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By electronic mail
Indiana Utility Regulatory Commission
ATTN: Research, Policy, and Planning Division
101 W. Washington Street, Suite 1500 E
Indianapolis, IN 46204-3407
bborum@urc.in.gov

RE: Indiana Coal Council Comments on I&M IRP

Dear Dr. Borum,

On behalf of the Indiana Coal Council (ICC), please accept the attached comments on Indiana Michigan Power Company's (I&M) 2018-19 Integrated Resource Plan (IRP). The ICC greatly appreciates the opportunity afforded by the Commission to submit stakeholder comments as part of the IRP process. The ICC also greatly appreciates the cooperation it has received from I&M throughout the stakeholder process.

Please direct any questions or requests for further information related to the ICC's comments to me at the information above. Should the Commission wish to speak with the ICC's consultants, we would be happy to make them available to you.

All the best,

Jeffery A. Earl

ICC COMMENTS ON I&M IRP

The Indiana Coal Council (ICC) conducted a review of the Integrated Resource Plan (IRP) that Indiana Michigan Power Company (I&M) prepared and submitted to the Indiana Utility Regulatory Commission (IURC) on July 1, 2019.

BACKGROUND

I&M submitted its IRP on July 1, 2019. Prior to its submission, I&M had asked for and received three extensions related to the filing of the IRP. The first extension delayed the filing deadline from November 1, 2018, to February 1, 2019, to allow additional time for the United States District Court for the Southern District of Ohio ("Court") to rule on the proposed Fifth because I&M believed the provisions in the Fifth Modification applicable to the Rockport Plant would affect its resource plans. The second request which extended the filing deadline to May 1, 2019, was to provide additional time for stakeholder involvement. The third extension to July 1, 2019, was to update modeling results.

I&M analyzed a number of scenarios and identified a Preferred Plan. Under the Preferred Plan, the lease for Rockport Unit 2 would not be extended beyond 2022, Rockport Unit 1 would be retired by the end of 2028, and the Cook nuclear units 1 and 2 would operate through their current license periods, which are 2034 and 2038, respectively. These resources would be replaced by a combination of solar, energy storage, energy efficiency, and short-term market purchases through 2028 and thereafter by natural gas, solar, and battery storage, as detailed in the chart below.

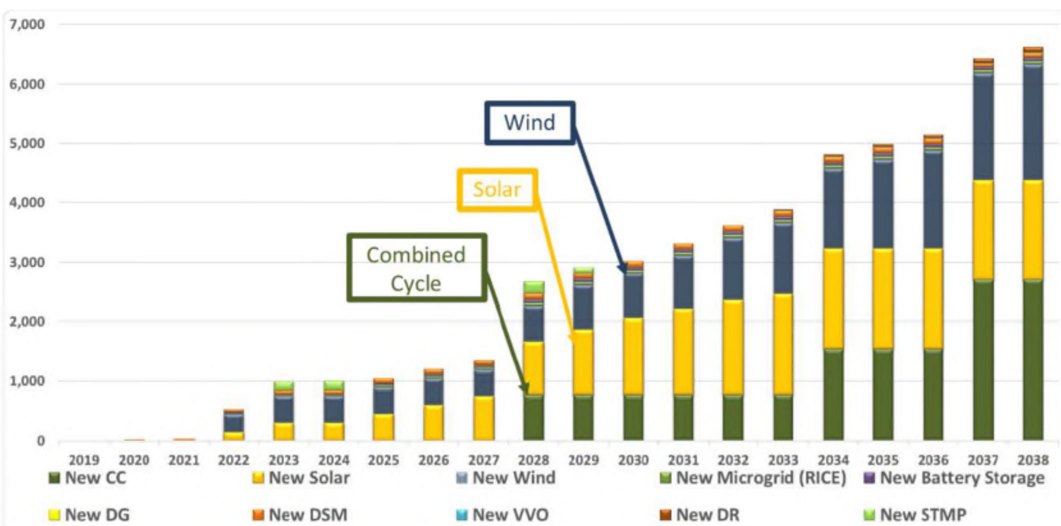

Figure ES- 2. I&M New Capacity Additions – Nameplate (MW)

The resulting resource mix is as follows:

