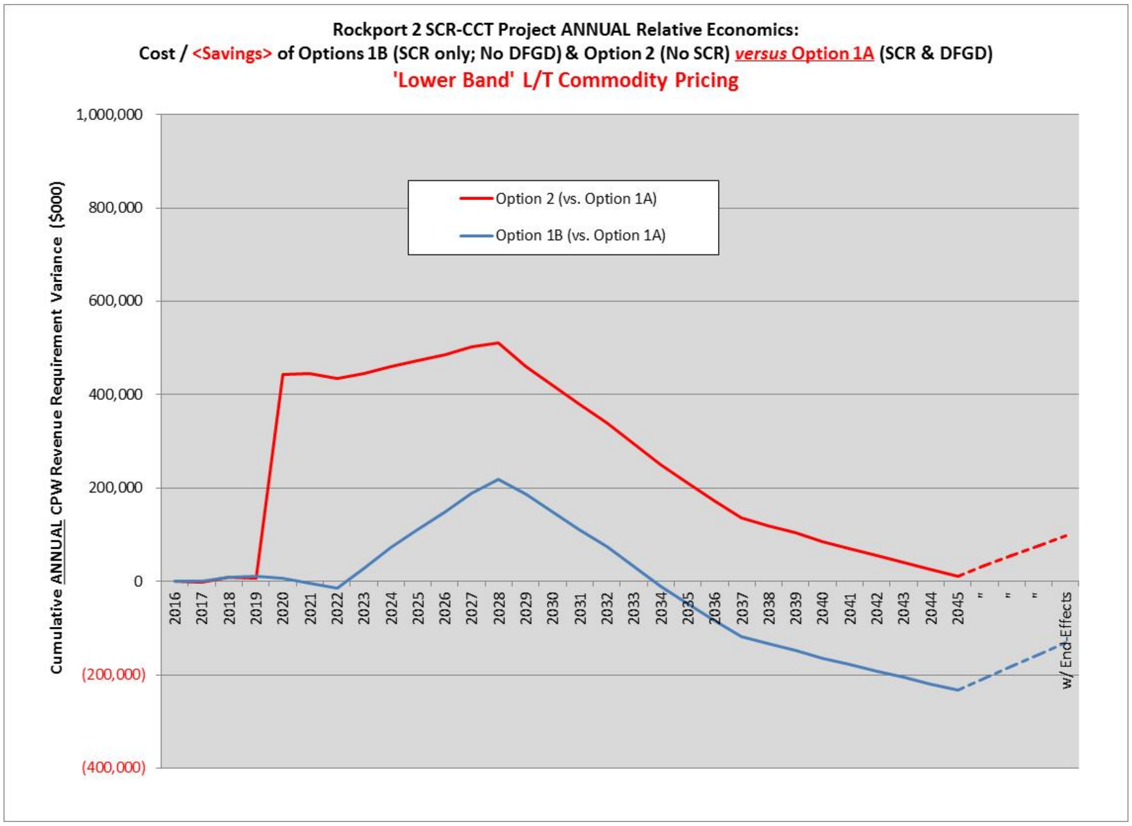
(1) All cases assume Rockport Unit 1 SCR installation by 12/31/2017, and DFGD installation by 12/31/2025

(2) Option 1A assumes Rockport Unit 2 SCR installation by 12/31/2019 and DFGD installation by 12/31/2028

(3) Option 1B assumes Rockport Unit 2 SCR installation by 12/31/2019, but No DFGD installation... returning the unit to the Lessor by 12/31/2022 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2023

(4) Option 2 assumes No Rockport Unit 2 SCR installation by 12/31/2019... terminating the operating lease and returning the unit to the Lessor by 12/31/2019 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2020

(5) *same as 'Option 2' except assume any replacement CC capacity would be delayed until 1/1/2023 (relying on the PJM capacity & energy market in the interim)*


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1B (SCR only; No DFGD) & Option 2 (No SCR) versus Option 1A (SCR & DFGD)
'Lower Band' L/T Commodity Pricing
Option 2 (vs. Option 1A)
Option 1B (vs. Option 1A)
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
2016
2017
2018
2019
2020
2021
2022
2023
2024
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2026
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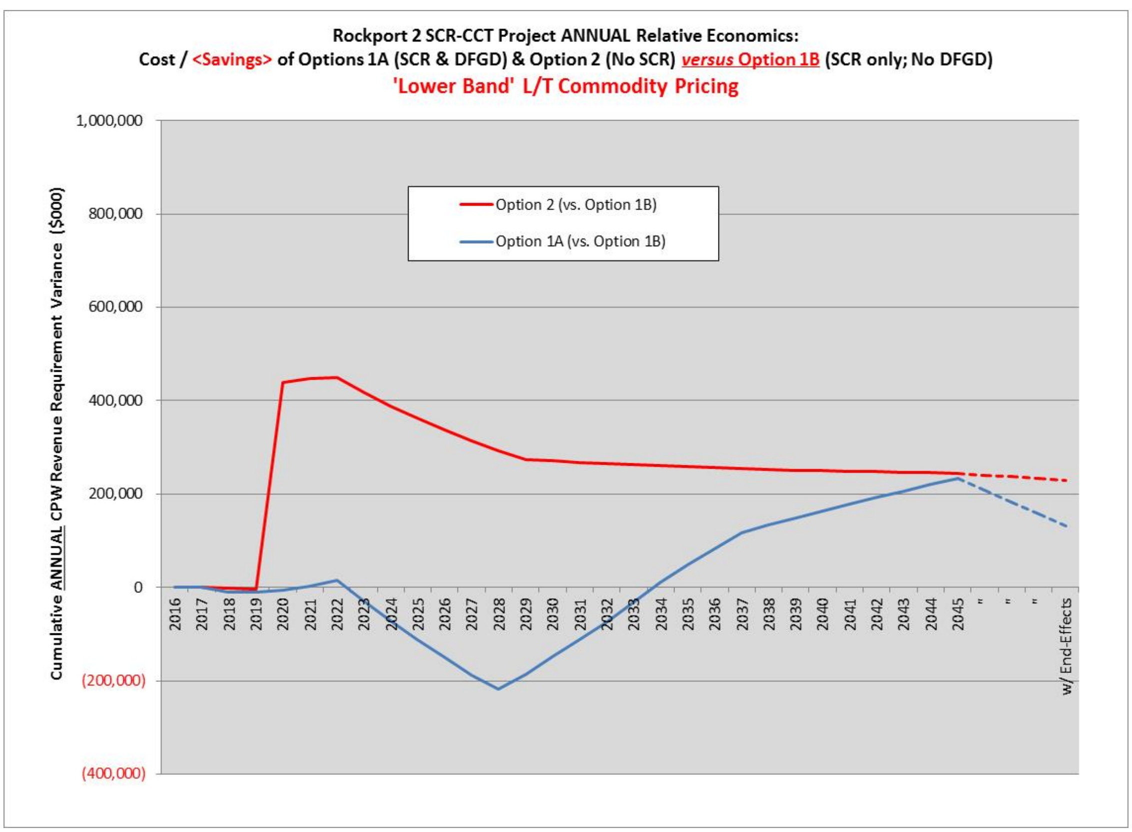
2043
2044
2045
w/ End-Effects


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1A (SCR & DFGD) & Option 2 (No SCR) versus Option 1B (SCR only; No DFGD)
'Lower Band' L/T Commodity Pricing
Option 2 (vs. Option 1B)
Option 1A (vs. Option 1B)
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
2016
2017
2018
2019
2020
2021
2022
2023
2024
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2040
2041
2042
2043
2044
2045
w/ End-Effects

INDIANA MICHIGAN POWER COMPANY

Rockport Unit 2 Disposition Analysis

"Higher Band" Long-term Commodity Pricing Forecast

	CPW ($000)			*CPW Cost/ <Savings> Over 'Option 1A'*			*CPW Cost/ <Savings> Over 'Option 1B'*		
Disposition Alternative [1]	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period
Rockport 2 SCR:									
Option 1A [2]	12,618,732	3,629,861	16,248,593	-	-	-	(20,041)	(328,818)	***(348,858)***
Option 1B [3]	12,638,773	3,958,679	16,597,452	20,041	328,818	***348,858***	-	-	-
No Rockport 2 SCR:									
Option 2 [4]	12,925,508	3,944,197	16,869,705	306,776	314,336	***621,112***	286,735	(14,482)	***272,254***
(SENSITIVITY) **Option 2A** [5]	12,901,401	3,960,746	16,862,147	282,669	330,885	***613,554***	262,629	2,067	***264,695***

Note:

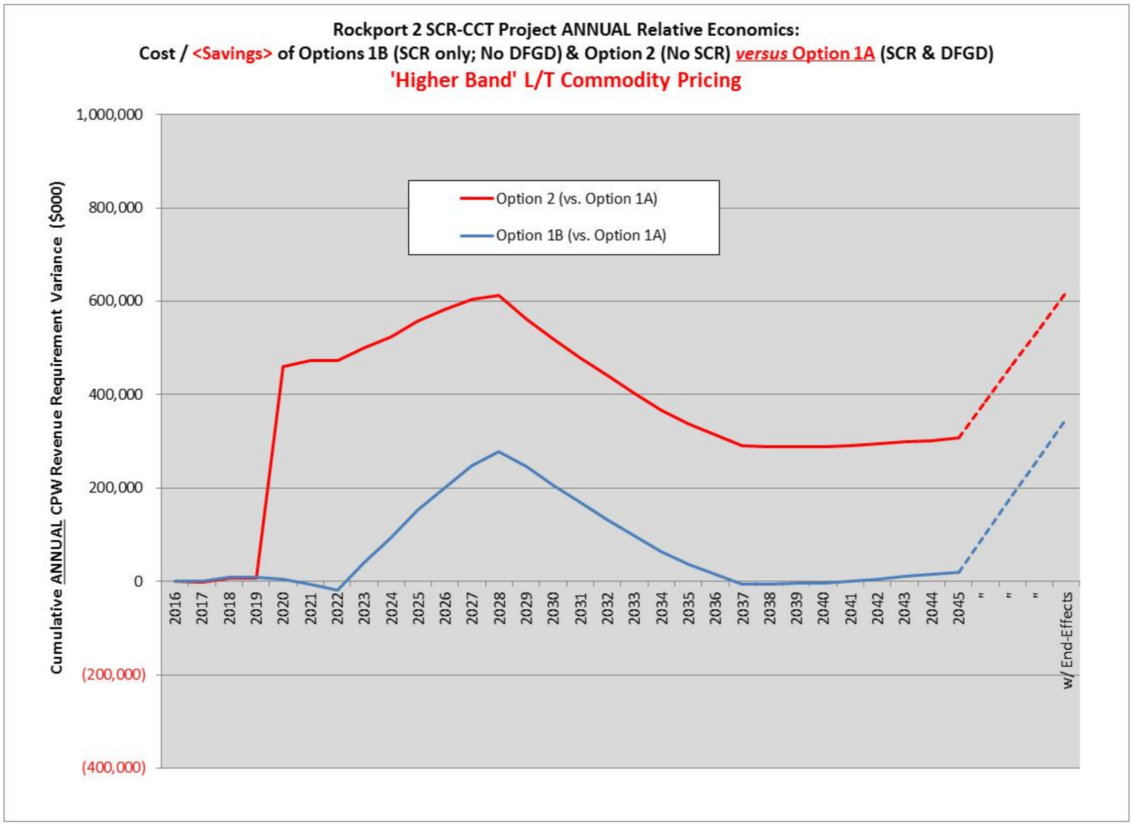
(1) All cases assume Rockport Unit 1 SCR installation by 12/31/2017, and DFGD installation by 12/31/2025

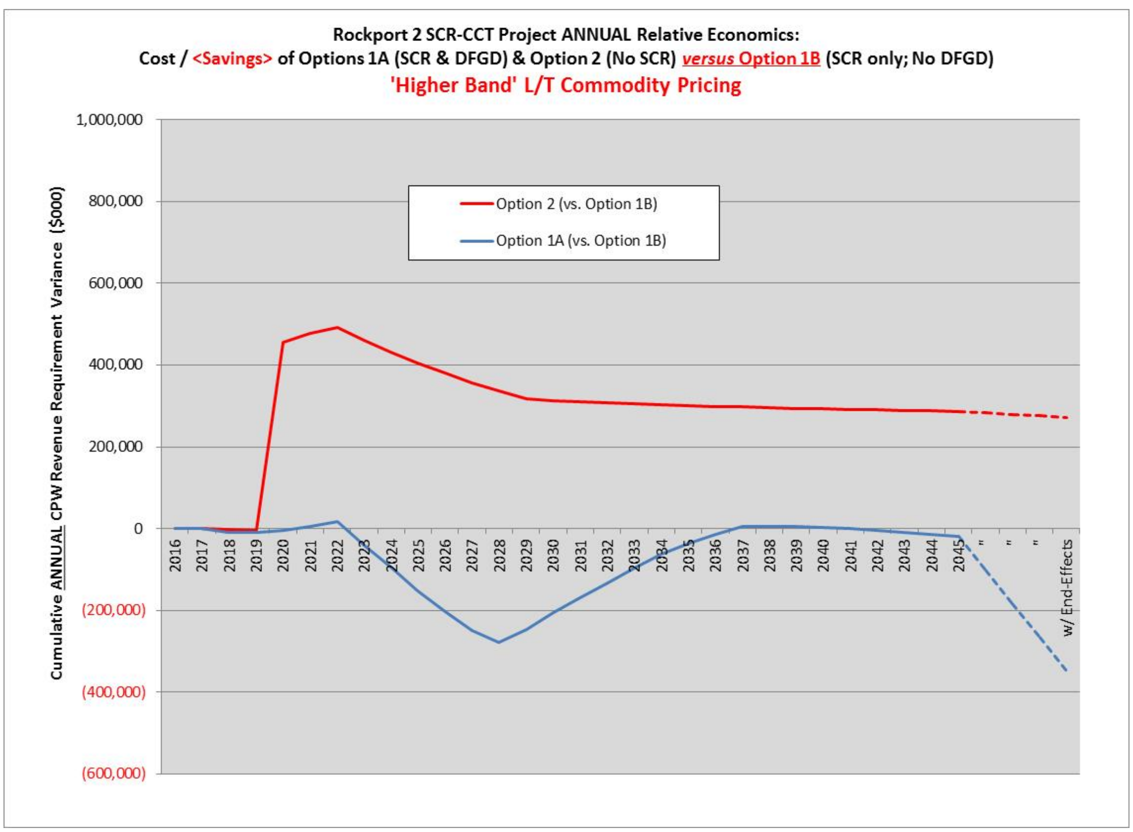
(2) Option 1A assumes Rockport Unit 2 SCR installation by 12/31/2019 and DFGD installation by 12/31/2028

(3) Option 1B assumes Rockport Unit 2 SCR installation by 12/31/2019, but No DFGD installation... returning the unit to the Lessor by 12/31/2022 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2023

(4) Option 2 assumes No Rockport Unit 2 SCR installation by 12/31/2019... terminating the operating lease and returning the unit to the Lessor by 12/31/2019 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2020

(5) *same as 'Option 2' except assume any replacement CC capacity would be delayed until 1/1/2023 (relying on the PJM capacity & energy market in the interim)*


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1B (SCR only; No DFGD) & Option 2 (No SCR) versus Option 1A (SCR & DFGD)
'Higher Band' L/T Commodity Pricing
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
Option 2 (vs. Option 1A)
Option 1B (vs. Option 1A)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
w/ End-Effects


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1A (SCR & DFGD) & Option 2 (No SCR) versus Option 1B (SCR only; No DFGD)
'Higher Band' L/T Commodity Pricing
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
(600,000)
Option 2 (vs. Option 1B)
Option 1A (vs. Option 1B)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
w/ End-Effects

INDIANA MICHIGAN POWER COMPANY

Rockport Unit 2 Disposition Analysis

"No Carbon" Long-term Commodity Pricing Forecast

	CPW ($000)			*CPW Cost/ <Savings> Over 'Option 1A'*			*CPW Cost/ <Savings> Over 'Option 1B'*		
Disposition Alternative [1]	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period
Rockport 2 SCR:									
Option 1A [2]	11,940,832	3,165,463	15,106,295	-	-	-	(74,882)	(157,709)	***(232,591)***
Option 1B [3]	12,015,714	3,323,172	15,338,886	74,882	157,709	***232,591***	-	-	-
No Rockport 2 SCR:									
Option 2 [4]	12,282,405	3,308,690	15,591,096	341,573	143,228	***484,801***	266,691	(14,482)	***252,209***
(SENSITIVITY) **Option 2A** [5]	12,252,452	3,325,239	15,577,691	311,619	159,776	***471,395***	236,738	2,067	***238,804***

Note:

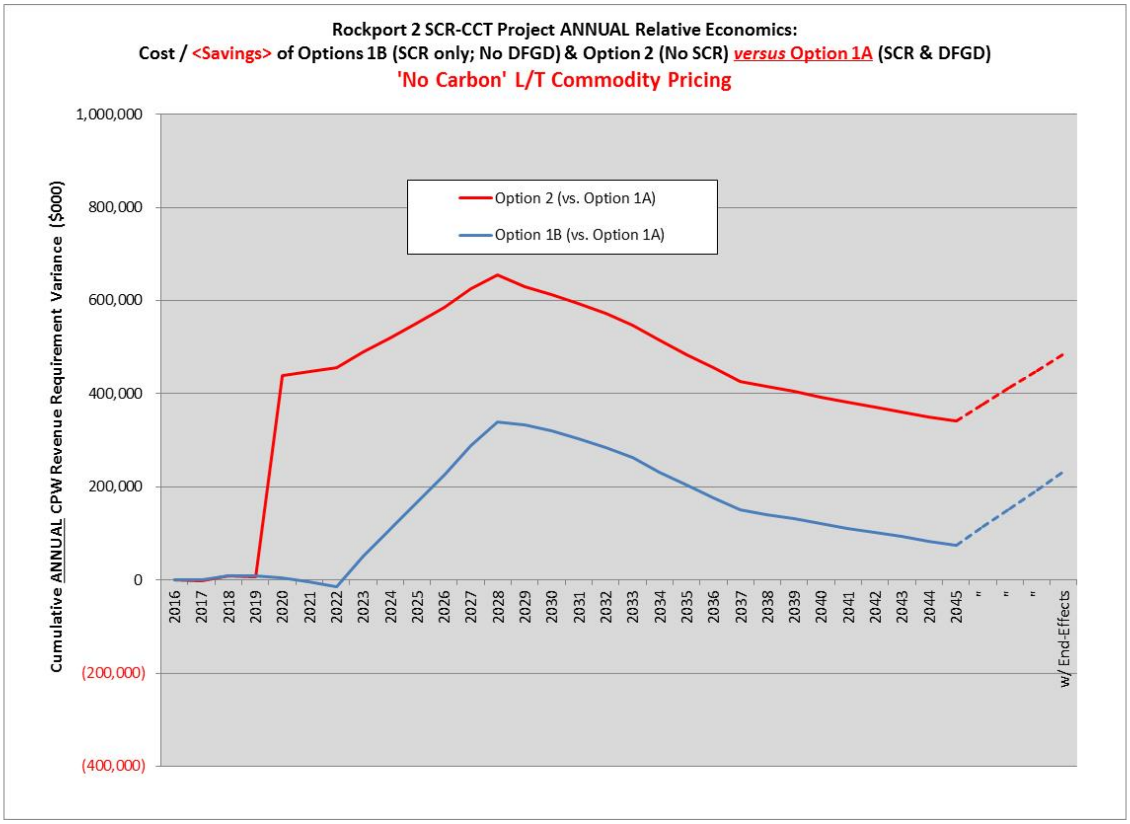
(1) All cases assume Rockport Unit 1 SCR installation by 12/31/2017, and DFGD installation by 12/31/2025

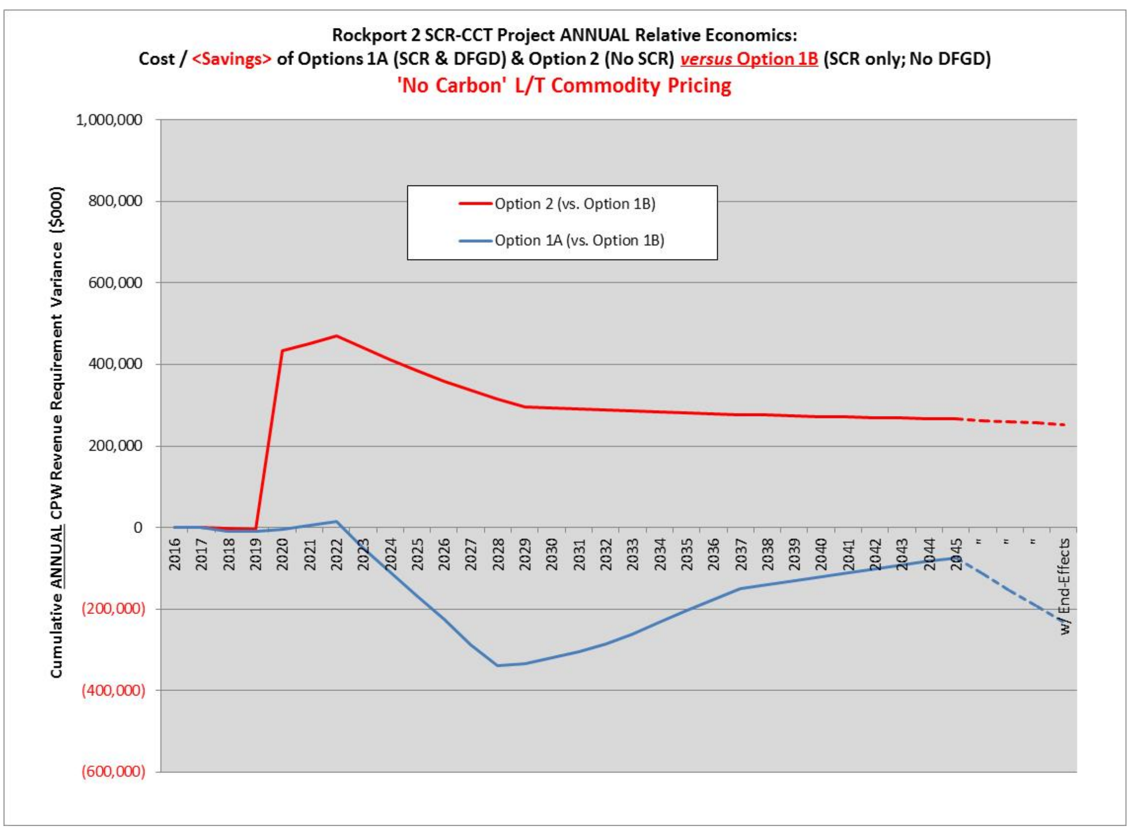
(2) Option 1A assumes Rockport Unit 2 SCR installation by 12/31/2019 and DFGD installation by 12/31/2028

(3) Option 1B assumes Rockport Unit 2 SCR installation by 12/31/2019, but No DFGD installation... returning the unit to the Lessor by 12/31/2022 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2023

(4) Option 2 assumes No Rockport Unit 2 SCR installation by 12/31/2019... terminating the operating lease and returning the unit to the Lessor by 12/31/2019 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2020

(5) *same as 'Option 2' except assume any replacement CC capacity would be delayed until 1/1/2023 (relying on the PJM capacity & energy market in the interim)*


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1B (SCR only; No DFGD) & Option 2 (No SCR) versus Option 1A (SCR & DFGD)
'No Carbon' L/T Commodity Pricing
Option 2 (vs. Option 1A)
Option 1B (vs. Option 1A)
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
w/ End-Effects


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1A (SCR & DFGD) & Option 2 (No SCR) versus Option 1B (SCR only; No DFGD)
'No Carbon' L/T Commodity Pricing
Option 2 (vs. Option 1B)
Option 1A (vs. Option 1B)
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
(600,000)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
w/ End-Effects

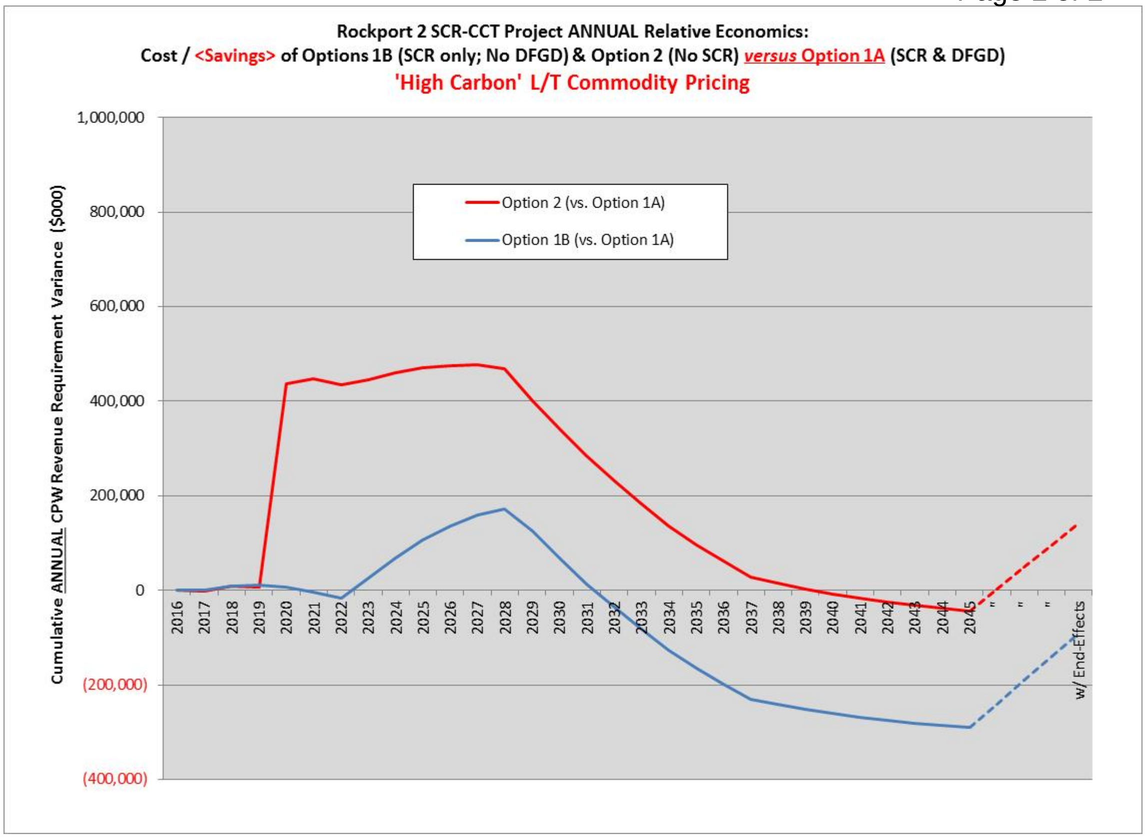
INDIANA MICHIGAN POWER COMPANY

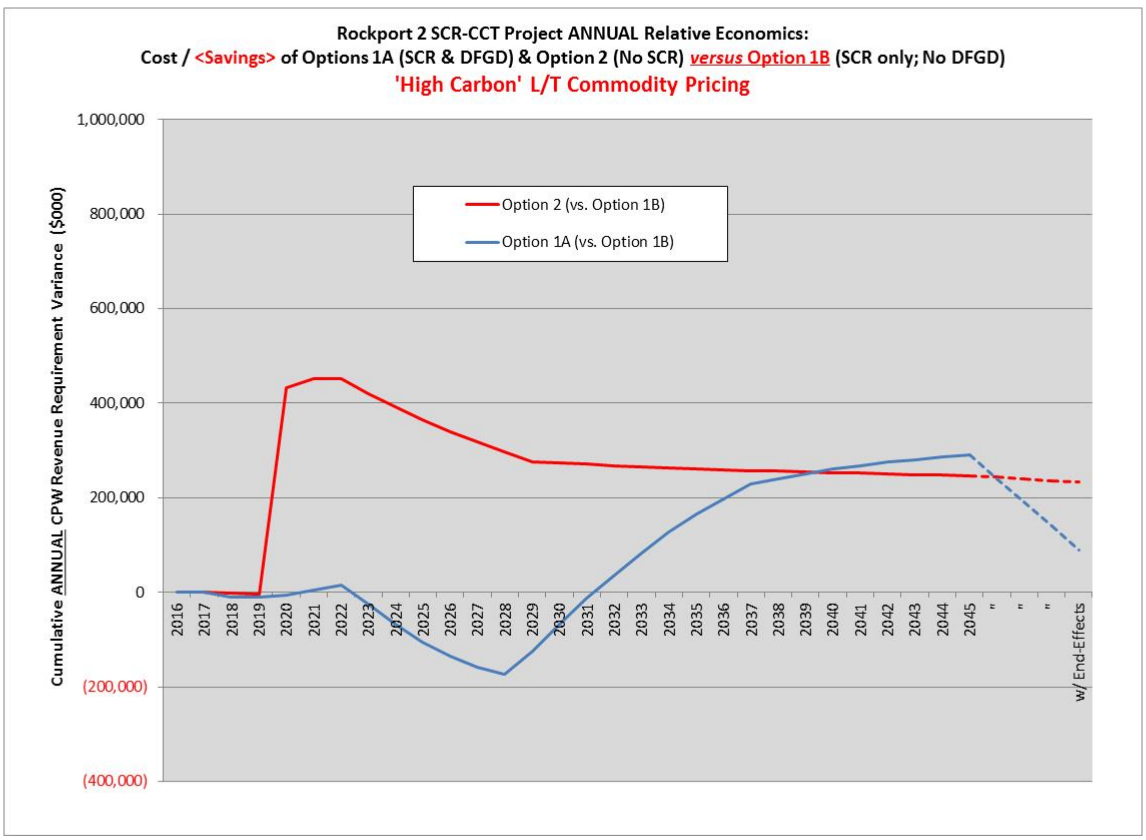
Rockport Unit 2 Disposition Analysis

"High Carbon" Long-term Commodity Pricing Forecast

	CPW ($000)			*CPW Cost/ <Savings> Over 'Option 1A'*			*CPW Cost/ <Savings> Over 'Option 1B'*		
Disposition Alternative [(1)]	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period	2016-2045 Optimization Period	Plus: End-Effects	Total Study Period
Rockport 2 SCR:									
Option 1A [(2)]	13,314,078	3,796,861	17,110,939	-	-	-	290,907	(200,633)	***90,274***
Option 1B [(3)]	13,023,172	3,997,494	17,020,665	(290,907)	200,633	***(90,274)***	-	-	-
No Rockport 2 SCR:									
Option 2 [(4)]	13,270,242	3,983,012	17,253,253	(43,837)	186,151	***142,314***	247,070	(14,482)	***232,588***
(SENSITIVITY) **Option 2A** [(5)]	13,223,077	3,999,560	17,222,638	(91,001)	202,700	***111,698***	199,906	2,067	***201,972***

Note:
(1) All cases assume Rockport Unit 1 SCR installation by 12/31/2017, and DFGD installation by 12/31/2025
(2) Option 1A assumes Rockport Unit 2 SCR installation by 12/31/2019 and DFGD installation by 12/31/2028
(3) Option 1B assumes Rockport Unit 2 SCR installation by 12/31/2019, but No DFGD installation...
returning the unit to the Lessor by 12/31/2022 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2023
(4) Option 2 assumes No Rockport Unit 2 SCR installation by 12/31/2019... terminating the operating lease and
returning the unit to the Lessor by 12/31/2019 w/ optimal replacement capacity --incl. CC-build-- by 1/1/2020
(5) *same as 'Option 2' except assume any replacement CC capacity would be delayed until 1/1/2023 (relying on the PJM capacity & energy market in the interim)*


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1B (SCR only; No DFGD) & Option 2 (No SCR) versus Option 1A (SCR & DFGD)
'High Carbon' L/T Commodity Pricing
Option 2 (vs. Option 1A)
Option 1B (vs. Option 1A)
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
w/ End-Effects


Rockport 2 SCR-CCT Project ANNUAL Relative Economics:
Cost / <Savings> of Options 1A (SCR & DFGD) & Option 2 (No SCR) versus Option 1B (SCR only; No DFGD)
'High Carbon' L/T Commodity Pricing
Option 2 (vs. Option 1B)
Option 1A (vs. Option 1B)
Cumulative ANNUAL CPW Revenue Requirement Variance ($000)
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
(400,000)
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
w/ End-Effects

Indiana Michigan Power Company
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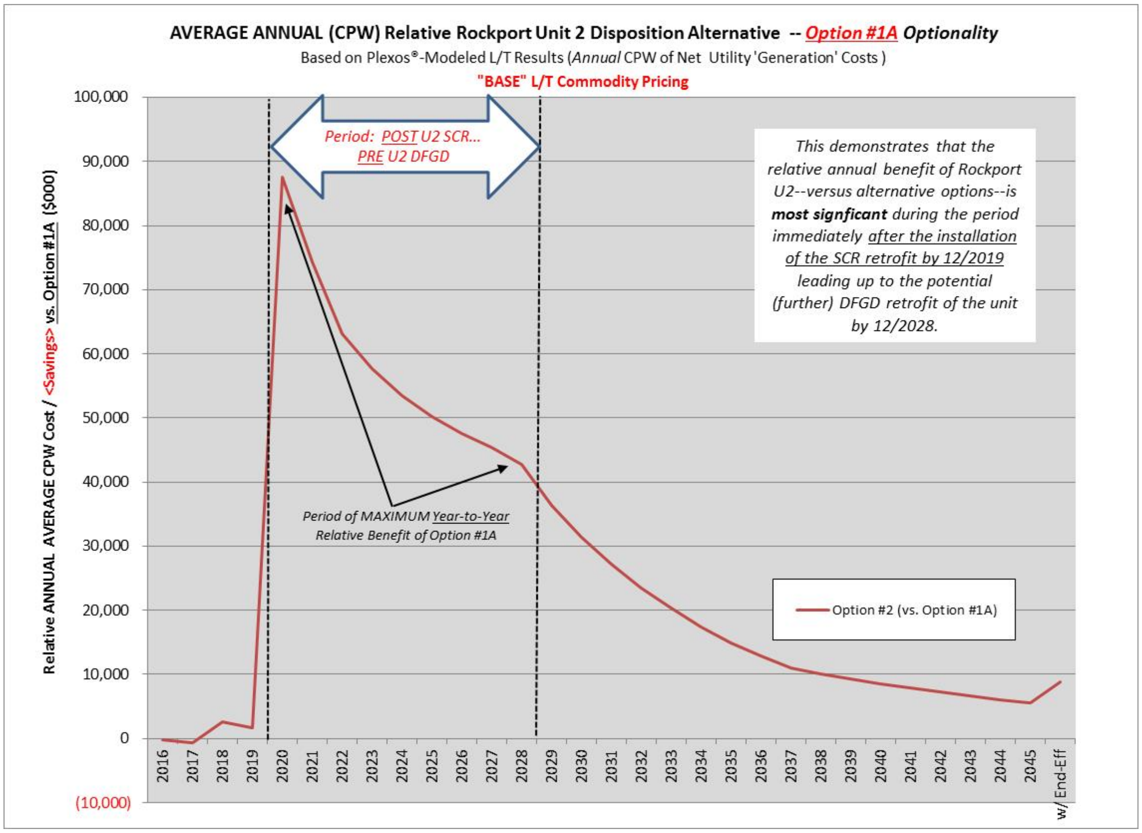
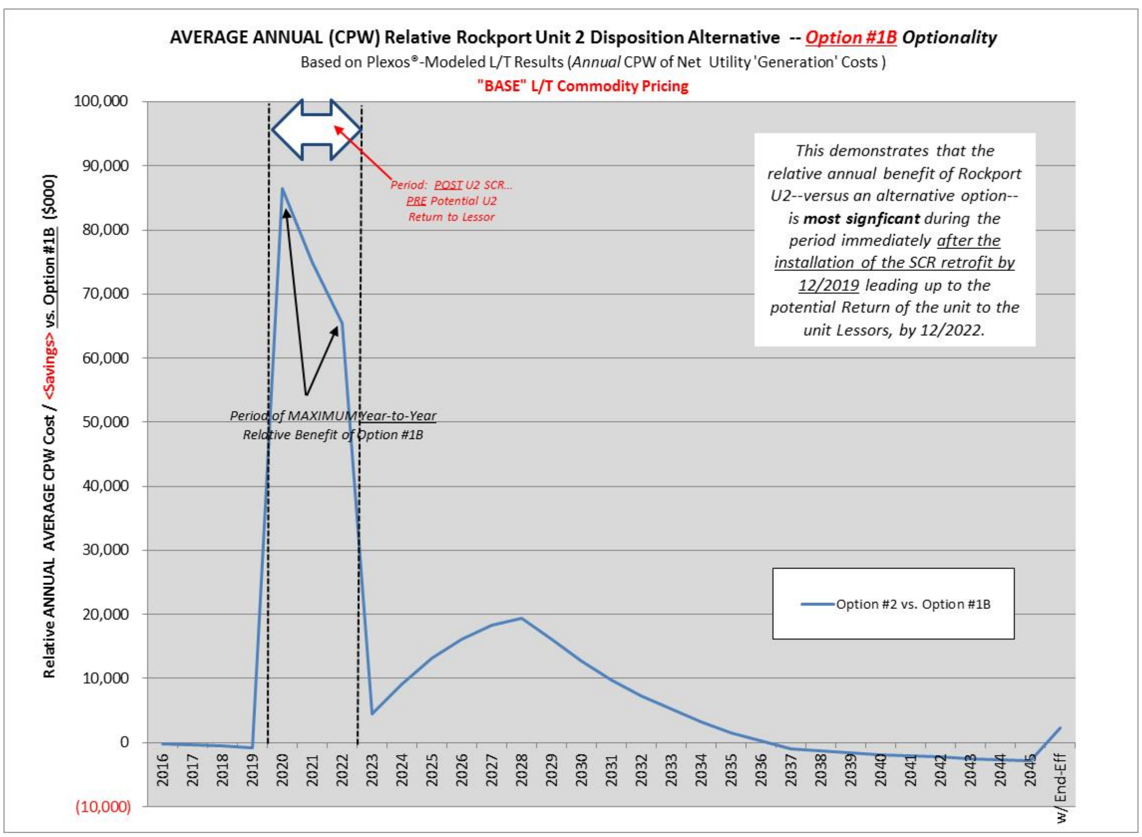
Page 1 of 2





Indiana Michigan Power Company
Attachment SCW-5
Page 2 of 2

Indiana Michigan Power Co.
Rockport Unit 2 Disposition Analysis
Under BASE L/T Commodity Pricing