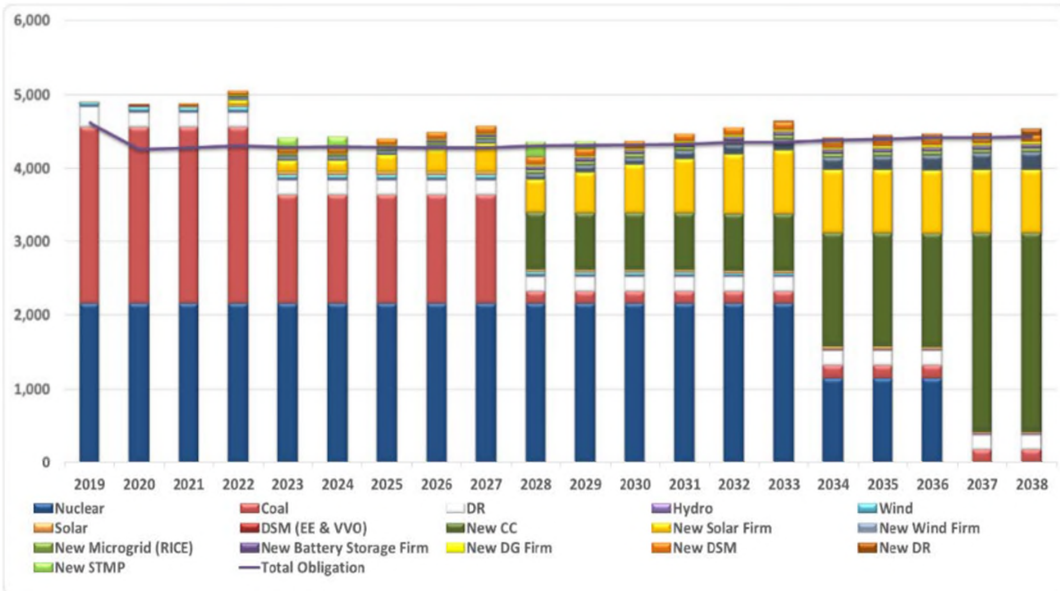

Figure 4. Existing and New Capacity Additions – FIRM (MW)

With this resource mix, more than 40 percent of I&M's expected generation in 2040 would be from natural gas.

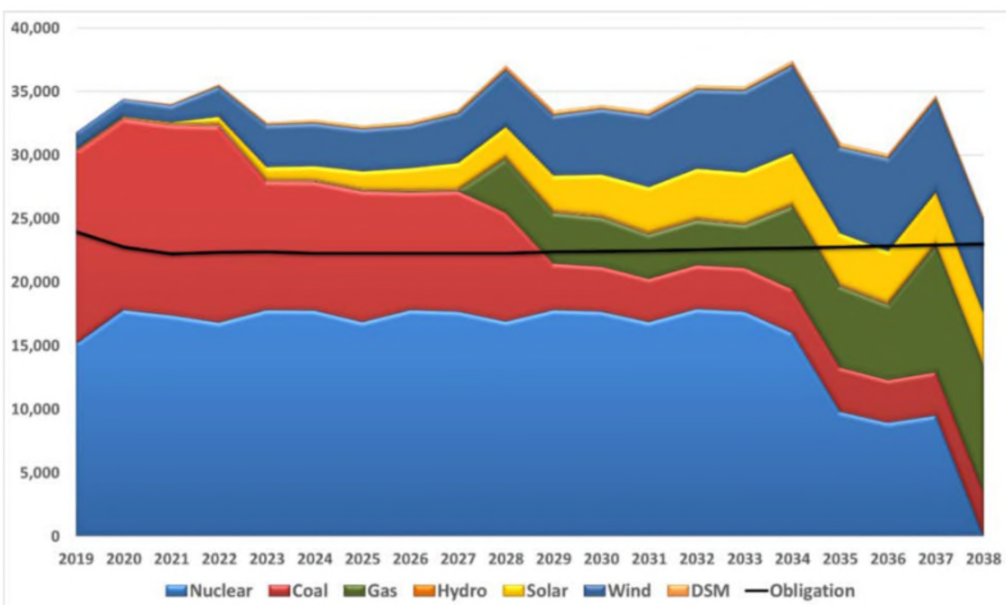

Figure ES- 5. I&M's Preferred Plan Annual Energy Position (GWh)

THE CONSENT DECREE

The Consent Decree is a 2007 Settlement between American Electric Power (AEP), the Department of Justice (DOJ), and a number of states that filed lawsuits against AEP for alleged violations of the Clean Air Act. The Consent Decree involves 16 plants across multiple jurisdictions. The Consent Decree has been formally modified four times as follows:

- American Electric Power Service Corp. First Modification to the Consent Decree (April 5, 2010);
- American Electric Power Service Corp. Second Modification to the Consent Decree (December 28, 2010);
- American Electric Power Service Corp. Third Modification to the Consent Decree (2013);
- American Electric Power Service Corp. Fifth Modification to the Consent Decree (July 17, 2019);

The Fifth Modification seems to have been required as a result of I&M's failure to meet the requirements of the Third Modification to the Consent Decree related to the retrofit of selective catalytic reduction systems (SCR) on Rockport Unit 2 due to ongoing litigation with the owners of Rockport Unit 2. According to I&M, it would have been subject to a plus $700 million dollar payment to the lessors for early lease termination.[1] Alternatively, I&M would have been subject to onerous penalties for a failure to comply with the provisions of the Consent Decree.[2] It is not certain that the IURC would have allowed recovery of either the payment for early termination or the penalties from ratepayers; therefore, it was to I&M's advantage to modify the Consent Decree because the IURC has traditionally approved the costs of projects required for compliance with a consent decree.

The Fifth Modification required I&M to do the following: retrofit the Rockport units with enhanced DSI systems; retire Rockport 1 by the end of 2028; achieve a 10,000 ton-per-year cap on emissions at the Rockport Plant beginning in calendar year 2021; and achieve a 30-day rolling average SO_2 emissions rate of 0.15 lbs/MMBtu and a 30-day rolling average NO_x emission rate of 0.090 lbs/MMBtu at the combined stack beginning in calendar year 2021. In exchange, I&M was given a five-month delay in completing the required SCR installation at Rockport Unit 2 until June 1, 2020. The IRP states "[t]he unit characteristics included in the Fifth Joint Modification are not included in the modeling results of this IRP." (p. 45).

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[1] Cause No. 44871, Mar. 25, 2018 Order, p. 4.

[2] The penalties to which AEP would have been subject are contained in Paragraph 150 of the 2007 Consent Decree and are provided below in Exhibit I.

There are three issues with the IRP related to the Fifth Modification. First, as noted above, the requirements of the Fifth Modification, which was approved July 19, 2019, were not included in the IRP, even as a scenario. Second, I&M has not calculated the incremental costs associated with the Fifth Modification, and it is not clear whether the incremental costs associated with compliance with the Fifth Modification compared to the Third Modification should be borne solely by AEP/I&M or are allowed to be passed through to ratepayers. Third, the mandatory retirement of Rockport Unit 1 by the end of 2028 as a result of the Fifth Modification represents the loss of an important and valuable option to I&M particularly given I&M's plans not to extend the Rockport Unit 2 lease and its plan to replace the capacity with natural gas.

I&M has not justified the need for the Fifth Modification. I&M explains in a filing in Cause 44871, the need for the Fifth Modification stems from (1) I&M's failure to retrofit SCR's on Rockport Unit 2 according to the agreed-upon schedule in the Third Modification due to ongoing litigation with the owners of Rockport Unit 2 and (2) an adverse decision from the Sixth Circuit regarding AEP's obligations under its sale-leaseback agreement, which AEP apparently believed would not happen.[3] AEP notes that "all of the other obligations of the Third Joint Modification have been satisfied."[4] According to the filing, "[AEP] has tirelessly investigated alternative approaches that would allow AEP to remove from the Consent Decree the obligations at Rockport Unit 2 that the Sixth Circuit … has found may have exceeded AEP's authority under the Lease, while revising AEP's obligations in other respects to preserve—and actually exceed—the environmental benefits the Consent Decree was designed to achieve."[5] In other words, it appears that AEP gambled that it would receive a favorable court ruling related to Rockport Unit 2 and lost. AEP/I&M now appears to be of the opinion that the cost of complying with the requirements of a Consent Decree are recoverable because of the legal obligation. ICC believes that this is not the case if the obligations are a result of the Company's failure to perform. The IURC has found in other cases with similar facts that ratepayers are not automatically responsible for the costs associated with compliance with a consent decree.[6]

IRP ANALYSIS

I&M evaluated a select number of possible generation portfolios across a range of possible future power market conditions. In addition to failing to analyze the Fifth Modification, ICC identified a number of significant flaws to I&M's analysis. The most significant are discussed below.

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[3] *Indiana Michigan Power Company's Submission of Additional Information Concerning Rockport Unit 2 Lease*, Cause No. 44871 (filed Jan. 9, 2018).

[4] *Id*. p. 8 of *Defendants' Supplemental Motion and Memorandum in Support of Fifth Modification of Consent Decree*.

[5] *Id*. p. 2.

[6] *See*, *e.g.*, Cause Nos. 43956, 43992, 42992 ECR 1, 44012, 44016, 44331, and 44871.

Rockport Unit 2 Lease Extension

In its preferred plan, under which the lease for Rockport Unit 2 is not extended, I&M had to make an assumption for the cost of the Rockport 2 lease. While I&M treats the actual assumed cost as confidential, it can be estimated using the public data in Exhibit C to the IRP. In Case 9 (the Preferred Plan), the lease costs decline from $214 million in 2022 to $96 million in 2023—the approximate $120 million decline can be viewed as the existing lease cost for Rockport Unit 2. In Case 8, which assumes an extension of the Rockport Unit 2 lease, the lease cost in 2023 is $240 million, which is a $144 million increase from the cost assumed in the no lease extension case. Therefore, it can be surmised that I&M assumed the cost of the new lease would increase by about $20 - $25 million above the old lease terms.

This assumption is unreasonable and is not supported by any market data. Because of I&M's unrealistic lease extension cost assumption, the case with an extension of the Rockport lease is uneconomic. The extension of the lease at a market-based level or the repurchase of the plant would likely be economic, as the plant produces savings against the preferred alternative according to I&M's projections absent the lease expense.[7] As a result, there is very likely a lease price that would make it economic for both the lesser and I&M to continue operating the plant.

I&M's approach to the lease payment is not surprising. In the first shareholder meeting on the IRP, I&M indicated it did not plan to even consider a lease extension at Rockport Unit 2. The notes from the stakeholder meeting note the following:

> A stakeholder asked if Rockport unit 2 would be modeled in this IRP. John stated that I&M's IRP will not consider Rockport unit 2 as a viable resource option after 2021/22, and it will not be included as a resource in the IRP modeling. John stated that we are not making a resource decision; we are making an IRP modeling assumption. I&M does not know what the cost of a lease renewal would be and is not going to model it. Matt McKenzie, I&M's internal counsel, indicated that the most likely outcome is that the lease would not be renewed. And for now, all we are talking about is an IRP modeling assumption, nothing more [8]

Subsequently, I&M elected to consider it. However, the manner in which it was considered shows no real intent to extend the lease.

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[7] Comparing the Rockport 2 lease extension (Case 8) to I&M's preferred plan shows over a $110 million NPV benefit for the period 2023-2027 when lease costs are excluded.