Comparative SHORTER-TERM (thru 2022 & 2028) CPW of Relative I&M Net Utility "G(eneration)" Costs (1/2016 $)

Study Year #	Year		Option 1A (Retrofit RK2 with SCR (12/2019), then DFGD (12/2028)) GRAND Total Net Utility Costs (Nominal) $000	Option 1A (Cumul. PW) $000	/ Yrs	Option 1A = Total Cost, 'Per Year Avg' (PW) $000		Option 1B (Retrofit RK2 with SCR (12/2019), then Return & Replace (1/2023)) GRAND Total Net Utility Costs (Nominal) $000	Option 1B (Cumul. PW) $000	/ Yrs	Option 1B = Total Cost, 'Per Year Avg' (PW) $000		Option 2 (No SCR, Return & Replace 1/2020) GRAND Total Net Utility Costs (Nominal) $000	Option 2 (Cumul. PW) $000	/ Yrs	Option 2 = Total Cost, 'Per Year Avg' (PW) $000	Option 2 v. Option 1A Total Cost, 'Per Year Avg' (PW) $000	Option 2 v. Option 1B Total Cost, 'Per Year Avg' (PW) $000
1	2016		618,233	572,120	/1	572,120		618,233	572,120	/1	572,120		618,021	571,924	/1	571,924	(196)	(196)
2	2017		593,077	1,080,023	/2	540,012		592,271	1,079,333	/2	539,667		591,795	1,078,729	/2	539,365	(647)	(302)
3	2018		653,263	1,597,742	/3	532,581		665,960	1,607,114	/3	535,705		664,770	1,605,567	/3	535,189	2,608	(516)
4	2019		667,357	2,087,181	/4	521,795		668,223	2,097,188	/4	524,297		665,785	2,093,852	/4	523,463	1,668	(834)
5	2020	U2 SCR Installed	701,129	2,563,034	/5	512,607	U2 SCR Installed	694,348	2,568,439	/5	513,688		1,335,981	3,000,577	/5	600,115	87,509	86,428
6	2021		724,488	3,018,066	/6	503,011		709,729	3,014,201	/6	502,367	Return/ Rsrc Repl	738,121	3,464,170	/6	577,362	74,351	74,995
7	2022		855,436	3,515,268	/7	502,181		834,763	3,499,387	/7	499,912		848,054	3,957,082	/7	565,297	63,116	65,385
8	2023		809,312	3,950,575	/8	493,822	Return/ Rsrc Repl	904,622	3,985,959	/8	498,245		846,763	4,412,533	/8	551,567	57,745	4,423
9	2024		837,246	4,367,318	/9	485,258		932,678	4,450,204	/9	494,467		874,819	4,847,978	/9	538,664	53,407	9,210
10	2025		866,308	4,766,364	/10	476,636		971,905	4,897,891	/10	489,789		914,045	5,269,013	/10	526,901	50,265	13,153
11	2026		998,719	5,192,089	/11	472,008		1,105,141	5,368,980	/11	488,089		1,047,281	5,715,438	/11	519,585	47,577	16,081
12	2027		1,026,259	5,596,923	/12	466,410		1,137,164	5,817,564	/12	484,797		1,079,304	6,141,198	/12	511,766	45,356	18,387
13	2028		1,058,339	5,983,273	/13	460,252		1,144,748	6,235,457	/13	479,651		1,086,888	6,537,969	/13	502,921	42,669	19,399
14	2029	DFGD Installed	1,212,734	6,392,964	/14	456,640		1,132,735	6,618,123	/14	472,723		1,074,876	6,901,088	/14	492,935	36,295	16,083
15	2030		1,219,417	6,774,186	/15	451,612		1,106,997	6,964,199	/15	464,280		1,097,045	7,244,053	/15	482,937	31,324	12,668
16	2031		1,269,136	7,141,357	/16	446,335		1,154,607	7,298,236	/16	456,140		1,144,654	7,575,211	/16	473,451	27,116	9,805
17	2032		1,232,143	7,471,237	/17	439,485		1,111,992	7,595,949	/17	446,821		1,102,040	7,870,259	/17	462,956	23,472	7,336
18	2033		1,273,573	7,786,777	/18	432,599		1,147,592	7,880,276	/18	437,793		1,137,640	8,152,120	/18	452,896	20,297	5,194
19	2034		1,411,013	8,110,294	/19	426,858		1,267,035	8,170,781	/19	430,041		1,257,083	8,440,344	/19	444,229	17,371	3,184
20	2035		1,484,012	8,425,169	/20	421,258		1,344,199	8,455,991	/20	422,800		1,334,247	8,723,442	/20	436,172	14,914	1,541
21	2036		2,132,242	8,843,840	/21	421,135		1,999,246	8,848,547	/21	421,359		1,989,294	9,114,044	/21	434,002	12,867	224
22	2037		2,360,189	9,272,702	/22	421,486		2,216,065	9,251,221	/22	420,510		2,206,113	9,514,909	/22	432,496	11,009	(976)
23	2038		3,007,263	9,778,384	/23	425,147		2,960,441	9,749,029	/23	423,871		2,950,489	10,011,044	/23	435,263	10,116	(1,276)
24	2039		3,057,666	10,254,191	/24	427,258		3,010,710	10,217,529	/24	425,730		3,000,757	10,477,996	/24	436,583	9,325	(1,528)
25	2040		3,107,043	10,701,619	/25	428,065		3,043,137	10,655,755	/25	426,230		3,033,185	10,914,788	/25	436,592	8,527	(1,835)
26	2041		3,153,777	11,121,902	/26	427,765		3,096,380	11,068,389	/26	425,707		3,086,427	11,326,096	/26	435,619	7,854	(2,058)
27	2042		3,223,194	11,519,397	/27	426,644		3,159,894	11,458,078	/27	424,373		3,149,941	11,714,558	/27	433,873	7,228	(2,271)
28	2043		3,284,778	11,894,273	/28	424,795		3,219,131	11,825,462	/28	422,338		3,209,179	12,080,806	/28	431,457	6,662	(2,458)
29	2044		3,336,984	12,246,701	/29	422,300		3,255,197	12,169,252	/29	419,629		3,245,245	12,423,545	/29	428,398	6,098	(2,671)
30	2045		3,402,902	12,579,284	/30	419,309		3,331,461	12,494,853	/30	416,495		3,321,509	12,748,173	/30	424,939	5,630	(2,814)
36.3	w/ End-Eff			16,152,898	/36.3	444,983			16,236,528	/36.3	447,287			16,475,367	/36.3	453,867	8,883	2,304

Indiana Michigan Power Company
Attachment SCW-6

Indiana Michigan Power Co.
Rockport Unit 2 Disposition Analysis
Long-Term, Life Cycle Economics (2016-2045, with end-effects)

COMPARISON OR RELATIVE **Cumulative Present Worth (CPW) of I&M Net Utility "Generation" Costs (2016 $)**
(COST / <SAVINGS>)
Rockport Unit 2 SCR CPCN Filing
versus
I&M 2015 IRP

L/T Commodity Pricing Scenarios	RK U2 SCR CPCN OPTION #1B over OPTION #1A	2015 IRP "Fleet Modification" over "Steady State"	RK U2 SCR CPCN OPTION #2 over OPTION #1A	2015 IRP "Fleet Modification w/ NO RK U2 SCR" over "Steady State"	RK U2 SCR CPCN OPTION #2 over OPTION #1B	2015 IRP "Fleet Modification w/ NO RK U2 SCR" over "Fleet Modification"
	(A)	"As-Filed" (B)	(A)	"As-Filed" (B)	(C)	"As-Filed" (B)
"BASE" Forecast	84	174	322	~~639~~	239	~~465~~
				"As-Corrected"		"As-Corrected"
				434		260
Alternative Scenario Pricing...						
"Lower Band"	(131)	(19)	99	Analysis performed under "BASE" pricing only in 2015 IRP	230	Analysis performed under "BASE" pricing only in 2015 IRP
"Higher Band"	349	331	621		272	
"No Carbon" Price	233	333	485		252	
"High Carbon" Price	(90)	5	142		233	

[A] Attachment SCW-4-1
[B] I&M 2015 IRP; Table 22 (pg. 120)
[C] Attachment SCW-4-2

Additional Notes:
- o All scenario pricing alternatives (excluding "No CO_2") assume carbon/CO_2 pricing is effective in 2022
- o Option #1A / "Steady State" assume: RK U2 retrofitted w/ SCR (12/19) & DFGD (12/28)
- o Option #1B / "Fleet Modification" assume: RK U2 retrofit for SCR only (12/19) then unit returned to Lessor @ 12/2022 and replaced
- o Option #2 / "Fleet Modification w/ NO SCR Return assumes: No SCR and unit returned to Lessor 12/2019 and replaced
- o Each Rockport unit reflects I&M's 50% (650-MW) Ownership share; plus 70% (455-MW) Purch.Entitlement from affiliate AEP Generating Cos.' 50% ownership share

ORIGINAL

ARW

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** **APPROVED:** MAR 2 6 2018

ORDER OF THE COMMISSION

Presiding Officers:
Angela Rapp Weber, Commissioner
David E. Veleta, Senior Administrative Law Judge

On October 21, 2016, Indiana Michigan Power Company ("I&M") filed its Verified Application, along with its verified direct testimony, attachments, and supporting workpapers.

Petitions to intervene were filed on October 25, November 4, and November 15, 2016, by Citizens Action Coalition of Indiana, Inc. ("CAC"), Sierra Club, Hoosier Chapter and Valley Watch, Inc., (collectively "Joint Intervenors") and industrial customers ("I&M Industrial Group"). Each petition to intervene was granted by the Presiding Officers.

On February 3, 2017, the Indiana Office of Utility Consumer Counselor ("OUCC"), Joint Intervenors, and I&M Industrial Group filed their respective direct testimony and attachments. On February 17, 2017, I&M filed its rebuttal testimony and attachments.

Public field hearings were held on February 2, 2017, at 6:00 p.m. at South Spencer High School, 1142 N. County Rd. 275 W., Rockport, Indiana and on February 21, 2017, at Homestead High School, 4310 Homestead Rd., Fort Wayne, Indiana.

The Commission held an evidentiary hearing in this Cause on March 1 and 2, 2017, in the PNC Center, Room 222, 101 W. Washington Street, Indianapolis, Indiana, at which time the parties presented their respective evidence and offered witnesses for cross-examination. I&M, the OUCC, I&M Industrial Group, and Joint Intervenors appeared at and participated in the hearing. No members of the general public attended the hearing.

On March 17, 2017, the City of Fort Wayne, Indiana ("City") filed a Petition for Late Intervention. On March 20, 2017, the City filed the Affidavit of Douglas Fasick, Sr. Program Manager, Utilities Energy Engineering and Sustainability Services for Fort Wayne's City Utilities Division, in support of its Petition for Late Intervention. On April 3, 2017, the Presiding Officers denied the City's Petition for Late Intervention.

On April 20, and June 27, July 21, and August 10 2017, I&M filed additional information concerning the Rockport Unit 2 lease. On September 8, 2017, I&M Industrial Group and the OUCC filed their response to I&M's submission of additional information concerning the Rockport Unit 2 lease. On September 21, 2017, I&M submitted its reply. On November 21, 2017 and January 9, 2018, I&M filed additional information concerning the Rockport Unit 2 lease. On February 23, 2018, I&M filed *Indiana Michigan Power Company's Verified Motion for Decision* ("Motion"). No party to the proceeding filed a response to the Motion.

Based upon the applicable law and evidence presented, the Commission now finds as follows:

1. Notice and Jurisdiction. Notice of the hearing in this Cause was given and published as required by law. I&M is a "public utility" as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.7-2, and an "eligible business" as defined in Ind. Code § 8-1-8.8-6. Ind. Code chs. 8-1-8.7, 8.8, and Ind. Code §§ 8-1-2-6.1, 8-1-2-6.7, and 8-1-2-6.8 give the Commission authority to issue a certificate of public convenience and necessity ("CPCN") and to authorize certain accounting methods, financial incentives, and timely cost recovery related to the installation and use of clean energy projects, clean coal technology ("CCT"), and qualified pollution control property ("QPCP"). Therefore, the Commission has jurisdiction over I&M and the subject matter of this proceeding in the manner and to the extent provided by Indiana law.

2. I&M's Characteristics. I&M, a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"), is a corporation organized under the laws of the State of Indiana, with its principal offices at Indiana Michigan Power Center, Fort Wayne, Indiana. I&M is engaged in rendering electric service in the State of Indiana, and owns and operates plant and equipment within the State of Indiana that are in service and used and useful in the generation, transmission, distribution, and furnishing of such service to the public.

3. Background. I&M's operations are subject to federal environmental laws and rules promulgated by the United States Environmental Protection Agency ("US EPA"). These environmental laws and rules include requirements to directly or indirectly reduce or avoid emissions of nitrogen oxides ("NO_x") from coal-fired generating units and the Prevention of Significant Deterioration and Nonattainment New Source Review ("NSR") provisions, which are part of the Federal Clean Air Act. As part of the Federal Clean Air Act and related consent decree executed with the Department of Justice ("DOJ"), the US EPA and other parties, I&M must retrofit Rockport Unit 2 with selective catalytic reduction ("SCR") technology by December 31, 2019.[1] There are also several US EPA regulatory initiatives in various stages of development that may also necessitate installation of SCR at the Rockport Unit 2.

4. **Rockport Unit 2.** The Rockport plant is located in Spencer County, Indiana and consists of Rockport Unit 1 and Unit 2 that have net capacity of 2600 MW. Rockport Unit 2 was placed in service in 1989. For 2016, the nominal 2,227 MWs of Rockport, which I&M owns or purchases, represent approximately 49% of I&M's total generating capacity.

5. **Rockport Unit 2 Lease.** I&M and AEP Generating Company ("AEG") received approval on March 30, 1989, in consolidated Cause Nos. 38690 and 38691, to enter into a sale and leaseback transaction for Rockport Unit 2. As a result, I&M jointly leases Rockport Unit 2 with AEG, with I&M's leased share being 50% of the unit. As the part owner and purchaser, I&M is responsible for 85% of the Rockport Unit 2 costs. Fifty percent of this total is associated with I&M's ownership share. The remaining 35% is incurred by I&M pursuant to a unit power agreement with AEG approved by the Federal Energy Regulatory Commission ("FERC").

The Rockport Unit 2 lease terminates on December 7, 2022, unless it is extended under the terms of the lease or through the mutual agreement of the parties to the lease. The lease also provides for an early termination of the lease in the event that Rockport Unit 2 is "economically obsolete." If the lease is terminated early due to obsolescence, I&M is required by the terms of the lease to pay the lessors an amount referred to in the lease as termination value, which is a calculable amount intended to essentially make the lessors whole for the loss of the lease payments.

6. **Relief Sought.** I&M requests a CPCN under Ind. Code ch. 8-1-8.7 to install SCR technology to allow I&M to reduce NO_x emissions from Rockport Unit 2 (the "Rockport SCR Project") to comply with the consent decree as well as future environmental regulations that could further necessitate the need for SCR technology on Unit 2.

To support this requested relief, I&M presented economic analysis evaluating two disposition alternatives associated with the Rockport plant: (1) retrofit Unit 2 with SCR technology; or (2) forego installation of the SCR technology and return Unit 2 to the lessor early. Mr. Weaver analyzed each alternative under two different sub-options:

- **"Option 1A"** – This option reflects installation of SCR technology on Unit 2 and the unit's continued operation through retirement at the end of the unit's useful life.
- **"Option 1B"** – This option reflects installation of SCR technology on Unit 2, but also assumes the return of the unit to the lessor by the December 2022 lease termination date.

[1] On November 16, 2017, the United States District Court for the Southern District of Ohio issued an order tolling the deadline to install a SCR system at Rockport Unit 2 until June 1, 2020.

- **"Option 2"** – This option represents not installing the Rockport SCR Project and returning Unit 2 to the lessors by December 31, 2019, which would require payment of the lease termination value effective as of that date (approximately $716 million) and the replacement of Unit 2's capacity and energy with some combination of resources by January 1, 2020.
- **"Option 2A"** – This sensitivity analysis follows Option 2, but assumes any replacement combined cycle capacity would be delayed until January 1, 2023, with I&M relying on the PJM capacity and energy market in the interim.

I&M also seeks cost recovery for the Indiana jurisdictional portion of I&M's ownership share of the Rockport SCR Project in accordance with the Commission's authority under Ind. Code § 8-1-8.8-11 and related statutes and regulations. I&M requests the Commission authorize the depreciation of I&M's ownership share of the Rockport SCR Project over a period of ten years. Finally, I&M requests ongoing review of the Rockport SCR Project in accordance with Ind. Code § 8-1-8.7-7.

7. <u>I&M's Direct Evidence</u>. Paul Chodak III, Executive Vice President – Utilities for AEP discussed I&M's generation resource portfolio and testified that for over 30 years, Rockport has been a cornerstone of I&M's generation fleet and has achieved low emission rates of NO_x and sulfur dioxide by consuming predominantly low-sulfur Power River Basin ("PRB") coal. He recognized that the outlook for coal generation is changing. He added that the continued safe, reliable, and efficient operation of the Rockport is vital to meeting the needs of I&M's customers for dependable and affordable electric service. Mr. Chodak concluded that the Rockport SCR Project is a cost-effective means of maintaining the availability of low cost, coal-fired generation that complies with environmental regulations. He stated that approval of the Rockport SCR Project will allow the plant to continue to serve I&M's customers' needs, provide jobs and taxes to the community, and mitigate the rate impact on customers. He said the Rockport SCR Project is the most reasonable option to permit Rockport to continue to provide generation needed to serve I&M's customers' needs while maintaining reasonable rates.

Mr. Chodak discussed the ownership of Rockport and described I&M's long-term lease of Rockport Unit 2 approved by the Commission in 1989. Among other things, Mr. Chodak stated that during the term of the lease, I&M and AEG are responsible for installing, owning, and operating major environmental controls, such as the SCR, to assure that the plant complies with all regulations. Mr. Chodak testified that the lease also provides for early termination in the event that Rockport Unit 2 is "economically obsolete." He added that if the lease is terminated early due to obsolescence, I&M is required by the terms of the lease to pay the lessors an amount referred to in the lease as termination value, which is a calculable amount intended to essentially make the lessors whole for the loss of the lease payments. For example, Mr. Chodak explained that if the lease was terminated as of January 1, 2020, due to becoming economically obsolete as a result of not installing and operating the requisite SCR system, the termination value owed by I&M and AEG to the lessors would be approximately $716 million.

Mr. Chodak explained that the Rockport Unit 2 lease terminates on December 7, 2022, unless it is extended under the terms of the lease or through the mutual agreement of the parties to the lease. He stated that under the terms of the lease, I&M has options to extend the lease at the current fixed lease payment or for a lease payment agreed upon in accordance with the fair market value. He testified that I&M engaged in confidential discussions with the lessors regarding what might occur at the end of the lease and added that at this time, I&M has not exercised its option to renew the lease under the current fixed rate payment or negotiated a payment based on fair market value, and it is not known whether it will do so. Mr. Chodak stated that for purposes of evaluating whether to install the SCR on Rockport Unit 2 to comply with federal environmental mandates, I&M evaluated the possibility that it will not have access to the output of Rockport Unit 2 beyond 2022.

Mr. Chodak explained the significant uncertainty surrounding the future of Rockport Unit 2 as a resource to meet the needs of I&M's customers makes long-term decisions about I&M's generation portfolio more complex. He identified pending litigation between I&M and the lessors and said I&M continues to explore all options as it determines the best way to serve customers. Mr. Chodak explained that as shown in I&M's Integrated Resource Plan ("IRP"), there are several different paths available and the costs of several of the options are relatively comparable. He added that I&M uses its IRP as a tool for determining how to manage its business in the interest of customers. Mr. Chodak testified that while clarity on the future of Rockport Unit 2 would be valuable, I&M does not have the luxury of time to wait for matters to become clearer.

Mr. Chodak testified that what is clear at this point is that under the current circumstances, installing and operating SCR technology on Rockport Unit 2 in compliance with federal environmental requirements is the correct decision for I&M and its customers. He stated that even if the lease terminates at the end of its initial term in 2022, it makes economic sense for I&M and its customers to install and operate SCR technology for the remaining time that I&M and its customers would benefit from the output of the unit. Mr. Chodak added that if future developments alter that judgment, I&M is committed to timely advising the Commission and stakeholders about those developments and the impact they have on Rockport Unit 2. He added, at this point, work on the Rockport SCR Project must begin if the Rockport SCR Project is to be successfully completed and thus I&M needs to move forward with its filing in this Cause.

Mr. Chodak and I&M Witness Frank R. Pifer, Vice President – Project Controls and Construction for the American Electric Power Service Corporation ("AEPSC"),[2] testified that the Rockport SCR Project will install an SCR system that is advanced clean coal technology designed to reduce NO_x emissions associated with the combustion of coal. Mr. Pifer has managerial responsibility for the Rockport SCR Project.

Mr. Pifer described the processes that are being utilized to retrofit Rockport Unit 2 with SCR technology to reduce the plant's emissions of NO_x. He described the expected performance of the technology and he discussed the current cost estimate for the proposed Rockport SCR Project.

Mr. Pifer testified that Rockport Unit 2 is already equipped with conventional combustion controls to reduce the formation of NO_x, including low NO_x burners and overfire air. He stated that the addition of SCR technology is required to satisfy the requirements of the consent decree and explained that SCR is a proven, reliable technology used throughout the electric utility industry

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[2]At the time I&M filed its case-in-chief, Mr. Pifer was Managing Director of Projects with AEPSC.

to reduce NO_x emissions. Mr. Pifer described the SCR technology and discussed the anticipated NO_x emission rate associated with the installation of the SCR on Rockport Unit 2. He testified that the SCR is designed to accommodate four catalyst layers, but will operate with only two layers initially due to the fan capacity of the unit. He explained that there is a significant pressure drop that occurs when operating the SCR with three or four layers of catalyst and stated that installing fans as part of the Rockport SCR Project would increase the cost of it, and those fans would be rendered obsolete in any future flue gas desulfurization ("FGD") installation. He explained that operation of an FGD will require much more powerful fans, and separate structural boiler stiffening to provide sufficient air flow through the SCR and the FGD. He testified that it is in the best interest of I&M's customers to optimize the SCR design with the existing fan capacity and to defer any investment in additional fan capacity at this time. Mr. Pifer noted that this same design approach was used for the Rockport Unit 1 SCR installation.

Mr. Pifer provided an overview of the current plan for the Rockport SCR Project and discussed the major benefits derived from AEP's phased approach to construction projects. Mr. Pifer described the AEP process for selecting technology, the original equipment manufacturer ("OEM") vendor and the construction contractor. He also discussed the steps AEP takes to ensure that project costs are reasonable and necessary. Mr. Pifer described AEP's processes to manage project cost, schedule, procurement/contract, risk, safety, and quality.

Mr. Chodak and Mr. Pifer explained that the cost of the Rockport SCR Project in total is estimated to be approximately $274.2 million (excluding allowance for funds used during construction ("AFUDC")). Mr. Pifer explained that this cost estimate includes the installation of the SCR and other associated upgrades to plant equipment as well as the AEP allocated cost for support of the Rockport SCR Project. He discussed how the cost estimate was developed, compared it to the cost estimate for the Rockport Unit 1 SCR project, discussed the cost estimate accuracy, and explained how the cost estimate will be further refined as the phased development process proceeds. Mr. Pifer also discussed the methods I&M employs to mitigate the risk of cost escalation. He concluded that the cost estimate for the Rockport SCR Project is reasonable considering the development basis and site-specific engineering and design work to date. Mr. Pifer also explained that aside from the capital cost of the Rockport SCR Project, there will be fixed and variable operation and maintenance ("O&M") costs associated with the operation of the Rockport Unit 2 SCR.

Mr. Pifer testified that SCR equipment is identified by name as part of the definition of clean energy projects in Ind. Code § 8-1-8.8-2(1)(B). He testified that this technology was not in commercial use at the same or greater scale in the United States as of January 1, 1989. He also noted that the Commission's Order in *Petition of Southern Indiana Gas and Electric*, Cause No. 41864 (IURC 8/29/2001) (at 4-5) states that SCR technology was selected by the Department of Energy for funding under its Innovative Clean Coal Technology Program and was finally approved for such funding on or after January 1, 1989. He added that SCR systems are used to reduce emissions of NO_x, but do not affect the plant's ability to consume higher sulfur fuels, with higher sulfur being a general characteristic of Indiana coal. Mr. Pifer also testified that the existing activated carbon injection ("ACI") system and the Dry Sorbent Injection ("DSI") systems being utilized at the plant will be used with the SCR. He added that the installation of the SCR control technology will allow Rockport Unit 2 to continue operations beyond December 31, 2019, and added that as a result, Rockport will continue to provide value to I&M's customers and formal assessment of Rockport disposition options beyond this point can be performed in the future.

John C. Hendricks, Director Air Quality Services within the Environmental Services Division of the AEPSC, discussed the regulation of NO_x emissions, the consent decree, future environmental regulations, including those that could further necessitate the need for SCR technology on Rockport Unit 2, and associated permitting necessary to support the proposed retrofit. Mr. Hendricks and Mr. Pifer explained that the SCR retrofit will directly reduce emissions of NO_x by reacting NO_x with ammonia on the surface of a catalyst. Mr. Hendricks addressed the impacts of NO_x emission to the atmosphere and discussed the regulation of NO_x emissions under the Federal Clean Air Act. Mr. Hendricks explained that as part of the Federal Clean Air Act and AEP's related consent decree, I&M must retrofit Unit 2 of the plant with SCR technology by December 31, 2019. Mr. Hendricks explained how the consent decree is related to the Federal Clean Air Act and briefly discussed other consent decrees related to the Federal Clean Air Act and the history of the consent decree applicable to I&M. He also identified several US EPA regulatory initiatives in various stages of development that may necessitate the installation of SCR technology at Rockport Unit 2 and discussed the federal environmental mandate that currently requires the SCR retrofit at Rockport Unit 2. Finally, Mr. Hendricks described the other environmental regulations that were considered in I&M's economic modeling effort. Mr. Hendricks added that the proxy for carbon regulation used by Mr. Weaver in this analysis reasonably accounts for potential greenhouse gas regulation.

Scott C. Weaver, AEPSC Managing Director-Resource Planning and Operational Analysis, evaluated the cost and feasibility of an option to retire and replace Rockport Unit 2. Mr. Weaver also described the modeling process undertaken to evaluate the relative economics of the alternative Rockport Unit 2 disposition options, including a discussion around the major input parameters and key drivers, chief among them the anticipated long-term prices of natural gas and energy as well as carbon dioxide ("CO_2") that could impact the Rockport Unit 2 dispatch priority. In addition, Mr. Weaver affirmed that the analysis is consistent with I&M's 2015 IRP, and discussed the results of these economic modeling analysis.

Mr. Weaver presented the resource planning-related criteria that are introduced and considered as part of this evaluation of alternative options surrounding Rockport Unit 2 and focused specifically on the discrete economic evaluations performed that led to I&M's conclusions and recommendations in this Cause. Mr. Weaver's testimony addressed: the Rockport Unit 2 disposition options; the December 31, 2019 disposition date; the lease agreement and related terms, including the lease termination value as of that date estimated at $715.7 million; the evaluation process undertaken to assess potential costs of retrofit requirements; the terms of the consent decree; and additional US EPA requirements.

Mr. Weaver discussed the capacity need that would be influenced by this Rockport Unit 2 disposition decision and explained how the disposition alternatives were analyzed. Mr. Weaver presented his analysis with and without "end-effects." Mr. Weaver discussed I&M's evaluation of demand-side/energy efficiency, demand response, and renewable resources in determining the least-cost alternative to meet its long-term obligations. Mr. Weaver also explained that natural gas pricing is one of the key drivers in this analytical process and provided an overview of the forecasted fundamental commodity pricing in the Rockport Unit 2 disposition analysis. He testified that an array of five unique long-term commodity pricing scenarios were utilized in the analysis, consisting of a base view; two price banding sensitivity views; and two CO_2/carbon views. Mr. Weaver presented the modeling results and explained that the analysis indicate that a nearer-term solution that would call for the retrofitting of Rockport Unit 2 with SCR technology by December 31, 2019, would be the most economical option for I&M and its customers. Mr. Weaver explained that over the relative shorter term, the results suggest that CO_2 would likely not be a significant issue. He said that recognizing that Option 1B and Option 2 are largely focused on the relative economics of those alternatives for the years 2020 through 2022 only, one would anticipate that by virtue of a 2022 start-date for the Clean Power Plan ("CPP") (represented by a 2022 carbon tax proxy start-date in the modeling), it would have minimal impact on the relative economic results. He said this fact is borne out when comparing the relative results found on Attachment SCW-4-2. He discussed the optionality offered by the Rockport SCR Project and explained that the Rockport SCR Project could potentially serve to "bridge" the unit for a period of nine years beginning with the required December 2019 SCR in-service date up to the timeframe in which a more capital-intensive dry FGD retrofit which, for purpose of the analysis, would be required to be installed by December 31, 2028. Mr. Weaver discussed the relative near-term economic advantage of the Rockport SCR Project and stated that the analysis suggests that the Rockport SCR Project would afford the ability to capitalize on the significant relative value it would offer I&M and its customers, even for a brief, three-year period that would result in a potential return to lessor.

Mr. Weaver concluded that the robust unit disposition economic analysis I&M performed would point to the nearer-term retrofitting of Rockport Unit 2 with SCR technology by December 31, 2019, (via either Option 1A or Option 1B) as being a reasonable and least-cost solution over the long-term economic study period evaluated when compared to a view that would not install an SCR but rather terminate the Rockport lease as of that same date and pay the lessors a stipulated lease termination value (Option 2).

Mr. Weaver added that the Rockport SCR Project would serve to economically preserve a future option to potentially install dry FGD environmental controls on Unit 2 by the end of 2028, as required under the consent decree. He stated that even under the assumption I&M would ultimately choose not to proceed with a Unit 2 dry FGD retrofit, the economic analysis supports implementation of the Rockport SCR Project. He stated it is in the best interest of its customers to leverage the current investment of a thermally efficient Rockport Unit 2 by recommending it be retrofitted with SCR technology by December 31, 2019, so as to be in compliance with the consent decree as well as other potential US EPA rulemaking that would require the reduction of NO_x emissions. As summarized by Mr. Chodak, the Rockport SCR Project is a reasonable business decision regardless of whether the unit is a resource available to I&M after 2022 because declaring the unit to be economically obsolete now would be a more costly alternative for I&M's customers.

Andrew J. Williamson, I&M Director of Regulatory Services, explained I&M's requested accounting and ratemaking treatment related to the costs associated with I&M's ownership share of the Rockport SCR Project.

Mr. Williamson explained that I&M seeks timely cost recovery via I&M's clean coal technology rider ("CCTR") of the following costs associated with I&M's ownership share:

carrying costs including all applicable federal and state income taxes, depreciation, associated O&M expense, and associated consumable and property tax expenses.

He stated that consistent with I&M's previous CCTR filings within Cause No. 44523 ECR-X, I&M requests approval to establish rates using the forecasted costs associated with the period in which future requested rates are expected to be in effect. He added that I&M also requests to recover gross revenue conversion factor ("GRCF") costs in the calculation of the CCTR revenue requirement associated with the Rockport SCR Project, and said the calculation and application of the GRCF is consistent with the GRCF approved by the Commission in other I&M riders. He stated that I&M requests to implement construction work in progress ("CWIP") ratemaking treatment for I&M's ownership share of the Rockport SCR Project costs.

With regard to the proposed accounting treatment for I&M's ownership share, Mr. Williamson explained that I&M seeks authority to: depreciate I&M's ownership share once the assets are in-service, over a ten-year period; defer and record as a regulatory asset the associated depreciation, carrying costs, O&M, consumable and property tax expenses until such time as these costs receive ratemaking treatment through the CCTR or are otherwise reflected in basic rates; and utilize, via the CCTR, traditional over- or under-recovery accounting for the annual true-up of rider revenues to actual costs consistent with I&M's past CCTR tracker reconciliations.

Mr. Williamson explained how the Rockport SCR Project costs are segregated and recorded and how I&M will account for its ownership share of the Rockport SCR Project. He stated that I&M proposes to begin CWIP recovery for I&M's ownership share of the Rockport SCR Project's capital costs once it has been under construction for at least six months and the associated costs are included in CCTR rates. He said I&M will record AFUDC on CWIP balances in accordance with 170 IAC 4-6-13 as defined and prescribed in the FERC Uniform System of Accounts ("FERC USoA") until CWIP ratemaking treatment begins or the associated assets are placed in-service. Mr. Williamson testified that I&M proposes to include its ownership share of the Rockport SCR Project's associated O&M expense, including consumable expenses, in its CCTR and requests the Commission authorize I&M to defer O&M and consumable expenses incurred during the operation of the Rockport SCR Project until such time as these costs are reflected in the CCTR.

Mr. Williamson explained how I&M will account for and determine incremental O&M expenses related to the Rockport SCR Project, discussed how I&M is proposing to depreciate the capital investment and explained I&M's proposal regarding property tax expenses related to I&M's ownership share of the Rockport SCR Project. Mr. Williamson also explained what return on equity I&M proposes to use to compute the revenue requirement for its ownership share.

Mr. Williamson concluded that the request for authority to defer the associated carrying costs, depreciation, O&M, consumable and property tax expenses until such costs are reflected in the CCTR is reasonable and necessary to ensure timely recovery of the Rockport SCR Project. Moreover, he said it would be difficult and inefficient for I&M to perfectly time a base rate case, or base rate cases, with the in-service date of the Rockport SCR Project. He testified that the statutory and regulatory framework applicable to this proceeding recognizes this and was established to avoid the adverse financial impact that could otherwise occur during the interim period between the Rockport SCR Project in-service date and the inclusion of I&M's ownership share of the costs in I&M's basic rates. He stated that allowing I&M to recover these costs through the CCTR also avoids the unnecessary cost and time commitment associated with filing a base rate case.

Mr. Williamson described how the ratemaking treatment related to I&M's ownership share of the Rockport SCR Project will be effectuated and explained how I&M will treat the return associated with the requested ratemaking treatment for its ownership share in its fuel cost adjustment filings. He stated the requested ratemaking treatment will continue until I&M's ownership share of the Rockport SCR Project is included in basic rates, including the associated return and all aforementioned operating costs.

Mr. Williamson also discussed the accounting that will occur if the Rockport SCR Project is retired prior to being fully depreciated. He testified that at the end of the lease, the Rockport SCR Project will be retired for accounting purposes. He said I&M will follow the accounting for retirements according to the FERC USoA, the same accounting used for any other retired capital asset. He described how any under-depreciated book value would be treated upon retirement and explained that any remaining balance will be included in future I&M filings until it has been fully recovered through the ratemaking process.

Mr. Williamson also explained I&M's request for ongoing review of the construction of the Rockport SCR Project to be conducted annually as part of I&M's proposed annual CCTR proceedings and discussed how the ratemaking treatment will be effectuated. He stated that I&M will include progress reports of construction, updated cost estimates, and any revisions to cost estimates for the Rockport SCR Project in the annual CCTR filing.

Mr. Williamson explained that I&M estimates the annual rate impact of the ownership share for the Indiana retail jurisdiction for all rate classes to be 1.6% increase upon completion of the Rockport SCR Project.

8. OUCC's Evidence. Edward Rutter, Chief Technical Advisor in the OUCC Resource Planning and Communications Division, discussed the Rockport SCR Project and the OUCC's review of I&M's modeling results.

Mr. Rutter testified that a simple analysis of I&M's proposal looks at the immediate and total ratepayer cost. He said under I&M's proposal, the cost to retrofit Rockport Unit 2 with SCR technology is approximately $274.2 million. He said the cost to terminate the lease at December 31, 2019, is $716 million. He said Indiana ratepayers would be responsible for paying their allocated portion of I&M's costs, whether for installation or termination. He stated that the I&M share of the Rockport SCR Project cost is $137.1 million, which would result in a rate increase for Indiana ratepayers of 1.6% collected through the CCTR. He said assuming the lease would terminate January 1, 2020, the SCR retrofit technology was not implemented, and only the lease termination costs were allowed to be recovered, the Indiana rate impact is an increase of 3.45% collected through the existing CCTR. He added that if I&M were allowed to not only recover the lease termination costs in the form of annual depreciation or amortization, but also a return on the net unrecovered lease termination cost, less accumulated depreciation or amortization, the rate impact is an increase in rates of 6.44% collected through the CCTR.

Mr. Rutter stated that the OUCC recommends the Commission allow I&M to install SCR technology on Rockport Unit 2, and require I&M to robustly model alternatives to the generation provided under the lease agreement for Rockport Unit 2 in its next IRP.

Cynthia Armstrong, Senior Utility Analyst in the OUCC Electric Division, discussed the environmental regulations and requirements concerning the Rockport SCR Project as well as future environmental regulations and how the costs for these regulations were considered in I&M's economic analysis supporting the Rockport SCR Project.

Ms. Armstrong testified that while there are many requirements that could obligate I&M to install an SCR on Rockport Unit 2, the three main requirements influencing the proposal are the recent revision to the primary eight-hour ozone national ambient air quality standards ("NAAQS"), the update to the cross state air pollution rule ("CSAPR"), and the consent decree. She described each of these requirements and how they may impact the decision to retrofit Rockport Unit 2 with an SCR.

With respect to future environmental regulations, Ms. Armstrong testified that the main environmental regulations that could impact Rockport's operations over the next decade are the coal combustion residuals ("CCR") rule, the updated steam electric utility effluent limitation guidelines ("ELGs"), the cooling water intake structure rule, carbon regulations and the consent decree. She testified that I&M has made assumptions for the cost of these regulations in its economic analysis, and they appear to be within the reasonable range for the expected retrofits these regulations would require. She noted, however, that the costs assumed for these regulations are estimates based on preliminary studies, and the costs of compliance may be more once in-depth, site-specific engineering studies are completed.

Ms. Armstrong concluded that the SCR is required for Rockport Unit 2 to operate beyond 2019, and the consent decree is driving this requirement. She said installing the Unit 2 SCR may help to improve the operational flexibility of the unit with regards to compliance with the CSAPR, but Rockport can comply with the CSAPR without the Unit 2 SCR. She added that I&M has assumed reasonable costs for future environmental compliance, specifically for the CCR Rule, the updated ELGs, and the consent decree. She said while the costs could be greater, I&M has made a reasonable effort to estimate costs on the technology expected to comply with these requirements.