[8] Workshop 1 Meeting Minutes, Mar. 1, 2018, page 9 available at: https://www.indianamichiganpower.com/global/utilities/lib/docs/info/projects/IMIntegratedResourcePlan/Workshop1MeetingMinutesMarch_1_2018.pdf.

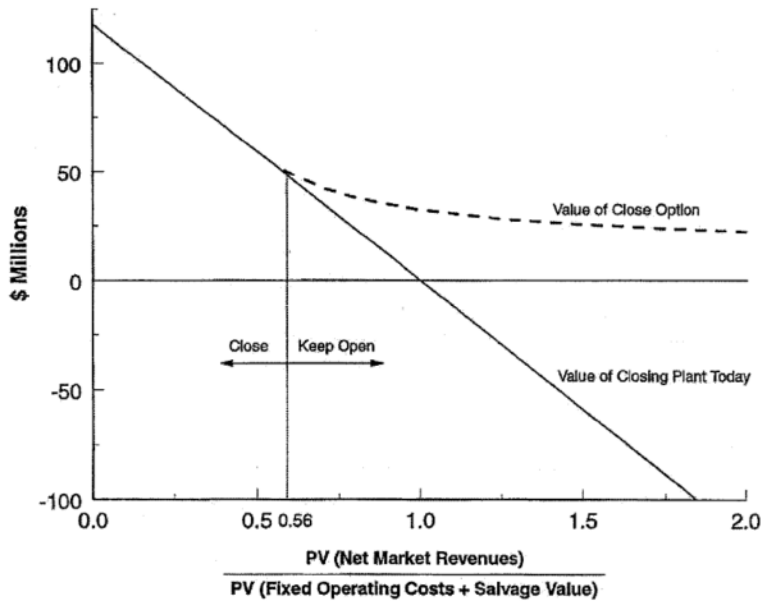
In order to comply with the Fifth Modification, I&M has committed to the installation in 2020 of additional environmental controls at Rockport – a new SCR for NO_x control on Unit 2 and enhanced SO_2 controls on both units. By extending the life of Rockport Unit 2, the costs associated with these new controls would be spread over a longer period. I&M should be required to explore the lease extension option and should base its assumptions regarding that option on market-based data.

Option or Delay Analysis

Another major flaw in the IRP is I&M's failure to evaluate the lost option of a Rockport unit continuing beyond 2028. I&M took a deterministic approach to setting and evaluating portfolios and does not allow portfolios to change as conditions change. For example, if the High case conditions actually occur in the future, adjustments can be made in the portfolio, i.e., retirement or changing what resource gets added. I&M's approach does not recognize the dynamism of resource planning and only looks at static portfolios.

The ability to delay new investment and to make early retirements of an existing resource provides value and can be evaluated using option valuation techniques.[9] Using these techniques shows that in the face of volatile commodity prices and an uncertain future, it can actually be value creating to continue to operate existing resources even if the expected value of operation is below zero, because there is value to holding the option to continue operating in certain future conditions. Similarly, new investment requires an expected net present value significantly greater than zero under such conditions, because there is option value in delaying investment. A graphical explanation of option value is shown below:

[9] *Investment Under Uncertainty*, Dixit and Pindyck, 1994, Princeton University Press.



If a decision cannot be deferred, there is no option value (because the option has expired) and a retirement should be made when the NPV of expected cost falls below the NPV of expected revenue, i.e., a benefit/cost ratio of one and a NPV equal to zero. But if a decision can be deferred, there is option value to waiting to see if prices and revenues increase. For example, if there is $50 million of option value, a utility would not retire at a benefit cost ratio of one, but at a benefit cost ratio of 0.56. Put another way, the utility would not exercise the option to retire a plant until the NPV cost of continued operation exceeds the option value of $50 million, i.e., a negative $50 million NPV of operation.

The flip side on new investment is that there is an option value to waiting to invest that is a mirror image of the option to retire—the expected NPV of investment must exceed the option value of waiting. As Dixit and Pindyck state:

> We will see that the optimal strategy for investment and abandonment, or for holding or exercising the two options, will take the form of two threshold prices, say P_H and P_L, with $P_H > P_L$. An idle firm will find it optimal to remain idle as long as P remains below P_H, and will invest as soon as P remains above P_H. An active firm will remain active as long as P remains above P_L, but will abandon if P falls to P_L. In the range of prices between the thresholds P_L and P_H, the optimal policy is to continue with the status quo, whether it be active operation or waiting.[10]

[10] *Id.*, at 216.

To put these insights into application for this IRP, I&M would need to determine the option value of waiting to invest and P_H for new plants such as renewables, and it would need to determine the option value of waiting to abandon and P_L for the Rockport units. I&M has made no effort to determine the value of these options, which can be quite high in a commodity industry like electric power. One need only look at how I&M's natural gas and power projections have changed between the last two IRPs to see that there is considerable value to not making irreversible decisions. Yet rather than valuing these options, I&M proposes to ends its lease on Rockport Unit 2 and replace it with renewables based on the naïve decision rule of expected NPV > 0 based on unreasonable assumptions of future lease costs and without considering the option value of flexibility.

I&M should be directed to reconsider its IRP using a market value for lease cost for Rockport Unit 2 and using tools that allow it to value portfolio flexibility, whether through option valuation or through evaluating dynamic portfolios that look at deferring Rockport abandonment year-by-year through the forecast period.