Wes R. Blakley, Senior Utility Analyst for the OUCC reviewed I&M's proposed accounting and ratemaking for the Rockport SCR Project and discussed the proposed tracking of I&M's ownership share. He said that I&M's requested cost recovery is the same treatment that was approved for its 50% ownership share of the Rockport Unit 1 SCR in Cause No. 44523. He said the OUCC does not agree with I&M's proposed ratemaking treatment for any under-depreciated asset that may happen as a result of early lease termination. He said any decision regarding recovery of the value of under-depreciated plant should be fully investigated in a base rate case, not in a tracker or other abbreviated proceeding. Mr. Blakley concluded that I&M's accounting and ratemaking treatment request for its Rockport Unit 2 SCR is consistent with the

Commission's rules and Indiana statutes. He said these are the same statutes and rules I&M applies to its current ECR tracker for its Rockport Unit 1 SCR.

9. **Industrial Group's Evidence.** Nicholas Phillips, Jr., a Managing Principal of Brubaker and Associates, Inc., reviewed the Rockport SCR Project and requested ratemaking treatment. Mr. Phillips discussed significant elements of I&M's requested ratemaking treatment and raised concerns about the proposal.

Mr. Phillips contended that I&M's request to depreciate the Rockport SCR Project over ten years is at odds with the 28-year life used by the AEG leased portion of the same SCR. He said I&M should not be permitted to use a depreciation period for the I&M-owned portion of the lease that is nearly three times faster than the depreciation period of the AEG portion. He said this is especially true given the possibility that I&M ratepayers may only benefit from the SCR for three years before termination of the lease. He added that if a 28-year period is appropriate for AEG, it is appropriate for the half of the plant leased by I&M. He stated, however, that if the applicable law restricts the maximum period to 20 years, the 20 year maximum should be used. Mr. Phillips also discussed prior testimony from Mr. Chodak in Cause No. 44033 and stated that a decision whether to renew, terminate, or buy out the Rockport Unit 2 lease is more than five years overdue.

Mr. Phillips stated that based on the SCR construction schedule and the current lease expiration date, the SCR would be used and useful in the provision of electric service to Indiana ratepayers for about 35 months or slightly less than three years. He disagreed that I&M should be allowed to recover the undepreciated balance from Indiana ratepayers in that circumstance. He said the Commission should either specifically find that I&M may not recover any undepreciated balance for the SCR from ratepayers or any CPCN granted to I&M should be conditioned on the SCR remaining used and useful to I&M ratepayers. He explained Indiana's CPCN law confers benefits on utilities' ability to recover their costs once a certificate is granted. However, he said the certificate is only in the public interest after December 7, 2022, if the SCR property remains used and useful to I&M ratepayers. He explained why he believed his recommendation was consistent with Ind. Code ch. 8-1-8.7.

Mr. Phillips testified that the appropriate method to allocate costs for the ownership share and allocated share is the allocation method used to allocate fixed production costs to classes as approved by the Commission in I&M's most recent base rate case. He said the method approved by the Commission in Cause No. 44075 to allocate fixed production cost to classes is the six coincident peak ("6 CP") method and explained why this method is appropriate for allocation of fixed production investment in the CCTR. He stated it was consistent with the Commission's rules, and the Commission's prior approval of the 6 CP method. He testified that if the Commission allows I&M to include AEG cost increases in the CCTR, those costs should be allocated to customer classes in the same manner as the Indiana jurisdictional SCR costs. He said he believed his proposal was consistent with I&M's proposal to allocate these costs.

Mr. Phillips stated there is a risk that a significant portion of the Unit 2 SCR costs will be stranded in the event that the lease is not renewed. He said under these circumstances, the Commission should cap the costs recoverable in the rider for the Unit 2 SCR at I&M's current estimate. He stated any potential cost overruns can be addressed in a future rate case.

Mr. Phillips also testified that without the 1,105 megawatt output of Rockport Unit 2 after December 7, 2022, I&M would be capacity deficient. He said I&M depends on four large generating units to provide adequate capacity to serve its customers, and that Rockport Unit 2 is the newest of the four units. He stated that since a rule of thumb is to bring a combined cycle unit online is approximately five years, it is in Indiana ratepayers' interest that I&M set forth a contingency plan in the near future and I&M should be required to do so by the Commission.

10. **Joint Intervenors' Evidence.** Jeremy I. Fisher, a Principal Associate with Synapse Energy Economics, Inc., assessed I&M's analysis, examined if the installation of controls at this time is in the interest of I&M's ratepayers, discussed the basic specifications for the SCR in light of I&M's regulatory requirement, and assessed if I&M's proposal is consistent with its requirements. Mr. Fisher did not substantially disagree with the structure of I&M's decision framework, which seeks to understand the balance between short-term optionality and long-term risk, but added that such a decision ought to rely on a robust analysis, reasonable inputs, and a reasonable interpretation of the analysis results.

Mr. Fisher claimed I&M has been disingenuous about its interpretation of the analysis results by inappropriately relying on flawed results that emphasize outcomes which might occur more than 30 years in the future (the "end-effects period"). He further claimed that the results from the core analysis period run counter to I&M's findings. He said, the end-effects error imposed by I&M (i.e., assuming no additional capital costs at Rockport after 2045) is highly biased for Option 1A. He stated therefore, removing end-effects decreases the cumulative present worth ("CPW") of the scenarios, but increases the cost of Option 1A by about $150-$170 million relative to the other options examined by I&M. He stated that this correction inverts the position of Options 1A and 1B, with Option 1B slightly more cost effective than 1A by $84 million, and it reduces the relative cost of a 2019 (Option 2) lease termination to approximately $170 million more than Option 1A – a drop of nearly 50%. He added that removing the allegedly flawed end-effect analysis and simply assessing I&M's application through the 2016-2045 analysis period indicates that Rockport Unit 2 is unlikely to be a reasonable and prudent decision over the extended period. He said this means that, even under I&M's optimistic scenario, Rockport Unit 2's SCR is likely to become a stranded asset – either absorbed by ratepayers or litigated with the lessors in 2022.

Mr. Fisher also claimed that I&M relied on outdated inputs by using fuel and capacity price forecasts. He testified that the instant case before the Commission was filed on October 20, 2016, meaning that an updated forecast, completed in October 2016, would have been available to I&M within days of the filing. He said a delay in filing by a few days could have resulted in a substantially different finding by I&M. Mr. Fisher contended it would not be appropriate to only assess the Rockport Unit 2 SCR decision on the basis of I&M's "Lower Band" analysis and added that I&M's "Lower Band" and "Higher Band" fuel price forecasts are not useful for these types of resource decisions, because the simultaneous higher and lower movement of the gas and coal prices dampens the extent to which a decision is in ratepayers' favor or is a liability.

Mr. Fisher made rough adjustments to I&M's analysis to account for updated fuel prices, the cost of market energy procured to serve load, and the revenue from energy sold into the market. He said the impact of his natural gas price update is dramatic because it impacts the core decisions of I&M's analysis. He added that the lower gas prices, reflected in market prices, increase the relative merit of every option in which Rockport Unit 2 is not maintained over the long term. He stated that his adjustment makes it clear that the long-term maintenance of Rockport Unit 2 is unlikely to be favorable for I&M ratepayers. He added 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 exit the lease in 2022.

Mr. Fisher also criticized I&M's capacity price forecasts and compared the forecast to the results of PJM's Base Residual Auction. He proposed a forward capacity price at 60% of net Cost of New Entry ("CONE"), or $180/MW-day, recalling that CONE is a ceiling price, and has never previously been reached. He stated that his capacity price adjustment impacts Option 2A most substantially, reducing the cost of replacing Rockport Unit 2's capacity with market purchases for the interim 2019-2023 period. He said his capacity price adjustment impacts the other options as well, but to a lesser extent, because the replacement capacity envisioned here is roughly equivalent to the size of Rockport Unit 2. Mr. Fisher stated that with this adjustment in place, cumulatively to the other corrections, Options 2 and 2A are almost the same cost. He said Options 2 and 2A continue to show a substantial benefit against Option 1A (over $400 million). He recognized that, with his adjustments, Options 2 and 2A clear Option 1B by a benefit of approximately $50 million and stated that the analysis 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 Unit 2 are non-existent. He added that if the 2016 forecast is substituted in his analysis, Option 2A clears Option 1A by nearly $500 million and Option 1B by $160 million. Mr. Fisher calculated that investing in Rockport and maintaining the facility through the indefinite future will result in ratepayer losses of about $400 million—or a $700 million swing.

Mr. Fisher said I&M made several key analysis errors in the consideration of ongoing capital costs at Rockport Unit 2 prior to the years when the unit is assumed to retire, biasing I&M's analysis for building the SCR, even if the unit retires in 2022. He said the first error arises from a mismatch between an explicit I&M assumption and its execution with respect to ongoing capital. He said the second error seems to be a simple transcription error, in which I&M used the wrong series of numbers for ongoing capital carrying costs at Rockport Unit 2 in Option 2A. He applied the ongoing capital cost correction incrementally to the fuel price update discussed above and concluded that the 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. He stated that under this correction, Option 2 becomes slightly more favorable than Option 1B by $39 million. He added that 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 I&M's contention. Mr. Fisher also identified what he considered an error with respect to the disposition of shared unit costs between Rockport Unit 1 and Rockport Unit 2.

Mr. Fisher stated that I&M's analysis subjects I&M to substantial litigation risk by seeking to build what he referred to as a sub-standard SCR and planning for substantially reduced ongoing capital at Rockport Unit 2 prior to the expiration of the I&M's lease. Mr. Fisher argued that I&M's proposal exposes it to liability under the "Event of Default" lease provision and to a possible enforcement action for noncompliance with the consent decree. His analysis of this risk shrunk the cost differential between Options 1A and 1B. He stated that while I&M portrays Options 1A and

1B as lower cost and maintaining optionality, his results indicate that I&M's outdated analysis fails to convey the tangible costs and risks associated with maintaining Rockport. He added that 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. He concluded that while the costs of simply building an appropriate SCR and maintaining Rockport Unit 2 are relatively smaller than his view of the potential litigation risk penalties, they are large enough alone to render the decision to retrofit uneconomic and ill-considered.

Finally, Mr. Fisher argued that I&M artificially weakened the robustness of the analysis by overpricing reasonable alternative energy options. He stated that using his updated renewable costs assumptions results in Option 2 being more cost-effective relative to Option 1B, and being Option 1B more cost-effective relative to Option 1A.

Mr. Fisher found that Rockport Unit 2 is not a reasonable long-term resource and under current projections is likely to become a sizable liability to I&M ratepayers. He testified that when I&M's analysis is updated, Option 1A (installing the SCR and renewing the lease) is not cost-effective under reasonable assumptions. He described and executed four sequential adjustments to I&M's analysis: the removal of an erroneous end-effects calculation, updating a year-and-a-half old fuel price forecast relied upon by I&M, correcting I&M's mistakes in the calculation of ongoing capital costs, and recommending a capacity price forecast more consistent with known market behavior. He stated that his adjustments substantially impact the decision to proceed with the SCR against other options examined by I&M. He stated that it becomes immediately apparent through this series of adjustments that the option to install the SCR and maintain Rockport past 2022 is neither viable nor reasonable under current market conditions. He added that even I&M's own analysis indicates that Rockport Unit 2 has a negative value if maintained past 2022. He concluded that his assessment of the Rockport Unit 2 SCR indicates that the prompt divestment from Rockport Unit 2 ahead of the SCR requirement is beneficial for I&M's customers and provides a known, low-risk exit from the power plant.

Mr. Fisher recommended the Commission deny the CPCN on the basis that neither of the options examined by I&M for the installation of SCR are least-cost or least-risk for ratepayers. He added that the Commission should require that I&M expediently file a plan for the replacement of the capacity and energy requirements otherwise met through Rockport Unit 2.

Mr. Fisher testified that 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 I&M maintain separate accounting for the cost of the SCR and that the Commission maintain the ability to adjust the rider at any time prior to 2019; (b) that I&M conduct, prior to signing a notice to proceed or other release to major SCR contractors, an updated analysis and present it to the Commission for review by April 2017; (c) that Joint Intervenors be afforded an opportunity to review and comment on such analysis by October 2017; (d) that the Commission retain the opportunity to hold back future funds if it is determined that I&M has proceeded against the best interests of ratepayers; (e) that I&M 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; (f) that I&M

shareholders bear full responsibility for all litigation fees and penalties resulting from any non-compliance with the consent decree; (g) that I&M shareholders bear full responsibility for all litigation fees and penalties from any contract breach; (h) that I&M be restricted to recovery of a fixed percentage deadband around the $137.1 million capital estimate for the SCR; and (i) 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.

11. I&M's Rebuttal Evidence. Mr. Chodak presented I&M's general reply to the OUCC and the Industrial Group's recommendations. He stated that he was pleased that Mr. Rutter corroborates I&M's view that I&M should proceed with retrofitting Rockport Unit 2 with SCR technology and not retire the unit at this time. He recognized that Option 1A in Mr. Weaver's economic analysis assumes that the Unit 2 lease will be renewed and that various factors impact the renewal decision, including market conditions, environmental regulations and the customer impact. He said I&M is working diligently on a resolution of the lease renewal. He stated I&M has and will continue to conduct a robust analysis regarding Unit 2, including modeling of replacement generation based on an assumption that the Rockport Unit 2 lease terminates at its scheduled date of December 2022. He said I&M will keep stakeholders apprised of its analysis as part of the 2018 IRP stakeholder process which will commence in the first quarter of 2018. He added that should a material development occur before then, I&M will update the Commission, the OUCC, and Joint Intervenors regarding the development as soon as practicable.

Mr. Hendricks testified that while he agreed with Ms. Armstrong that the CSAPR, the consent decree, and the NAAQS for ozone all contain requirements that could impact the allowable level of NOx emissions at the Rockport units, she has omitted the 2012 fine particulate standard and the US EPA obligation to review that standard. He said that in addition, US EPA has used the "good neighbor" provision in Section 110 of the clean air act to impose additional emission reduction obligations on large sources of NO_x and SO_2 emissions, like the Rockport units, in an effort to achieve and maintain the NAAQS in downwind areas far from the emitting units. He said the CSAPR is an example of this type of requirement. He added that while I&M may be able to achieve compliance with its current CSAPR obligations without operating the Rockport Unit 2 SCR, I&M will likely have to secure additional ozone season NO_x allowances from the market. He said installing the SCR on Rockport Unit 2 will provide important compliance flexibility to I&M in the event that there is an increase in market prices for allowances, a decrease in state ozone season NO_x budgets, or an increase in plant ozone season NO_x emissions. He testified that while I&M has not done an economic analysis to quantify this benefit due to the fact that the Rockport Unit 2 SCR installation is a requirement under the consent decree, it is nonetheless a benefit to I&M's customers.

Mr. Williamson verified Mr. Rutter's calculation and assertions regarding the estimated rate impact of terminating the Rockport Unit 2 lease. He said the OUCC correctly found that the cost to customers for approval of the CPCN to be less than the cost to customers associated with termination of the lease. With respect to Mr. Blakley's concerns, Mr. Williamson testified that his direct testimony simply summarized the accounting that occurs upon retirement of any capital asset according to the FERC USoA and that any remaining costs or undepreciated book value resulting from retirement would be included in future I&M filings until fully recovered through the ratemaking process. He said it has long been established that the remaining book value of investments that were once used and useful in the provision of service to customers are recoverable through the ratemaking process regardless of whether they are fully depreciated at the time of retirement. He added that he did not believe that a base rate case is the only type of proceeding that may be appropriate for the Commission to address remaining net book value of a retired asset. He noted as an example I&M's standalone proceeding in Cause No. 44555 to address the closure of the Tanners Creek Plant, including its remaining net book value, which the OUCC and the Commission found to be reasonable.

Mr. Chodak disagreed that I&M has not been assessing its options. He said I&M's IRP analysis, as well as the modeling presented in this case, support the conclusion that the Rockport SCR Project is the preferred option. He said the special contingency plan Mr. Phillips asks the Commission to require I&M to produce is unnecessary. He added that as circumstances develop regarding the lease, I&M will make filings with the Commission outside of the IRP process to the extent necessary or appropriate. He responded to Mr. Phillips's remarks regarding the five year "rule of thumb" to bring a new CCGT online. He explained that if I&M's IRP preferred near-term action plan includes a new CCGT, I&M would meet its customers' need for energy and capacity through existing generation and market purchases until the new facility could be completed. In response to Mr. Phillips's contention that I&M does not have a long-term lease arrangement past December 7, 2022, Mr. Chodak clarified that the lease provides I&M a unilateral right to renew the lease at a fixed rate payment. He said this is not a situation where the lessor and the lessee must mutually agree to the lease renewal. Mr. Chodak stated that while reliance on the market exposes I&M and its customers to price risk, that price risk can be managed through bilateral transactions. He testified that should I&M need to rely on market purchases to replace the Unit 2 generation, he is confident that I&M is capable of managing a need to engage in market transactions should that be the best path forward for I&M and its customers.

Mr. Chodak disagreed that a decision regarding the lease is overdue. He said I&M has proceeded diligently to pursue the reasonable least-cost options for its customers, including the successful renegotiation of the consent decree. He said that in doing so, I&M achieved significant optionality in the face of great uncertainty regarding environmental regulation and market conditions and reduced the near-term cost of its environmental compliance at Rockport by hundreds of millions of dollars for the benefit of customers.

Mr. Chodak and Mr. Williamson disagreed with the Industrial Group's proposed cost recovery limitations, explaining that it is well established that the remaining book value of a retired unit of property that was once used and useful is recognizable in the ratemaking process. Mr. Chodak explained that the Industrial Group's proposed cost disallowance is also inconsistent with the pre-approval process, which was created to assure cost recovery, not limit it.

Mr. Chodak further explained why the Industrial Group's proposal to cap the Rockport SCR Project costs recoverable in the rider at I&M's current estimate is unnecessary and could have unintended consequences. He explained that the statutory framework and Commission practice allow for ongoing review of a project's status and costs in the rider proceedings, which allows for timely review of the construction and of any changes in the estimated Rockport SCR Project cost. He explained the SCR cost estimate is based on a thorough analysis of the activities, materials and supplies, and labor associated with the Rockport SCR Project. He testified the cost estimate reflects the best information available at the time of the analysis, including experience with the costs of similar projects at other coal-fired facilities. He said while I&M remains confident in its SCR cost estimate, he disagreed that the circumstances in this case warrant a departure from the Commission's ongoing review practice.

Mr. Chodak and Mr. Williamson explained why I&M's proposed ten-year depreciation rate is reasonable and why Mr. Phillips's recommended 28- or 20-year depreciation rate is not. Mr. Williamson explained that there is no reasonable basis for a 20-year depreciable period and that a ten-year depreciable period strikes a reasonable balance between the uncertainty associated with the remaining lease term and what the useful economic life of Rockport Unit 2 may be.

Mr. Williamson agreed with the Industrial Group's recommendation that I&M should allocate any Commission-approve fixed production costs to the customer classes using the 6 CP method from I&M's most recent rate base. He said that once I&M receives an order in a future basic rate case, it would allocate any Commission-approved fixed production costs to the customer classes based on the production demand allocator approved by the Commission in that case.

Mr. Chodak explained that Mr. Fisher has failed to identify sufficient reason to derail this proceeding and doing so places I&M's customers at risk. Mr. Chodak testified that I&M's analysis considers the potential for both low and high gas and energy price forecasts based upon the information available at the time its case was prepared. He said Mr. Fisher point out that a more recent forecast has become available during the period of time this case has been pending. He added that it is usually the case that new information will become available. He said that alone does not mean that a decision should be delayed or this proceeding extended. He added that updating the economic analysis and allowing time for input is a time-consuming matter, and if I&M were to pursue Mr. Fisher's recommended process, the deadlines regarding the SCR and lease expiration would draw nearer and all the while new information, both actual and forecast, would continue to become available. Mr. Chodak testified that the relevant question is not whether new information has or will become available. Rather, the issues are whether or not I&M has better information today that warrants a delay in making a decision and do the potential costs and risks of that delay outweigh the potential benefit of having more time to make the decision.

Mr. Chodak's judgment is that there is no potential benefit that outweighs the costs and risk of delaying the Rockport SCR Project. He added that while natural gas and other market prices may affect longer-term disposition decisions regarding Unit 2, in the near term the installation of the SCR is the reasonable least-cost path forward even if the lease is ultimately terminated in December 2022. He said not installing the SCR means that I&M will need to terminate the lease early because the unit could not be operated in compliance with environmental requirements. He stated that this would subject I&M and its customers to a lease termination payment that significantly exceeds the cost of the Rockport SCR Project. He said it will also remove the optionality provided by the Rockport SCR Project.

Mr. Chodak explained that I&M understands its obligations under the lease to keep the plant in working order and decades of experience show that I&M has complied with the lease. He said I&M has every intention of fulfilling that obligation even in the scenario where I&M returns the unit to the lessors in 2022.

Mr. Chodak and Mr. Weaver explained that while there was an inadvertent error in the level of capital "tapering" in the modeling presented by Mr. Weaver, when the modeling is corrected, the proposed Rockport SCR Project remains the relative least-cost alternative.

Mr. Hendricks and Mr. Pifer refuted Mr. Fisher's contention that I&M is proposing to build a substandard SCR. Mr. Hendricks testified that the consent decree does not include any unit-specific NO_x emission rates or limitations. He said instead, the consent decree includes annual tonnage limitations for NO_x on a system-wide level for the entire AEP eastern system, which includes the plant and other affiliated units. AEP and its affiliates specifically sought these system-wide limits because they provide significant flexibility to meet the conditions of the consent decree in an economic manner. Mr. Hendricks testified that the consent decree does not provide any definition or reference to a "standard" SCR and added that Mr. Fisher's claim that I&M's proposed SCR design for Rockport Unit 2 is "sub-standard" is conjecture and not based on the requirements of the consent decree. Mr. Hendricks explained that the consent decree defines an SCR as "a pollution control device that employs selective catalytic reduction technology for the reduction of NO_x emissions." He said that the design of the Rockport Unit 2 SCR, as conveyed by Mr. Pifer, complies with the requirements of the consent decree. He added that I&M's Rockport SCR Project is a pollution control device that will reduce NO_x emissions from Rockport Unit 2 through selective catalytic reduction technology. During cross-examination, Mr. Chodak confirmed that the Rockport SCR Project would install what is defined as an SCR under the terms of the consent decree.

Mr. Hendricks provided the full definition of "continuously operate" contained in the consent decree and stated that I&M will operate the Rockport Unit 2 SCR in accordance with the consent decree's definition to continuously operate and in accordance with the system-wide NO_x tonnage limits. He added that I&M's compliance with the consent decree's requirement to continuously operate is independent of the SCR system's design.

Mr. Pifer explained that the SCR that I&M is proposing to install on Rockport Unit 2 is by no means "sub-standard" but is based on reliable technology and sound engineering principles. He said the proposed SCR, which is identical in design to the SCR that the Commission has already approved for Rockport Unit 1, will reduce NO_x emissions at Unit 2. During cross-examination, Mr. Pifer explained that the contract I&M has with Riley Power includes a performance guarantee that calls for the SCR performance at the beginning of the installation period to achieve an 88% reduction in NO_x emissions. He stated this performance guarantee is based on a 16,000-hour cycle, so over time as the catalyst wears out, there will be less and less removal, but that at the end of the guarantee period, the guarantee is 50% reduction. However, he also stated the catalyst management plan calls for 70% removal and that he does not expect to go below that level of removal. He further testified that I&M's plan to operate the SCR initially with two catalyst layers is tailored to the unique design features of the plant and will allow the SCR to operate effectively to reduce NO_x emissions without the costly investment that would be required to operate the SCR immediately with four layers.

Mr. Pifer discussed the catalyst function in the SCR and disagreed with Mr. Fisher's contention that the NO_x emission reduction from the SCR is substantially smaller in magnitude than that achieved by other contemporary SCR systems. Mr. Pifer stated that what Mr. Fisher fails to explain is that NO_x emission reductions from SCR technology depend on a number of variables that may vary from plant to plant. For instance, Rockport Units 1 and 2 predominantly burn low-sulfur PRB coal, which typically has a higher moisture content and which results in a lower combustion temperature. He said that due to this lower combustion temperature, less NO_x is produced at Rockport than at other units that largely consume eastern bituminous coal as their fuel source. He testified that as explained in his direct testimony, Rockport Unit 2 is already equipped with conventional combustion controls to reduce the formation of NO_x, including low NO_x burners and overfire air. He stated that based on these unit-specific characteristics, it is misleading to compare I&M's expected NO_x reduction from the proposed Unit 2 SCR design against other coal-fired units' NO_x reduction performance. Mr. Pifer expanded on this explanation in response to Joint Intervenors' cross-examination, noting among other things that the US EPA document Mr. Fisher quoted acknowledges this point.

Mr. Pifer explained why I&M does not propose to install the fan capacity to accommodate filling four layers of the catalyst and added that it is not cost effective or necessary to include the additional fan capacity to comply with the consent decree. Mr. Pifer testified that the Rockport Unit 2 SCR design meets the definition of SCR as defined in the consent decree because it is a pollution control device that will reduce NO_x emissions from Rockport Unit 2 through selective catalytic reduction technology. Through his rebuttal testimony and testimony elicited during cross-examination, Mr. Pifer established that I&M proposes to install a fully complete SCR system for Unit 2 that will effectively and immediately reduce NO_x emissions in the same way as the SCR that has already been approved for Unit 1. Mr. Pifer stated that the Rockport SCR Project has the capacity to hold four catalyst layers and if the FGD is installed on the unit, with the additional corresponding fan capacity that is required of an FGD installation, the SCR will be able to operate with all four catalyst layers. Pointing to Mr. Hendricks's testimony that there are many regulations affecting Rockport Unit 2, which could require additional NO_x emission reductions in the future, Mr. Pifer stated that if such reductions are required, I&M will have options to achieve them economically, and preserve the value of the SCR investment subject to this proceeding. Mr. Pifer concluded that the SCR design that I&M has proposed for Rockport Unit 2 satisfies the definition of an SCR included in the consent decree, and will contribute reductions necessary to maintain compliance with the AEP eastern system caps, as explained by Mr. Hendricks. Mr. Pifer added that this SCR is designed to accommodate four catalyst layers, and could more cost effectively achieve even greater NO_x reductions at the time the unit is equipped with an FGD system. He concluded that the installation of the SCR system included in this proceeding allows I&M to satisfy its obligations under the consent decree at the lowest reasonable cost to customers.

Mr. Chodak testified that Mr. Fisher's litigation risk argument is conjecture. He said I&M regularly assesses and manages risk and in doing so, considers potential threats as well as the costs and risk of implementing measures to address the potential vulnerability. Mr. Chodak stated that Mr. Fisher identifies a possible loss, but fails to adequately assess the probability of the loss or the cost/benefit of avoiding the potential threat by pursuing a different course of action. He disagreed that there is substantial risk of a lease default or violation of the consent decree that warrants the rejection of the Rockport SCR Project.

Mr. Karl R. Bletzacker, AEPSC Director, Fundamentals Analysis, and Mr. Weaver refuted Mr. Fisher's contention that I&M's analysis is stale or otherwise unreasonable. Mr. Bletzacker explained that the forecast used by I&M was I&M's most up-to-date fundamentals forecasts available at the time Mr. Weaver performed his analysis and added that it would have taken more than a few days to complete an analysis using the subsequent forecast. Mr. Bletzacker explained that the fundamentals forecasts is not created to meet a specific regulatory need in a particular jurisdiction; rather, it is distributed ubiquitously across all AEP operating companies after completion. He said it may also be referenced by AEP for other purposes which include fixed asset impairment accounting, capital improvement analysis, and strategic planning. He explained that the length of time between fundamentals forecasts can vary widely depending on complexity and added that as such, there is no set timetable for its release. He stated that downstream consumers, such as Mr. Weaver, are directed to the contemporaneous fundamentals forecasts.

Mr. Bletzacker defended the reasonableness and reliability of I&M's long-term North American energy market forecast (referred to herein as the "fundamentals forecasts"). He disagreed that Mr. Fisher's comparison of the first year natural gas prices used in I&M's analysis to 2016 actuals shows the fuel prices in the analysis are outdated. Mr. Bletzacker explained that the comparison is erroneous because the fundamentals forecasts values are weather normalized and the actuals are not. Mr. Bletzacker went on to provide examples of how and why this makes a difference. He also explained why I&M's forecasted prices are not as low as the NYMEX commodities market and testified that the futures market is not relied on for long-term energy market forecasts.

Mr. Bletzacker also disagreed with Mr. Fisher's contention that the subsequent 2016 fundamentals forecast has substantially different data than what was used in I&M's filing. Comparing I&M's 2015 and 2016 fundamentals forecasts, Mr. Bletzacker testified that generally, and except for adjustments due to the effects of actual weather in 2016 of weather-normalized values determined in 2015, the forecasts for Henry Hub natural gas, PRB coal and AEP Gen Hub on- and off-peak electric energy prices are similar. Mr. Bletzacker stated that a notable difference and the primary driver of the 2016 fundamentals forecasts was the approach taken to potential CO_2 mitigation policy and went on to explain this difference in the two forecasts. He said it is reasonable to conclude that, from the perspective of CO_2 mitigation policy and due to the present-day political environment, the 2015 fundamentals forecasts used by Mr. Weaver has more merit. He also stated most importantly, that both fundamentals forecasts are within a band of credibility that is supported by justifiable assumptions that are applicable today.

Mr. Bletzacker also rebutted Mr. Fisher's replacement of I&M's established long-term fuel, energy, and capacity values. Mr. Bletzacker explained that in contrast to Mr. Fisher's spreadsheet quality analysis, I&M's fundamentals forecasts utilizes the AuroraXMP Energy Market Model, which is the most comprehensive and reliable electricity forecasting and analysis tool available. He stated that the process used to develop the commodity prices in I&M's forecast relies on rigorous modeling, which produces a market forecast where the components are "fitly-joined" and synchronized. He said Mr. Fisher's targeted and simplistic replacement of I&M established long-term natural gas and energy prices is unreasonable because the values Mr. Fisher used are indifferent to the correlative effects on other salient forecast elements. Mr. Bletzacker stated that the natural gas and energy prices are simply not menu items that can be ordered "a la carte" because it defeats this valuable and necessary synchronization. He added that by focusing only on lower natural gas and energy prices, Mr. Fisher ignores the possibility that commodity prices may be higher and pointed out that OUCC witness Mr. Rutter recognized factors which could lead to higher natural gas prices. Mr. Bletzacker noted that I&M considered an array of five unique, fundamentals forecasts scenarios to account for a reasonable range of future outcomes. He said Mr. Fisher's approach lacks this robustness.

Mr. Bletzacker also discussed the Energy Information Administration's Annual Energy Outlook ("EIA AEO"). He acknowledged that the EIA AEO relies on rigorous modeling but explained that the components of the EIA AEO forecast are not interchangeable with I&M's fundamentals forecast. Mr. Bletzacker pointed out that the EIA AEO warns that its projections are not predictions of what will happen. Rather, the EIA AEO forecast represents modeled projections of what may happen given certain assumptions and methodologies. Mr. Bletzacker stated that Mr. Fisher's comparison of the fundamentals forecasts to the EIA AEO reference case and his simplistic replacement of I&M established inputs are erroneous and misleading. Mr. Bletzacker concluded that Mr. Fisher's targeted replacement of natural gas and energy prices alone, without integrating the effects of that replacement on other forecast elements, masks potentially critical final outcomes.

Mr. Bletzacker also disagreed that I&M's fundamentals forecasts' projections of capacity prices are deficient and should be replaced by some fractional value of CONE. He explained that I&M's model-driven projections of capacity prices and energy prices are inextricably linked and stated that capacity values represent the non-energy revenue necessary for the least dispatched units to remain viable and for the entire fleet to meet required reserve margins. He said consequently, capacity values, combined with expected energy margins, must approach the CONE. He explained that the current three-year PJM Base Residual Auction ("BRA") capacity prices may not offer enough assurance to be reflective of long-term capacity prices. He added that as a result 1) new generation facilities will not be built or, 2) market energy prices will rise dramatically to provide sufficient revenue to justify the investment. He testified that the model-driven capacity price forecast requires capacity levels within PJM to match its target reserve margin. He stated that Mr. Fisher's selection of an arbitrary fractional value of CONE violates this necessary linkage and therefore yields results that are not consistent with market fundamentals.

Mr. Bletzacker explained that the fundamentals forecasts do consider diverse sources of licensed and publicly available research information, which includes PJM and others. He added that the fundamentals forecasts do reflect the PJM BRA capacity value results available at the time the fundamentals forecasts are released. He pointed out an inconsistency in Mr. Fisher's contentions. Mr. Bletzacker noted that Mr. Fisher observed that the capacity auctions results should have been utilized by Mr. Weaver. Mr. Bletzacker pointed out that Mr. Fisher's contention conflicts with his observation that the first four years of the analysis are irrelevant because the market purchases and sales from 2016 to 2019 are identical across all cases.

Mr. Weaver explained what end-effects are and why end-effects should continue to be reflected as a component of the Rockport Unit 2 disposition analysis. He disagreed with Mr. Fisher that I&M had selectively chosen which costs to include, or exclude, from the end-effects period. He explained that as demonstrated within its filed workpapers, all cost and revenue-contribution categories that were considered and reported directly by the modeling through the 2045 planning period was also incorporated into the end-effect calculations summarized by I&M, for all option alternatives evaluated. He stated that this analysis and consideration of end-effects is appropriately included in such sound planning evaluations. He added that in this context we do not short-change the life of a gas unit; therefore it would be inappropriate to short-change the potential life of Rockport Unit 2. He testified that there is a reasonable prospect that costs and revenues associated with the Rockport Unit 2 disposition alternatives could continue well beyond 2045, and this post-2045 cost and revenue could properly influence the relative option-to-option results. He added that this is relevant in a unit disposition analysis such as this that assesses options that have unique and varying resource life cycles. For instance, he explained that Option 1B and Option 2, as defined in his direct testimony, indicate that replacement resources—including modeled natural gas combined cycle units—would begin operation in 2023 and 2020, respectively. He stated that since the projected operating life of a combined cycle could be 30-40 years or longer, it could readily exceed the fixed model optimization end-date of 2045. He testified that recognizing that Rockport Unit 2 was placed into service in 1989, which is recent compared to other coal-fired generating units, it is appropriate for Option 1A (also defined in his direct testimony) to consider that Unit 2 could provide generation service after 2045. Mr. Weaver discussed information from the EIA AEO which supports the view that it is reasonable for planning purposes to consider the potential for the relatively young and efficient Rockport Unit 2 to continue to operate after 2045. He clarified that conducting this planning analysis does not commit I&M to this path forward and added that the SCR retrofit is a reasonable least-cost plan even if the future unfolds in such a way as to necessitate an earlier retirement of the unit.

Mr. Weaver noted that Kentucky Power's Big Sandy Unit 2 is significantly older than Rockport Unit 2 (i.e., 20 years older). He explained that his analysis of a 2011 retrofit for this older unit was reasonable and added that the circumstances for the Rockport Unit 2 are different. At the end of the optimization period the Big Sandy unit would have been over 70 years old, while the Rockport unit would only be approximately 56 years old at this point.

Mr. Weaver disagreed with Mr. Fisher's view that all end-effects costs and revenues should be disregarded. Mr. Weaver explained that in the case of Option 1A, over $830 million in on-going capital expenditures were forecasted at Rockport Unit 2 over the 2016 through 2045 time period. He explained that those ongoing capital expenditures are recognized in the form of subsequent recovered annual carrying charges over a forward period, some of which extend beyond 2045. He stated that the elimination of the recovery of those capital carrying costs that occur after 2045 would incorrectly bias the analysis for Option 1A. He added that the failure to consider PJM market energy revenue generated by the unit after 2045, given the typical larger energy margins/spreads available to an efficient coal unit, would simultaneously bias against Option 1A. He stated that I&M's economic analysis considered both of these end-effects. He added that if end-effects costs were simply ignored, other factors such as CO_2 costs that would be incurred by Rockport Unit 2 after 2045 would also be eliminated from economic consideration. He added that this would introduce even more of a relative benefit to Option 1A and thus made the point that such relative higher incremental CO_2 costs were fairly reflected as a component of the end-effects cost captured in I&M's modeling in this filing.

Mr. Weaver further responded to the claim that ongoing capital expenditures and attendant carrying costs should have been considered beyond the 2045 modeling period. Any impact on the CPW results would be small due to the significant discounting of such out-year carrying costs to current present dollars reflected in CPW.

Mr. Weaver explained that I&M's modeling of end-effects in this case was performed consistently with the analysis of the Rockport SCR Project offered in Cause No. 44523. He concluded that Mr. Fisher's recommended adjustments to the study period CPW costs by simply eliminating the calculated end-effects cost and revenues is unwarranted based on the fact that the determination of such impacts is an essential aspect of the inherent disposition optimization modeling performed and relied upon.

Mr. Weaver acknowledged the transcription error noted by Mr. Fisher and stated that, when corrected, the ongoing capital costs for Option 2A should have resulted in a CPW that was $28.3 million lower. He also concurred that the tapering of on-going capital cost for Option 1B did not follow the expressed assumption in his filed workpaper. He stated had that assumption been followed, it would have resulted in a CPW cost for Option 1B that was $52.4 million higher. He revised his analysis to reflect these corrections. He stated that although slightly less beneficial than I&M's original evaluation, the relative cost differences would indicate that Option 1A would continue to be the relative least-cost alternative. He also included a comparative analysis regarding Option 1B. He explained that although slightly less beneficial than I&M's original evaluation, the relative cost differences would indicate that Option 1B continues to be the relative least-cost alternative when compared to either of the Option 2 alternatives that would not install an SCR, but rather would return the unit to the lessor in December 2019, triggering a $715.7 million lease termination value payment. He stated that his conclusion remains the same as with his direct testimony that Option 1A continues to be the relative least-cost alternative, even with the correction made to the treatment of on-going capital costs. He added that the "modified" view presented in his rebuttal testimony also corroborates I&M's earlier determination that both of the retrofit options (Options 1A and 1B) are lower relative cost alternatives to either of the Option 2 alternatives that would not install an SCR.

Mr. Weaver refuted Mr. Fisher's recommendation 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. Mr. Weaver explained that I&M has assessed incremental energy efficiency, as well as both wind and solar resources as part of a process to ensure greater resource diversity, a process that was primarily informed by the evaluations performed within its IRP. He explained that I&M's economic modeling appropriately employed the most recent and pertinent renewable resource cost information available to I&M at the time the modeling was conducted and explained why wind and solar resources can only be considered a viable capacity disposition alternative for Rockport Unit 2 to a limited degree.