Renewables

The growth in renewables has created enormous system integration problems as the transmission requirements are different. For example, conditions in PJM could soon reflect those in MISO, where the best renewable resource areas lie. In 2010, MISO reclassified wind as a dispatchable intermittent resource (DIR) and recently announced it was considering the same classification for solar. As a DIR, wind became dispatchable, thereby changing the economics associated with wind generation. Further, MISO recently culled about 3.5 GW of renewable projects based on the need for expensive and lengthy transmission system upgrades.[11]

I&M states it did not consider incremental transmission costs stating "transmission expansion is so dependent upon location and factors beyond the Company's control, such as generation from entities external to I&M and conditions on interconnected systems, it is nearly impossible to determine a transmission-related avoided cost that has real meaning or is reliable for the Company other than on a very narrow, site-specific, case-by-case basis."[12] Clearly this is unacceptable given I&M reliance on renewables going forward. ICC recommends that the IURC require I&M to consider all renewable related costs, including transmission- and congestion-related costs in the context of portfolio alternatives before committing to large-scale reliance on renewable resources.

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[11] https://pv-magazine-usa.com/2019/11/13/miso-is-out-of-room-for-solar/

[12] IRP, Page 95

Natural Gas

I&M's selection of natural gas to become the primary source of generation over the long-term is problematic because of I&M's assumptions related to investment life, emission profile, technology, and costs. I&M concludes that natural gas is the economic replacement for both coal and nuclear baseload generation that is needed to support its system. Therefore, beginning in 2028 with the retirement of Rockport Unit 1, large quantities of natural gas CCGT are added. The net result is that by 2040 natural gas provides 40 percent of generation.

This result may not be least cost or consistent with a low carbon future. It may not be least cost if the technology costs associated with a 2028 investment in a conventional CCGT are not adjusted for the potential of a shorter than expected life. In other words, if the CCGT is retired prematurely under certain future CO_2 emission regimes, it could become a stranded asset for which ratepayers will still be asked to pay. Increasingly, petitions to purchase or construct large new natural gas plants are being rejected for this reason.

Recently Minnesota regulators unanimously rejected Xcel Minnesota's proposal to purchase a 720 MW natural gas plant, citing concerns the plant could close early and leave customers with hundreds of million of dollars in stranded asset costs.[13] This same concern was raised by the IURC when it rejected Vectren's proposed 850 MW natural gas plant. The IURC raised concerns that customers in the future could be "saddled with an uneconomic investment" given "an environment of rapid technological innovation."[14] I&M's proposed approach is similar to other proposed premature retirements of existing coal plants. Utilities are seeking full recovery of and on their investments despite the fact the coal plants have not been operated through their expected lives. Given I&M's apparent belief it needs base load generation to replace the Rockport and Cook plants, it is nonsensical for I&M to not retain the economically amortized Rockport Unit 2 as an option beyond 2028 as its transition to renewables rather than add new natural gas capacity with a high potential for becoming a stranded investment.

The alternative technology choice for I&M is natural gas with carbon capture.[15] The only new coal resource I&M is considering is coal with carbon capture and sequestration (CCS) as shown below.[16] This assumption ignores the current status of the New Source Performance Standards (NSPS) for Greenhouse Gases (GHG). In December 2018, EPA proposed revisions to the NSPS for GHG for new, modified, and reconstructed coal-fired electric utility generating units

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[13] https://www.minnpost.com/environment/2019/09/clean-energy-nonprofits-supported-xcel-energys-bid-to-buy-a-gas-plant-heres-why-minnesota-regulators-denied-them/

[14] Cause No. 45052, Apr. 24, 2019 Order, pp. 27-28.

[15] I&M suggested it was a technology under consideration in the IRP. The table of technology options does not include CCGT with carbon capture.

[16] IRP, Page 97

(EGUs). The proposal revised the determination of BSER based on the high costs and limited availability of CCS. EPA proposed to set limits for CO_2 emissions based on the most efficient demonstrated steam cycle in combination with the best operating practices. For large units, the BSER is proposed to be super-critical steam conditions, and if revised, the emission rate will be 1,900 pounds of CO_2 per megawatt-hour on a gross output basis (lb CO_2/MWh-gross). It is inconsistent to assume a CCS requirement for new coal but not new gas. Alternatively, it is inconsistent not to consider coal without CCS.

Table 15. New Generation Technology Options with Key Assumptions

Type	Capability (MW) (d)			Installed Cost (c,e)	Capacity Factor	LCOE (f)
	Std. ISO	Summer	Winter	($/kW)	(%)	($/MWh)
Base Load						
Nuclear	1,610	1,560	1,690	8,500	80	184.5
Pulv. Coal with Carbon Capture (PRB)	540	520	570	9,500	75	228.7
Combined Cycle (1X1 "J" Class)	610	800	820	900	75	60.4
Combined Cycle (2X1 "J" Class)	1,230	1,600	1,640	700	75	56.0
Combined Cycle (2X1 "H" Class)	1,150	1,490	1,530	700	75	56.9
Peaking						
Combustion Turbine (2 - "E" Class) (g)	180	190	190	1,200	25	151.7
Combustion Turbine (2 - "F" Class, w/evap coolers) (g)	490	500	510	700	25	118.4
Aero-Derivative (2 - Small Machines) (g)	120	120	120	1,100	25	138.7
Recip Engine Farm	220	220	230	1,300	25	130.6
Battery	10	10	10	1,900	25	161.3

In addition, I&M is understating the impact of its choice of natural gas on CO_2 emissions. I&M only includes inside the fence carbon emissions ignoring the upstream methane emissions despite the fact they have significantly greater global warming potential (GWP).[17] It is also inconsistent to taut the low carbon benefit of the use of gas post 2028 when the IRP itself shows this approach increases CO_2 emissions from 2029 through 2040.[18] Standard carbon analysis looks at life cycle emissions. Often referred to as Life Cycle Analysis, [19] this would include both downstream and upstream carbon emissions as well as emissions not in a particular year but over the life of the investment. If the life of Rockport Unit 2 is extended until 2035 and replaced by renewables, total CO_2 emissions would be lower compared to those of the new gas plants over their expected economic lives.

[17] https://netl.doe.gov/energy-analysis/details?id=3198. NETL finds CH_4 (methane) emissions have 87 times the GWP of CO_2. Page 18.

[18] IRP, Exhibit B, Page 8.

[19] Life Cycle Analysis (LCA) refers to an approach used to evaluate emissions over the lifetime of an investment as opposed to a discrete IRP-analysis period such as 20 years. An LCA also considers cradle to grave emissions related to a fuel source rather than only emissions at the power plant. The National Energy Technology Laboratory (NETL) of the U.S. Department of Energy is a leader in LCA having produced over 100 LCA reports. The most recent natural gas assessment entitled Life Cycle Analysis of Natural Gas Extraction and Power Generation was published in 2019 and is available for download at https://www.netl.doe.gov/energy-analysis/details?id=3198.

Further, the forecast of natural gas prices used by I&M in its analysis is too narrow. The outlook for natural gas prices is one of the greatest uncertainties in the IRP and, as such, the range in values between the base case and the high and low cases should be substantially greater that one standard deviation. The range in values can be seen in AEP's own forecasts. In September 2018, AEP for its Ohio Long-Term Forecast Report assumed a levelized cost of natural gas of $7.20 per MMBtu as shown below.[20]

EXHIBIT JFT-1
Page 9 of 47

Table 1. New Generation Technology Options with Key Assumptions

AEP System-East Zone
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)

Type	Capability (MW) (g) Std. ISO	Winter	Summer	Installed Cost (c,d) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost (f) ($/MBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Emission Rates SO2 (Lb/mmBtu)	NOx (Lb/mmBtu)	CO2 (Lb/mmBtu)	Capacity Factor (%)	Overall Availability (%)	LCOE (k) ($/MWh)
Base Load														
Nuclear	1,610	1,690	1,560	7,400	10,500	1.2	6.2	143.5	0.0000	0.000	0.0	90	94	171.7
Base Load (90% CO2 Capture New Unit)														
Pulv. Coal (Ultra-Supercritical) (PRB)	540	570	520	8,900	12,500	4.4	5.6	95.8	0.0650	0.050	21.3	85	90	244.0
Base / Intermediate														
Combined Cycle (1X1 "J" Class)	540	570	700	1,200	6,300	7.2	2.0	7.3	0.0007	0.007	117.1	60	89	87.2
Combined Cycle (2X1 "J" Class)	1,083	1,140	1,410	900	6,300	7.2	1.7	4.8	0.0007	0.007	117.1	60	89	78.7
Combined Cycle (2X1 "H" Class)	1,150	1,210	1,500	900	6,300	7.2	1.6	4.3	0.0007	0.007	117.1	60	89	75.9
Peaking														
Combustion Turbine (2 - "E" Class) (h)	182	190	190	1,200	11,700	7.2	3.9	9.4	0.0007	0.008	117.1	25	93	177.3
Combustion Turbine (2 - "F" Class, w/evap coolers) (h)	486	510	500	700	10,000	7.2	6.1	5.0	0.0007	0.008	117.1	25	93	139.3
Aero-Derivative (2 - Small Machines) (h,i)	120	120	130	1,400	9,700	7.2	2.4	36.9	0.0007	0.008	117.1	25	97	175.4
Recip Engines (12 - w/SCR, Natural Gas Only)	220	240	220	1,200	8,300	7.2	5.4	6.0	0.0007	0.008	117.1	25	98	148.0
Storage Battery (4 Hour-Lithium Ion)	10	10	10	2,200	87% (j)	--	--	142.3	--	--	--	25	99	275.0

Notes: (a) Installed cost, capability and heat rate numbers have been rounded
(b) All costs in 2018 dollars. Assume 2.17% escalation rate for 2018 and beyond
(c) $/kW costs are based on nominal capability
(d) Total Plant Investment Cost w/AFUDC (AEP-East rate of 5.5%,site rating $/kW)
(f) Levelized Fuel Cost (40-Yr. Period 2018-2057)
(g) All Capabilities are at 1,000 feet above sea level
(h) Includes Dual Fuel capability and SCR environmental installation
(i) Includes Black Start capability
(j) Denotes efficiency, (w/ power electronics)
(k) Levelized cost of energy based on assumed capacity factors shown in table

[20] http://dis.puc.state.oh.us/TiffToPDf/A1001001A18I19B54752F02019.pdf

But in the February 2019 I&M Stakeholder Workshop #3, I&M presented the same options but with natural at less than $3 per MMBtu.