Mr. Weaver explained that Mr. Fisher predicated all of his recommended adjustments to I&M's modeled CPW from the "BASE" commodity price forecast. Mr. Weaver pointed out that this BASE forecast included a carbon tax assumption starting in the year 2022 and continuing in perpetuity. Mr. Weaver stated that Mr. Fisher did not discuss or opine on his view around the prospects that the EPA's CPP at attendant CO_2 emission regulation of existing fossil-fired facilities may be reduced under the new presidential administration. Mr. Weaver also noted that Mr. Fisher did not perform any sensitivity around a "No Carbon" pricing view even though I&M's analysis of this sensitivity were available to Mr. Fisher and showed that the relative benefit of Option 1A increased by $163 million versus Option 2.

Mr. Weaver disagreed with Mr. Fisher's assertions that the optionality of Option 1B is not reasonably established and the long-term benefits of maintaining Rockport Unit 2 are non-existent. Mr. Weaver showed that even if one was to include Mr. Fisher's proposed "litigation risk" adjustment, the analysis shows the optionality associated with the continued operation of Rockport Unit 2 confirms Option 1A as being the relative least-cost alternative.

Mr. Weaver testified that while Mr. Fisher relied solely on the "BASE" pricing, I&M's modeling utilized a suite of long-term commodity price forecasts as part of its modeling process. He stated that the relative results for Options 1B and 2 in the "Lower Band" analysis was comparable to the BASE pricing scenario. He further stated that Mr. Fisher essentially ignored I&M's "Lower Band" commodity pricing analysis.

Finally, Mr. Weaver stated the methodology Mr. Fisher used is not reasonable and explained a primary error in Mr. Fisher's analysis is that he failed to perform an appropriate economic dispatch when developing his gas price CPW cost adjustment. Mr. Weaver showed that if Mr. Fisher had employed some type of economic dispatching tool, his analysis would produce unreasonably low capacity factors for Rockport Unit 2. Mr. Weaver explained that this in turn suggests that the pricing employed in Mr. Fisher's analysis is flawed. Mr. Weaver added that when economic dispatch is used with Mr. Fisher's natural gas and energy pricing adjustments, the capacity factor output for the new combined cycle units increased as would be expected. Mr. Weaver added that when corrected, Mr. Fisher's analysis suggests that the installation of the SCR is the relative least-cost alternative versus Option 2. He explained that given the relative certainty of the lease termination value payment in Option 2 as well as the cost upside risk of Option 2A by virtue of being potentially dependent on the PJM market for as much as 1,100 MW of replacement capacity and energy resources for that interim 2020 through 2022 "pre-build" period, from a planning perspective Option 2A should not be considered the optimal resource path for I&M, even under the set of unwarranted natural gas and energy pricing profiles suggested by Mr. Fisher. Mr. Weaver added that it is also important to realize that, given the broad timeframe and range of variables considered as part of long-term asset economic evaluations such as this, it is not uncommon that all sensitivities and scenarios would not produce the same result. He stated that in this case it is the judgement of I&M that the Rockport SCR Project (Options 1A or 1B) on the weight of the information examined is the best option.

Mr. Chodak explained that Mr. Fisher's proposed CPCN conditions go far beyond what is contemplated by the pre-approval process and depart from Commission practice. He stated I&M needs to know whether or not the SCR retrofit is approved within a timeframe that will allow I&M to construct the SCR if approved or to develop an alternative plan if rejected. He said the request for a Commission decision is consistent with the governing statutory framework, which contemplates "pre-approval", not "preliminary" approval. He added that if adopted, Mr. Fisher's additional and protracted process would burden and cloud the SCR implementation and potentially delay construction such that the SCR would not be in-service by December 2019. He said that because the additional process Mr. Fisher seeks would create uncertainty it would also burden, if not delay, the Unit 2 lease negotiations and renewal analysis.

Mr. Chodak testified that the Commission should decline Mr. Fisher's invitation for the Commission to insert itself into the lease negotiations. Mr. Chodak testified that I&M proposes to keep the Commission and stakeholders informed of matters regarding the Rockport Unit 2 lease. He said it is premature to determine what and when additional process should occur with the Commission but clarified that I&M would come to the Commission for approval of any decision to renew or otherwise extend the lease.

Mr. Chodak stated that Mr. Fisher's proposed percentage deadband should be rejected for the reasons set forth in his response to Mr. Phillips's proposed cap. Mr. Chodak added that the ongoing review process should be used to review costs and changes (if any) in the capital cost estimate for the Rockport SCR Project.

Mr. Chodak stated that I&M has and will continue to make decisions in the best interest of its customers to remain one of the lowest cost providers in the State of Indiana. He noted that the OUCC and the Industrial Group recognize the need for the Rockport SCR Project. He concluded that the litigation risk issues raised by Mr. Fisher do not support the rejection of the Rockport SCR Project and the delay or additional regulatory process he seeks is not warranted.

12. Commission Discussion and Findings. I&M requests a CPCN under Ind. Code ch. 8-1-8.7 for approval of the Rockport SCR Project. I&M seeks cost recovery for the Indiana jurisdictional portion of the I&M ownership share and associated accounting and ratemaking treatment in accordance with the Commission's authority under Ind. Code § 8-1-8.8-11 and related statutes and regulations, including authority to depreciate I&M's ownership share of the Rockport SCR Project over a ten-year period in accordance with Ind. Code § 8-1-2-6.7. Finally, I&M requests ongoing review of the Rockport SCR Project in accordance with Ind. Code § 8-1-8.7-7.

A. CPCN. In its Petition, I&M sought a CPCN for I&M's Ownership Share of the Rockport SCR Project under Ind. Code ch. 8-1-8.7 and accounting and ratemaking in accordance with Ind. Code ch. 8-1-8.8 and related statutes and rules.

(i) Indiana Code ch. 8-1-8.7 - CPCN. CCT is defined in Ind. Code 8-1-8.7 as:

> [A] technology (including precombustion treatment of coal): (1) That is used in a new or existing electric generating facility and directly or indirectly reduces airborne emissions of sulfur or nitrogen based pollutants associated with the combustion or use of coal; and (2) That either: (A) Is not in general commercial use at the same or greater scale in new or existing facilities in the United States as of January 1, 1989; or (B) Has been selected by the United States Department of Energy for funding under its Innovative Clean Coal Technology program and is finally approved for such funding on or after January 1, 1989.

Mr. Pifer explained that SCR is a proven, reliable technology used by AEP and others throughout the electric utility industry to directly reduce NO_x emissions from coal-fired generating units. Mr. Pifer testified that this technology was not in general commercial use at the same or greater scale in the United States as of January 1, 1989. The Commission's Order in *Southern Indiana Gas and Electric*, Cause No. 41864 (IURC 8/29/2001) reached the same conclusion, noting that SCR technology was selected by the U.S. Department of Energy for funding under its Innovative Clean Coal Technology Program and was finally approved for such funding on or after January 1, 1989. In Cause No. 41864, the Commission found that SCRs reduce airborne emissions of nitrogen-based pollutants associated with the combustion of coal and concluded that SCR technology constitutes CCT as defined in Ind. Code §§ 8-1-2-6.6 and 8-1-8.7-3. The record here supports the same conclusion. Accordingly, we find that the Rockport SCR Project constitutes CCT pursuant to Ind. Code § 8-1-8.7-1.

Under Ind. Code § 8-1-8.7-4(b), to issue a CPCN, the Commission must:

(1) make a finding that the public convenience and necessity will be served by the construction, implementation, and use of clean coal technology;
(2) Approve the estimated costs;
(3) made a finding that the facility where the clean coal technology is employed:
A. Utilizes and will continue to utilize Indiana coal as its primary fuel sources; or
B. Is justified, because of economic considerations or governmental requirements, in utilizing non-Indiana coal; after the technology is in place; and
(4) Make a finding on each of the factors described in Ind. Code § 8-1-8.7-3(b), including the dispatching priority of the facility to the utility.

(a) <u>Factors of Ind. Code § 8-1-8.7-3(b)</u>. Ind. Code § 8-1-8.7-3(b) sets forth nine factors, each of which we will consider.

1. <u>The cost of constructing, implementing, and using the CCT compared to conventional emission reduction facilities</u>. I&M performed an analysis showing that the Rockport SCR Project will enable I&M to reduce NO_x emissions and comply with the consent decree. Mr. Weaver's analysis based on the assumptions employed demonstrated that the Rockport SCR Project is a cost-effective compliance option. The OUCC and the Industrial Group also presented testimony supporting SCR technology. Mr. Hendricks discussed the benefits of this choice of CCT. We find it is reasonable compared to conventional emission reduction facilities.

2. <u>Whether the CCT will also extend the useful life of existing generating facilities</u>. The record reflects that the installation of the SCR control technology will allow Rockport Unit 2 to continue to operate beyond the December 31, 2019 installation requirement in the consent decree. The record reflects that the installation of the CCT will preserve the remaining life of this unit. The SCR is a cost-effective option for customers and ensures the availability of necessary capacity and energy through at least December 2022. Therefore, we find that the proposed Rockport SCR Project will extend the useful economic life of Rockport Unit 2.

3. **The potential reduction of sulfur and nitrogen based pollutants achieved by the proposed CCT system.** The evidence demonstrates that the SCR technology will allow I&M to reduce its NO_x emissions. Mr. Pifer said I&M anticipates that the SCR will achieve an annual average NO_x emission rate of 0.15 lbs/MMBtu or less based on the current coal supply and air flow configuration of Rockport Unit 2. This performance is based on operation with catalyst installed in two or more layers and reconfigured air heater baskets, but no changes to the fan capacity of the unit. Mr. Pifer explained that installing additional fans as part of the Rockport SCR Project would be unnecessary and wasteful because if FGD systems are later added to the unit, those fans would need to be removed and replaced as part of the FGD installation.

Mr. Fisher contended that I&M is proposing to build what he called a "sub-standard" SCR and this in turn raises a risk of litigation under the consent decree and the lease. Mr. Fisher's contention that the proposed SCR is sub-standard rests on the premise that the proposed NO_x emission reduction is substantially smaller in magnitude than that achieved by other contemporary SCR systems. I&M has presented evidence that demonstrates that I&M's Rockport SCR Project is a pollution control device that will reduce NO_x emissions from Rockport Unit 2 through the use of selective catalytic reduction technology. The record also shows that I&M intends to operate the Rockport Unit 2 SCR in accordance with the consent decree's definition of continuously operate and in accordance with the system-wide NO_x tonnage limits in the consent decree.

Accordingly, we find that the NO_x emissions reductions from I&M's proposed Rockport SCR Project are reasonable and I&M's proposal would preserve flexibility to adjust to additional compliance requirements as they may unfold in the future.

4. **The reduction of sulfur and nitrogen based pollutants that can be achieved by conventional pollution control equipment.** The evidence demonstrates that reduction of air emissions through conventional technology would be insufficient to bring I&M into compliance with the consent decree and the several US EPA regulatory initiatives in various stages of development discussed by Mr. Hendricks. We find that conventional pollution control equipment cannot provide equivalent beneficial reduction of NOx emissions.

5. **Federal sulfur and nitrogen based pollutant emission standards.** As explained by Mr. Hendricks, NO_x emissions are regulated under the Clean Air Act. Additionally, as discussed by Mr. Hendricks, further NO_x emissions requirements are anticipated to be part of various pending US EPA regulatory initiatives. Accordingly, we find that federal emission standards have been appropriately taken into consideration.

6. **The likelihood of success of the Rockport SCR Project.** A key aspect of success in the case before us is dependent on whether the Rockport SCR Project allows the continued use of Unit 2. Mr. Pifer explained that SCR technology is currently being installed at Rockport Unit 1 and it has been successfully installed on 14 other AEP units, including four units similar in design to the Rockport units. He testified that AEPSC has a proven track record of successfully managing the design and construction of many major environmental retrofit projects and it is expected that the SCR installation at Rockport will be another success.

Furthermore, an important assumption put forth by I&M in support of the Rockport SCR Project is that it will be successful in avoiding any premature lease termination costs. The evidence indicates that this cost could be as high as $716 million.[3] In essence, the success of I&M's proposed solution avoids this cost associated with premature (in advance of 2022) lease termination because it will allow I&M the use of Rockport Unit 2 through the end of the current lease because the requirements of the consent decree are satisfied. Mr. Fisher expressed his concerns as noted above that the specific application and use of the proposed Unit 2 SCR may not successfully avoid this cost. Failure to successfully meet the current lease obligations with the Rockport SCR Project was a condition not considered by I&M in its economic analysis. I&M's experience with the SCR on Rockport Unit 1 meeting the requirements of the consent decree serves as a primary foundation of its confidence, a laid foundation the Commission affords significant weight. However, as a result of this confidence the risk of failure of the Rockport SCR Project to allow I&M the use of Unit 2 through 2022 is a risk that has been excluded from I&M's support put forth in this proceeding. Accordingly, in the event that lease termination costs arise as a result of the failure of the Rockport SCR Project being successful at allowing I&M the use of Unit 2 though the end of the current lease, the burden of proving such costs are reasonable and necessary and therefore recoverable from customers remains on I&M.

Nevertheless, we find, based on the evidence presented, that there is a reasonable likelihood of success for the proposed project.

7. <u>The cost and feasibility of the retirement of an existing generating facility</u>. As discussed by Mr. Weaver, I&M has set forth the relative cost and feasibility of a Rockport Unit 2 retirement (or, in this circumstance, return to lessors) option and demonstrated that the cost of that alternative would likely significantly exceed that of the proposed Rockport SCR Project. Mr. Rutter's analysis confirmed the rate impact to customers of the retrofit option is lower than the alternative of terminating the lease.

Mr. Fisher asks the Commission to deny the requested CPCN and to require I&M to expediently file a plan for the replacement of the capacity and energy requirements otherwise met through Rockport Unit 2. He argues that the certainty of terminating the lease in 2019 at a known cost appears far more attractive. However, we disagree because the option to return the unit to the lessor in 2019 and prior to the end of the original lease term is not a reasonable or cost effective compliance option. We find that the record reflects that I&M reasonably considered retrofit and retirement (i.e., return the unit to lessor) options.

8. <u>The dispatching priority for the facility utilizing the CCT</u>. In accordance with Ind. Code § 8-1-8.7-3(b)(8) and as discussed by Mr. Weaver, I&M has implicitly set forth that the dispatch priority of this proposed NO_X-controlled Rockport Unit 2 will not be adversely impacted based on I&M's economic analysis. Mr. Weaver stated it would be anticipated that the unit's annual capacity factor will not be significantly different from what it would have been had this SCR retrofit not been installed. The other party witnesses did not

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[3] JI Ex 1, Attachment JIF-18, at Schedule 3, shows that the termination value relates to a specific date. The December 2019 and June 2020 dates indicate that the tolling of the SCR installation deadline did not materially alter the termination value.

specifically address this issue. We find the record shows that the Rockport SCR Project is not expected to significantly change the dispatching order of the units.

9. <u>Any other factors the Commission considers relevant, including whether the construction, implementation, and use of clean coal technology is in the public's interest</u>. Other factors supporting approval of the Rockport SCR Project are discussed above and below.

(b) <u>Ind. Code 8-1-8.7-4(b)</u>. We now address the four required findings in Ind. Code § 8-1-8.7-4(b).

1. <u>Public convenience and necessity will be served by the construction, implementation, and use of CCT</u>. The public convenience and necessity criterion is common in public utility matters and generally concerns whether the proposal is fitted or suited to the public need. Thus, the Commission must be satisfied that there is a reasonable and apparent need for the Rockport SCR Project. The record shows that the Rockport SCR Project will reduce NO_x emissions and this benefits the environment and furthers the public interest. The Rockport SCR Project is also required by the consent decree and consistent with anticipated environmental regulations. Moreover, as Mr. Hendricks explained in his rebuttal testimony, installing the SCR on Rockport Unit 2 will provide important compliance flexibility to I&M in the event there is an increase in market prices for allowances, a decrease in state ozone season NO_x budgets, or an increase in plant ozone season NO_x emissions. Importantly, as discussed by Mr. Weaver, the loss of the Rockport Unit 2 from I&M's generation portfolio would expose I&M ratepayers to significant uncertainty concerning PJM market price fluctuations and generation availability for up to 1,100 MW, which the Commission considers to be risky and less than ideal. Based on our review of the evidence and consideration of the other statutory factors, we find the public convenience and necessity will be served by the construction, implementation, and use of the Rockport SCR Project.

2. <u>Approval of Cost Estimate</u>. Mr. Pifer provided the cost estimate, explained how it was developed, and discussed I&M's cost management process. The Industrial Group recommended the Commission place a cap on the Rockport SCR Project costs recoverable in the rider at I&M's current estimate. We disagree with the Industrial Group's recommendation because the statutory framework allows for ongoing review of a project's status and costs in the ongoing rider proceedings. This process includes consideration of changes in the cost estimate.[4] Based upon the record evidence, we find that the estimated cost of the Rockport SCR Project of $274.2 million (excluding AFUDC) is approved. While this amount does not include AFUDC, the actual accrued amount of AFUDC will be included as part of the approved cost.

3. <u>Use/Non-Use of Indiana Coal</u>. Rockport Unit 2 does not burn Indiana coal and the evidence shows the Rockport SCR Project is economically

[4] The Commission-approved cost estimate is based on the evidence presented in this Cause. I&M must prove that any incremental project completion costs, for example those resulting from changes in the project timing, are reasonable and recoverable from ratepayers.

justified. The provisions of the state environmental statutes providing favorable regulatory treatment to projects using Indiana or Illinois Basin coal have been held to be an unconstitutional interference with interstate commerce, but severable from the rest of the statutes which remain valid. *General Motors Corp. v. Indianapolis Power & Light Co.*, 654 N.E.2d 752, 763-64 (Ind. Ct. App. 1995); *Alliance For Clean Coal v. Bayh*, 72 F.3d 556 (7th Cir. 1995); see also *S. Ind. Gas and Electric Co.*, Cause No. 41864, at 7 (IURC 8/29/2001); *N. Ind. Pub. Serv. Co.*, Cause No. 42150, at 5 n.3 (IURC 11/26/2002); *Indianapolis Power & Light Co.*, Cause No. 42170, at 5 n.1 (IURC 11/14/2002); *Indianapolis Power & Light Co.*, Cause No. 44242, at 30 n. 2 (IURC 8/14/2013). We will accordingly not rely on such statutory provisions as a prerequisite for approval.

4. <u>Ind. Code § 8-1-8.7-3(b)</u>. Our findings on each of the factors described in Ind. Code § 8-1-8.7-3(b) are set forth above.

5. <u>Conclusion</u>. Based on our review of the evidence and consideration of the other statutory factors, we find the public interest will be served by the construction, implementation, and use of the Rockport SCR Project.

(ii) <u>Ongoing Review</u>. I&M requested ongoing review of the construction of the Rockport SCR Project to be conducted annually as part of I&M's CCTR proceedings. Mr. Williamson explained that I&M will include progress reports of construction, updated cost estimates and any revisions to cost estimates for the Rockport SCR Project in the CCTR filing. This approach allows for timely review of the construction and of any changes in the estimated Rockport SCR Project cost. Mr. Fisher recommended the Commission require I&M to conduct an updated analysis and provide parties an opportunity to review and respond to that analysis; he further recommended that the Commission "maintain the ability to adjust the rider at any time prior to 2019" following the finding of this updated analysis. We find Mr. Fisher's proposal goes beyond what is contemplated by the pre-approval and ongoing review process. Accordingly, we find I&M's proposal for ongoing review of the Rockport SCR Project reasonable and should be approved.