AEP System
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)

Type	Capability (MW) (d) Std. ISO	Summer	Winter	Installed Cost (c,e) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost ($/MBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Capacity Factor (%)	LCOE (f) ($/MWh)
Base Load										
Nuclear	1,610	1,560	1,690	7,900	10,500	0.91	6.24	145.43	80	176.3
Pulv. Coal with Carbon Capture (PRB)	540	520	570	9,200	12,500	2.28	5.60	91.79	75	230.6
Combined Cycle (1X1 "J" Class)	540	700	720	1,000	6,300	2.94	1.97	10.81	75	62.3
Combined Cycle (2X1 "J" Class)	1,080	1,410	1,450	800	6,300	2.94	1.73	9.16	75	57.5
Combined Cycle (2X1 "H" Class)	1,150	1,490	1,530	700	6,300	2.94	1.63	8.65	75	55.8
Peaking										
Combustion Turbine (2 - "E" Class) (g)	180	190	190	1,200	11,700	2.94	3.94	17.60	25	145.9
Combustion Turbine (2 - "F" Class, w/evap coolers) (g)	490	500	510	700	10,000	2.94	6.07	15.77	25	114.0
Aero-Derivative (2 - Small Machines) (g,h)	120	120	120	1,400	9,900	2.94	2.44	18.93	25	143.8
Recip Engine Farm	220	220	230	1,300	8,300	2.94	2.61	6.32	25	123.0
Battery	10	10	10	1,900	87% (i)	0.00	0.00	38.99	25	175.8

Notes: (a) Installed cost, capability and heat rate numbers have been rounded
(b) All costs in 2018 dollars, except as noted.
(c) $/kW costs are based on summer capability
(d) All Capabilities are at 1,000 feet above sea level
(e) Total Plant Investment Cost w/AFUDC (AEP-East rate of 5.5%,site rating $/kW)
(f) Levelized cost of energy based on capacity factors shown in table
(g) Includes Dual Fuel capability and SCR environmental installation
(h) Includes Black Start capability
(i) Denotes efficiency, (w/ power electronics)

And in the filed July 2019 IRP, the fuel cost assumptions for natural gas are back up to $3.42 as shown below:

AEP System
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)

Type	Capability (MW) (d) Std. ISO	Summer	Winter	Installed Cost (c,e) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost ($/MBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Capacity Factor (%)	LCOE (f) ($/MWh)
Base Load										
Nuclear	1,610	1,560	1,690	8,500	10,500	0.94	3.99	168.33	80	184.5
Pulv. Coal with Carbon Capture (PRB)	540	520	570	9,500	12,500	2.42	4.37	104.12	75	228.7
Combined Cycle (1X1 "J" Class)	610	800	820	900	6,200	3.42	1.77	12.86	75	60.4
Combined Cycle (2X1 "J" Class)	1,230	1,600	1,640	700	6,200	3.42	1.55	10.65	75	56.0
Combined Cycle (2X1 "H" Class)	1,150	1,490	1,530	700	6,300	3.42	1.51	11.07	75	56.9
Peaking										
Combustion Turbine (2 - "E" Class) (g)	180	190	190	1,200	11,700	3.42	4.05	30.46	25	151.7
Combustion Turbine (2 - "F" Class, w/evap coolers) (g)	490	500	510	700	10,000	3.42	6.27	24.55	25	118.4
Aero-Derivative (2 - Small Machines) (g)	120	120	120	1,100	9,900	3.42	2.51	32.17	25	138.7
Recip Engine Farm	220	220	230	1,300	8,300	3.42	5.36	13.91	25	130.6
Battery	10	10	10	1,900	83% (h)	0.00	0.00	38.99	25	161.3

Notes: (a) Installed cost, capability and heat rate numbers have been rounded
(b) All costs in 2019 dollars, except as noted.
(c) $/kW costs are based on summer capability
(d) All Capabilities are at 1,000 feet above sea level
(e) Total Plant Investment Cost w/AFUDC (AEP-East rate of 5.5%,site rating $/kW)
(f) Levelized cost of energy based on capacity factors shown in table
(g) Includes SCR environmental installation
(h) Denotes efficiency, (w/ power electronics)

In other words, in less than a 12-month period, the AEP Fundamentals assumption for natural gas has ranged from a levelized cost of over $7 per MMBtu to less than $3 per MMBtu. There are reasons why natural gas prices could go lower, as well higher. The range in the natural gas price assumptions demonstrate (1) the uncertainty and (2) why more than one standard deviation range makes sense.

CO_2 Costs

Other than the single "No CO_2" case, all of I&M's commodity forecasts assume as a certainty that a CO_2 tax will be imposed in 2028, resulting in a step function increase in avoided energy costs and in the cost of fossil fuel inputs. The "No CO_2" case is a variant of the base case and does not reflect the lower commodity cost that was discussed above. As a result, most of the commodity variants assume that portfolios are evaluated over their entire lives with CO_2 costs beginning in 2028. This is a problem when I&M does not allow flexibility for the portfolios to evolve with changing market conditions.