B. <u>Chapter 8.8 and Ind. Code § 8-1-2-6.7</u>.

(i) <u>Clean Energy Project</u>. Ind. Code § 8-1-8.8-2(1)(B) defines "Clean Energy Projects" as projects "to provide advanced technologies that reduce regulated air emissions from existing energy generating plants that are fueled primarily by coal . . . ." This statute expressly provides that the term "Clean Energy Project" includes SCR equipment. As discussed above, Mr. Pifer explained that the SCR technology will reduce regulated air emissions from Rockport Unit 2 and will allow I&M to continue to utilize this coal-fired generating asset. Accordingly, we find that the Rockport SCR Project is a Clean Energy Project.

(ii) <u>Timely Cost Recovery and Depreciation</u>. Ind. Code § 8-1-8.8-11 provides that the Commission shall encourage Clean Energy Projects by creating financial incentives designated in the statute if the project is found to be reasonable and necessary. Our discussion above concludes that a CPCN under Ind. Code ch. 8-1-8.7 should be issued and thus demonstrates that the Rockport SCR Project is reasonable and necessary consistent with the findings herein. Ind. Code § 8-1-8.8-11 identifies the timely recovery of costs and expenses incurred during construction and operation of a Clean Energy Project as one type of financial incentive that shall be used to encourage a Clean Energy Project.

I&M requested timely recovery of I&M's ownership share via annual CCTR filings as a Clean Energy Project and QPCP. Such request is consistent with that approved by the Commission for I&M's Rockport Unit 1 SCR in Cause No. 44523. The Industrial Group proposed that any cost recovery be conditioned on the SCR remaining used and useful to I&M customers after December 7, 2022. The record shows the SCR retrofit is the reasonable least-cost compliance option, even if it is only in service for the benefit of I&M customers through the end of the original lease term, when compared to the uncertain cost of acquiring approximately 1,100 MW of capacity and energy resources from others or the PJM market. Accordingly, we decline to accept the conditioning of the allowed cost recovery as proposed by the Industrial Group.

Our discussion and findings above support the conclusion that the Rockport SCR Project constitutes CCT and QPCP as those terms are defined in Ind. Code §§ 8-1-2-6.7 and 6.8. I&M's proposal to depreciate its ownership share of the Rockport SCR Project over ten years is consistent with Ind. Code § 8-1-2-6.7. We decline to adopt the Industrial Group's recommendation that the depreciation period for the Rockport SCR Project be extended to 20 years. We find that depreciating the Rockport SCR Project over ten years strikes a reasonable balance between the ratemaking recognition of the Rockport SCR Project and the period over which it may be reasonably known to operate. A ten-year depreciation period is consistent with that approved in Cause No. 44523 for the Unit 1 SCR.

We find that I&M's proposed accounting and ratemaking treatment for the Rockport Unit 2 SCR is in conformity with applicable rules and statutes. Further, the allocation of costs in the CCTR is supported by the testimony of Mr. Phillips and Mr. Williamson. Substantial record evidence demonstrates, and we find, that I&M's proposed accounting and ratemaking treatment, including a ten-year depreciation period and the allocation of fixed costs using a 6 CP method, is reasonable and should be approved.

C. Conclusion. Having considered the evidence in this Cause, we find that the Rockport SCR Project is reasonable and necessary as set forth above. Substantial evidence shows that the installation of SCR technology at Unit 2 is a reasonable least-cost alternative to meeting I&M's capacity and energy obligations. Accordingly, the Commission finds that a CPCN shall be granted to I&M for the Rockport SCR Project. As discussed above, I&M's proposed accounting and ratemaking treatment is reasonable and is approved.

13. 2018 IRP and Lease Renewal Decision. The future lease decisions regarding the continued reasonableness of Rockport Unit 2 in the resource portfolio I&M employs to meet its Indiana retail customer's needs was a point of discussion throughout this proceeding. While the Commission has concluded that the Rockport SCR Project is reasonable in extending the life of Unit 2 through the current lease term, the lease decisions are not yet ready for consideration. Notwithstanding, we agree that the decision is one all parties have a vested interest in fully exploring in an appropriate regulatory setting. Mr. Rutter testified that I&M should review the balance of its options and model for future generation alternatives. Mr. Phillips testified that I&M

needs to set out a plan for generation. I&M's 2018 IRP would appear to present a reasonable opportunity for all stakeholders to consider and discuss informally I&M's future generation plans. Further, during the hearing Mr. Chodak was asked if I&M would bring the extension of the lease before the Commission. Mr. Chodak testified as follows:

> If we were – so if we did a renewal of the Lease under existing terms or if we did it as a fair market renewal of the Lease, under those two options, which is the only two really you can do under the Lease, yes, we would bring those to the Commission.

Tr. of Mar. 1, 2017 hearing at A-89. We agree with Mr. Chodak that any lease renewal decision should be brought before the Commission. Accordingly, while informal consideration of I&M's future generation plans are encouraged, any extension of the Rockport Unit 2 lease entered into by I&M for the purposes of serving its Indiana retail customers shall be subject to future consideration before the Commission in a formally docketed proceeding.

14. **Confidentiality Findings.** I&M filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information on October 21, 2016, which Motion was supported by affidavit showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. The Presiding Officers issued a Docket Entry on December 5, 2016 finding such information to be preliminarily confidential, after which such information was submitted under seal. There was no disagreement among the parties as to the confidential and proprietary nature of the information submitted under seal in this proceeding. We find all such information is confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. I&M is hereby granted a Certificate of Public Convenience and Necessity for the construction, installation and use of the Rockport SCR Project pursuant to Ind. Code ch. 8-1-8.7. This Order constitutes the Certificate.

2. I&M's cost estimate for the Rockport SCR Project of $274.2 million (excluding AFUDC) is reasonable and approved. While this amount does not include AFUDC, the actual accrued AFUDC will be included as part of the approved cost.

3. The Rockport SCR Project is determined to constitute a "Clean Energy Project" under Ind. Code ch. 8-1-8.8. and the timely recovery of costs and expenses through I&M's annual CCTR as proposed by I&M is approved.

4. I&M's request for ongoing review pursuant to Ind. Code § 8-1-8.7-7 is approved. I&M shall file the ongoing review reports as set forth in Para. 12(A)(ii) for the purpose of ongoing review.

5. I&M is authorized to add to the value of I&M's property for ratemaking purposes the value of the Rockport SCR Project as proposed by I&M. I&M shall add the approved return to its net operating income authorized by the Commission for purposes of Ind. Code § 8-1-2-42(d)(3) in all subsequent FAC proceedings.

6. I&M is authorized to depreciate I&M's ownership share of the Rockport SCR Project over a period of ten years.

7. I&M is granted accounting authority to implement its proposed ratemaking in accordance with this Order.

8. The material submitted to the Commission under seal is declared to contain trade secret information as defined in Ind. Code § 24-2-3-2 and therefore is exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code § 8-1-2-29.

9. This Order shall be effective on and after the date of its approval.

<u>HUSTON, FREEMAN, WEBER, AND ZIEGNER CONCUR</u>:

APPROVED: MAR 2 6 2018

I hereby certify that the above is a true and correct copy of the Order as approved.

Mary M Becerra

Mary M. Becerra
Secretary of the Commission

DATA REQUEST

KPSC 1_6 Refer to the Osborne Testimony, pages 8-9. Explain whether Kentucky Power will continue to incur any costs related to the Rockport Unit 2 SCR project after December 7, 2022, in the event that the Unit Power Agreement with the Rockport Plant (UPA) is not extended past December 7, 2022. Provide the current status of the UPA renewal.

RESPONSE

Because the Company does not intend to extend the UPA beyond December 7, 2022, Kentucky Power will cease to incur costs related to the Rockport Unit 2 SCR project after December 7, 2022.

As reflected in Kentucky Power's December 20, 2019 Integrated Resource Plan filing, the Company currently expects that the Rockport UPA will expire and not be renewed. Should the Company's position regarding the UPA change, the Company will seek appropriate approval from the Commission for an extension of the UPA or the acquisition of replacement energy and capacity.

Witness: Lerah M. Scott

DATA REQUEST

KPSC 1_7 Refer to the Direct Testimony of Lerah M. Scott (Scott Testimony), page 5. Identify the other partial owners of the Rockport Plant and explain whether these entities must also receive regulatory approval of the Rockport Unit 2 SCR project.

RESPONSE

Rockport Unit 1 is owned by Kentucky Power affiliates Indiana Michigan Power Co. ("I&M") and AEP Generating Company ("AEG"). Rockport Unit 2 is owned by Wilmington Trust Co., not in its individual capacity, but solely as owner trustee under twelve separate trusts. Wilmington Trust Co. leases an undivided 50% share of Unit 2 to I&M, and an undivided 50% share to AEG. AEG in turn leases an undivided 30% of its interest in Unit 2 to Kentucky Power under the UPA, thereby yielding Kentucky Power's 15% interest in Unit 2 (30% of 50%). AEG leases the remaining 70% of its interest in Unit 2 to I&M, thereby yielding I&M's 85% interest in Unit 2 (50% + 70% of 50%).

Wilmington Trust Co. was not required to seek regulatory approval of the Rockport Unit 2 SCR project. I&M was required to seek and was granted a Certificate of Public Convenience and Necessity (CPCN) from the IURC in Cause No. 44871.

Witness: Lerah M. Scott

Kentucky Power Company
KPSC Case No. 2019-00389
Commission Staff's First set of Data Request
Dated January 17, 2020

DATA REQUEST

KPSC 1_8 Refer to the Scott Testimony, page 5, the Indiana Utility Regulatory Commission's March 26, 2018 final Order in Cause No. 44871 and the Federal Energy Regulatory Commission (FERC) Docket No. ER19-717-000.2 For "Option 1 B," explain whether l&M's economic analysis accounted for the revised depreciation rates sought by AEP Generating Company in FERC Docket No. ER19-717-000.

RESPONSE

No. I&M's economic analysis in Cause No. 44871 was performed prior to AEP Generating Company seeking revised depreciation rates in FERC Docket No. ER19-717-000 and therefore did not account for the revised depreciation rates that FERC accepted for filing after providing for notice and comment in that docket.

Witness: Lerah M. Scott

DATA REQUEST

KPSC 1_9 Refer to the Scott Testimony, page 6. Explain whether the Rockport Unit 2 SCR project will have any impact on the dispatching of Rockport Unit 2.

RESPONSE

The only effect the Unit 2 SCR project will have on the dispatch of Unit 2 is a small increase in environmental consumables included in the unit's offer curve. As a result, the project is expected to have a negligible impact on the dispatch of the unit, by increasing its offer curve by approximately $0.10/MWh.

Witness: Debra L. Osborne

DATA REQUEST

KPSC 1_10 Refer to the Scott Testimony, page 6. Explain how often catalyst layers must be replaced and provide the estimated cost.

RESPONSE

It is estimated that each of the catalyst layers will require replacement after three years of generating unit run time, at an estimated cost of $4.4 million per layer (in 2023 dollars).

Witness: Debra L. Osborne

Kentucky Power Company
KPSC Case No. 2019-00389
Commission Staff's First set of Data Request
Dated January 17, 2020

DATA REQUEST

KPSC 1_11 Refer to the Scott Testimony, pages 8-9. Explain how the revised depreciation rates of 2.95 percent for Rockport Unit 1 and 28.48 percent for Rockport Unit 2 will result in the units being fully depreciated.

RESPONSE

AEG provided a depreciation study in FERC Docket No. ER19-717-000. The depreciation rates determined by the study were intended to provide recovery of invested capital, cost of removal, and credit for salvage over the expected life of the property. The depreciation study can be found at https://etariff.ferc.gov/TariffSectionDetails.aspx?tid=3301&sid=248017 pages 33-34 and is also attached as KPCO_R_KPSC_1_11_Attachment1.

Witness: Lerah M. Scott

AEP GENERATING COMPANY (AEGCO) - ROCKPORT PLANT
SCHEDULE I - DEPRECIATION RATE CALCULATION - UNIT 1
USING BEGINNING BALANCES AT DECEMBER 31, 2017

Current Depreciation Rate through December 2018 = **3.52%**

Depreciation Rate from January 2019 through December 2028 = **2.95%**

YEAR	Additions	Retirements	Ending Unit Balance	Average Unit Balance	Depreciation Accrual (1)	Terminal Demolition Amount	Ending Reserve Balance	Original Cost less Reserve
2017			893,534,848				606,844,929	286,689,919
2018	0	0	893,534,848	893,534,848	31,452,427	0	638,297,356	255,237,492
2019	0	0	893,534,848	893,534,848	26,353,885	0	664,651,241	228,883,607
2020 (2)	4,180,000	0	897,714,848	895,624,848	26,415,527	0	691,066,768	206,648,080
2021	0	0	897,714,848	897,714,848	26,477,169	0	717,543,937	180,170,911
2022	0	0	897,714,848	897,714,848	26,477,169	0	744,021,106	153,693,742
2023	0	0	897,714,848	897,714,848	26,477,169	0	770,498,275	127,216,573
2024	0	0	897,714,848	897,714,848	26,477,169	0	796,975,444	100,739,404
2025	0	0	897,714,848	897,714,848	26,477,169	0	823,452,613	74,262,235
2026	0	0	897,714,848	897,714,848	26,477,169	0	849,929,782	47,785,066
2027	0	0	897,714,848	897,714,848	26,477,169	0	876,406,951	21,307,897
2028 (3)	0	0	897,714,848	897,714,848	26,477,169	5,169,287	897,714,833	15
TOTALS	4,180,000	0			296,039,191			

Rockport Unit 1 Net Plant at December 2017	286,689,919
Additions to Plant 2019-2028	4,180,000
Unit 1's Share of Terminal Demolition Cost Estimate	5,169,287
Total Amount Remaining to Depreciate	296,039,206

(1) Assuming current depreciation rates continue through December 2018 and change on January 2019 . The calculation includes an estimated addition for a CCR (2020) project .

(2) 2020 - a forecast addition to original cost of Rockport Plant totaling $4,180,000 for the ash pond relining (CCR).

(3) 2028 - AEG's share of Rockport Unit 1's terminal demolition cost ($10,338,573/2 = $5,169,287) that will be charged to accumulated depreciation.

AEP GENERATING COMPANY (AEGCO) - ROCKPORT PLANT
SCHEDULE I - DEPRECIATION RATE CALCULATION - UNIT 2
USING BEGINNING BALANCES AT DECEMBER 31, 2017

Current Depreciation Rate through December 2018 = **3.52%**

Depreciation Rate from January 2019 through December 2022 = **28.48%**

YEAR	Additions	Retirements	Ending Plant Balance	Average Plant Balance	Depreciation Accrual (1)	Terminal Demolition Amount	Ending Reserve Balance	Original Cost less Reserve
2017			82,884,421				29,705,841	53,178,580
2018	0	0	82,884,421	82,884,421	2,917,532	0	32,623,373	50,261,048
2019	0	0	82,884,421	82,884,421	23,604,967	0	56,228,340	26,656,081
2020 (2)	135,373,000	0	218,257,421	150,570,921	42,881,660	0	99,110,000	119,147,421
2021	0	0	218,257,421	218,257,421	62,158,354	0	161,268,354	56,989,067
2022 (3)	0	0	218,257,421	218,257,421	62,158,354	5,169,286	218,257,422	(1)
TOTALS	135,373,000	0			193,720,867			

Rockport Unit 2 Net Plant at December 2017	53,178,580
Additions to Plant 2019-2022	135,373,000
Unit 2's Share of Terminal Demolition Cost Estimate	5,169,286
Total Amount Remaining to Depreciate	193,720,866

(1) Assuming current depreciation rates continue through December 2018 and change on January 2019 . The calculation includes a forecasted addition of $135,373,000 for the U2 SCR (2020) project.

(2) 2020 - Forecast additions to original cost of Rockport Unit 2 totaling $135,373,000 for the Unit 2 SCR.

(3) 2022 - Unit 2's share of the terminal demolition cost ($10,338,573/2 = $5,169,286) to be charged to accumulated depreciation.

Kentucky Power Company
KPSC Case No. 2019-00389
Commission Staff's First set of Data Request
Dated January 17, 2020

DATA REQUEST

KPSC 1_12 Refer to the Direct Testimony of Gary 0. Spitznogle (Spitznogle Testimony), Exhibit GOS-3, page 12 of 38, regarding the implementation of an enhanced dry sorbent injection. Provide the status of the enhanced dry sorbent injection technology that is required to be operational by June 1, 2020, for Rockport Unit 2 and December 31, 2020, for Rockport Unit 1.

RESPONSE

The projects to implement enhanced dry sorbent injection technology for Rockport Unit 1 and Rockport Unit 2 are on schedule.

Witness: Debra L. Osborne

VERIFICATION

The undersigned, Mark A. Becker, being duly sworn, deposes and says he is the Resource Planning Manager, American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Mark A. Becker

MARK A. BECKER

STATE OF Oklahoma)
)
COUNTY OF Tulsa)

Case No. 2019-00389

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Mark A. Becker this the 30TH day of January, 2020.

LISA R. GOODMAN NOTARY # 08003216 EXP. 03/18/20 PUBLIC STATE OF OKLAHOMA

Lisa R. Goodman

Notary Public

My Commission Expires:

(SEAL)

VERIFICATION

The undersigned, Debra L. Osborne, being duly sworn, deposes and says she is the Vice President of Generating Assets for Appalachian Power Company and Kentucky Power Company, that she has personal knowledge of the matters set forth in the foregoing responses and the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Debra L. Osborne

DEBRA L. OSBORNE

STATE OF West Virginia)
)
COUNTY OF Kanawha)

Case No. 2019-00389

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Debra L. Osborne this the 29 day of January, 2020.

Maisha T. Staples

Notary Public

My Commission Expires:
November 23, 2021

(SEAL)

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
Maisha T. Staples
Appalachian Power
500 Lee St. E. Laidley Tower, Suite 800
Charleston, WV 25301
My Commission Expires November 23, 2021

VERIFICATION

The undersigned, Lerah M. Scott, being duly sworn, deposes and says she is Regulatory Consultant Associate for Kentucky Power Company, that she has personal knowledge of the matters set forth in the foregoing responses and the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Lerah Scott

LERAH M. SCOTT

COMMONWEALTH OF KENTUCKY)
) Case No. 2019-00389
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Lerah M. Scott this the 30th day of January, 2020.

Trisha Nance

Notary Public

My Commission Expires:
9-26-2023

(SEAL)

OFFICIAL SEAL
TRISHA NANCE
NOTARY PUBLIC - KENTUCKY
STATE-AT-LARGE
My Comm. Expires September 26, 2023
ID # 632421

VERIFICATION

The undersigned, Gary O. Spitznogle, being duly sworn, deposes and says he is the Vice President - Environmental Services, American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

GARY O. SPITZNOGLE

STATE OF OHIO	)	
	)	**Case No. 2019-00389**
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Gary O. Spitznogle this the 29th day of January, 2020.

Notary Public

My Commission Expires:

Never

(SEAL)

NOTARIAL SEAL
STATE OF OHIO

Paul D. Flory
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.