CONCLUSIONS AND RECOMMENDATIONS

Conclusions

The Preferred Plan in I&M's IRP assumes the lease for Rockport Unit 2 is not renewed when in expires in 2022, Rockport Unit 1 is retired in 2028, which I&M committed to in the Fifth Modification to the Consent Decree (Fifth Modification), and Cook nuclear units 1 and 2 are retired when their current operating permits end—2034 and 2038 respectively. These resources would be replaced by a combination of solar, energy storage, energy efficiency, and short-term market purchases through 2028 and thereafter by natural gas, solar, and battery storage. There are numerous deficiencies in I&M's IRP, several of which are fatal to its conclusions, including:

1. The effects of the Fifth Modification are not explicitly incorporated into the IRP;
2. The IRP does not calculate the cost of I&M's agreement in the Fifth Modification to retire Rockport Unit 1 no later than 2028, which results in a loss of option value to continue operating the unit;
3. The assumed lease renewal price for Rockport Unit 2 is grossly inflated without justification;
4. I&M did not include in the IRP a cost associated with the loss of a Rockport option in 2028 as part of its Rockport Unit 2 lease extension valuation;
5. I&M explicitly did not consider the cost of transmission upgrades required to accommodate the growth in renewables;

6. I&M did not appropriately consider all of the potential costs of the proposed natural gas-fired combined cycle additions;
7. I&M did not perform any Life Cycle Analysis associated with the addition of the natural gas combined-cycle plants; and
8. I&M inappropriately limited its scenario analysis of the speculative costs of carbon dioxide emissions.

Recommendations

ICC recommends the IURC find that absent an update to its IRP, I&M cannot use the IRP as a justification for related cost recovery or for future resource additions. ICC believes the update should incorporate, at a minimum, the following:

1. Reasonable assumptions regarding Rockport Unit 2, including market-based lease extension costs and/or the cost of I&M repurchasing the unit;
2. The option value of retaining a unit at Rockport beyond 2028;
3. A quantification of the incremental costs of compliance associated with the Fifth Modification as compared to the costs of compliance associated with the Third Modification;
4. Factoring transmission- and congestion-related costs into the analysis of renewables;
5. An assumed 15-year life for the natural gas additions in more environmentally restrictive scenarios;
6. The cost of the natural gas additions, including carbon capture;
7. A range in natural gas prices beyond plus or minus one standard deviation;
8. Life cycle analysis of CO_2 (carbon equivalent) emissions related to the Preferred Plan; and
9. A range of CO_2 emissions cost regimes in the scenario analyses.

EXHIBIT 1

Consent Decree Violation	**Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)**
a. Failure to pay the civil penalty as specified in Section IX (Civil Penalty) of this Consent Decree	$10,000 per day
b. Failure to comply with any applicable 30-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency, Emission Rate for PM, or Other SO_2 Measures where the violation is less than 5% in excess of the limits set forth in this Consent Decree	$2,500 per day per violation
c. Failure to comply with any applicable 30-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency, Emission Rate for PM, or Other SO_2 Measures where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree	$5,000 per day per violation
d. Failure to comply with any applicable 30-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency, Emission Rate for PM, or Other SO_2 Measures where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree	$10,000 per day per violation

Consent Decree Violation	Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)
e. Failure to comply with the Eastern System-Wide Annual Tonnage Limitation for SO_2	\$5,000 per ton for the first 1000 tons, and \$10,000 per ton for each additional ton above 1000 tons, plus the surrender, pursuant to the procedures set forth in Paragraphs 82 and 83, of NO_x Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
f. Failure to comply with the Plant-Wide Annual Rolling Tonnage Limitation for SO_2 at Clinch River	\$40,000 per ton, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96, of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
g. Failure to comply with the Eastern System-Wide Annual Tonnage Limitation for NO_x	\$5,000 per ton for the first 1000 tons, and \$10,000 per ton for each additional ton above 1000 tons, plus the surrender, pursuant to the procedures set forth in Paragraphs 82 and 83, of NO_x Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
h. Failure to install, commence operation, or Continuously Operate a pollution control device required under this Consent Decree	\$10,000 per day per violation during the first 30 days, \$32,500 per day per violation thereafter
i. Failure to Retire, Retrofit, or Re-power a Unit by the date specified in this Consent Decree	\$10,000 per day per violation during the first 30 days, \$32,500 per day per violation thereafter

Consent Decree Violation	Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)
s. Failure to fund an Environmental Mitigation Project, as submitted by the States, in compliance with Section VIII (Environmental Mitigation Projects) of this Consent Decree	$1,000 per day per violation during the first 30 days, $5,000 per day per violation thereafter
t. Failure to Continuously Operate required Other NO_x Pollution Controls required in Paragraph 69	$10,000 per day during the first 30 days, and $32,500 each day thereafter
u. Failure to comply with the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer	$40,000 per ton, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96 of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
v. Any other violation of this Consent Decree	$1,000 per day per violation

Third Modification

Consent Decree Violation	Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)
x. Failure to comply with the Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport	$40,000 per ton, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96, of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
y. Failure to fund a Citizen Plaintiffs' Mitigation Project as required by Paragraph 119B of this Consent Decree	$1,000 per day per violation during the first 30 days, $5,000 per day per violation thereafter
z. Failure to implement the Citizen Plaintiffs' Renewable Energy Project required by Paragraph 128A of this Consent Decree	$10,000 per day per violation during the first 30 days, $32,500 per day per violation thereafter