COMMENTS OF CITIZENS ACTION COALITION, EARTHJUSTICE, INDIANA DISTRIBUTED ENERGY ALLIANCE, MICHAEL A. MULLETT, SIERRA CLUB, AND VALLEY WATCH ON DUKE ENERGY INDIANA'S AND I&M'S 2015 IRPs

INTRODUCTION

Pursuant to the Indiana Utility Regulatory Commission's ("IURC" or "Commission") Integrated Resource Planning Rule, 170 IAC 4-7[1] and P.L. 246-2015 (Senate Enrolled Act 412-2015), Citizens Action Coalition of Indiana, Earthjustice, Indiana Distributed Energy Alliance ("IndianaDG"), Michael A. Mullett, Sierra Club, and Valley Watch (collectively, "Commenters") hereby submit the following comments on the 2015 Integrated Resource Plans ("IRP") submitted by Duke Energy Indiana ("Duke") and Indiana Michigan Power Company ("I&M").

As the 2014 IRP Final Report observed, "[w]ith the passage of P.L. 246-2016 (SEA 412-2015) on May 6, 2015, Indiana law now explicitly requires long-term resource planning for the State of Indiana."[2] Although the Commission's IRP Rule, 170 IAC 4-7 is currently undergoing a rulemaking (IURC RM# 15-06) pursuant to the mandates of SEA 412, the October 4, 2012 version of the Proposed IRP Rule recognizes the increasing regional interconnectedness of Indiana utilities, and facilitates a collaborative process for evaluating a range of risks and uncertainties facing the electric sector, such as increasingly stringent environmental regulations (including regulation of greenhouse gas emissions) and increasingly low-cost and available demand-side and renewable resources.[3] As Commission Staff found in evaluating the 2014 IRPs, "the IRP is evolutionary and the expectation is for continual improvements in tools, processes, and analysis in response to increased risks and attendant [sic] costs."[4]

Commenters have organized their comments based on an evaluation of the Duke and I&M IRPs' compliance with specific informational, procedural, and methodological requirements of the 2012 draft proposed IRP rule. These comments are not meant to be exhaustive reviews of each utility's IRP process, resource planning practices, or preferred resource plans, but instead seek to highlight specific deficiencies that Commenters have identified with the IRPs. Commenters respectfully request that Commission Staff call on Duke and I&M to address these informational, procedural, and methodological deficiencies both in

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[1] All references to the Commission's IRP Rule, 170 IAC 4-7, refer to the revised draft of the Proposed IRP Rule, which the Commission circulated on October 4, 2012 in the IRP rulemaking, RM# 11-07. As explained in the Electricity Director's Final Report on the 2014-2015 Integrated Resource Plans ("2014 IRP Final Report"), p. 1 (June 10, 2015), available at http://www.in.gov/iurc/files/Director_2013_IRP_Report_-_Final_4-30-14.pdf, both Commission staff and utilities have decided to move forward with the IRP process set forth in the draft proposed rule as if the rule were in effect.

[2] 2014 IRP Final Report at 1.

[3] *Id.* at 3.

[4] *Id.* at 4.

response to the Commission Staff's draft report and in any future resource planning and decision making.

Finally, Commenters wish to express appreciation to staff at Duke and I&M for their willingness to provide responses to informal discovery requests following the submission of Duke and I&M's IRPs that assisted Commenters in understanding each utility's IRP process. However, Commenters were unable to obtain critical information from the company, Energy Exemplar, who owns Plexos, the modeling software which I&M used for its IRP. In particular, Energy Exemplar refused to provide the instruction manual and certain inputs for Plexos. It is untenable for the public not to have access to the instruction manual for the resource optimization model that a utility uses for its IRP. In the future, I&M should either directly provide or facilitate production of such information or use another modeling platform that provides such information.

COMMENTS

A. Resource Integration Requirements: Utilities must demonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis. (*170 IAC 4-7-8(b)(3)*).

The IRP Rule requires that energy efficiency and other demand-side resources be treated on equal footing with supply-side resources. 170 IAC 4-7-8(b)(3). Utilities must conduct their resource modeling so that the model can select energy efficiency whenever it is the optimal resource, rather than being hard-wired into the analysis in such a way that it cannot compete with other resources. While there are several, legitimate ways to accomplish this goal, "it is indisputable that utilities in their IRPs must attempt to evaluate supply-side and demand-side resources in something resembling a comparable manner."[5]

<u>I&M</u>

1. I&M Failed to Evaluate Energy Efficiency and Demand Response in a Manner That is Consistent With and Comparable to Its Evaluation of Supply-Side Resources.

The accompanying Report identifies two major flaws in I&M's consideration of energy efficiency and demand response in its IRP. First, the IRP unreasonably limits the amount of efficiency and demand response resources available to the model. I&M unreasonably excluded certain efficiency measures that are in its current DSM plan and other readily available and cost-effective measures. *See* Report at 10-13. Second, I&M subjected energy efficiency for an additional economic screening—before I&M included energy efficiency measures in the model it first removed measures that it believed were not cost-effective. Instead of pre-screening measures to predetermine whether it was cost-effective, I&M should have allowed the model to

[5] 2013 IRP Report at 4-5.

select from all of the efficiency measures which ones were cost-effective in order to find the optimal amount of efficiency—as the model did for all other resources. We have previously criticized the use of cost-effectiveness tests to screen out efficiency measures rather than allowing the optimization model to select from all the measures identified in the analysis of technical potential.[6] I&M's IRP illustrates the impact of this flawed methodology.

These flaws likely lead the IRP to significantly underestimate the optimal amount of energy efficiency, thereby resulting in a preferred plan that fails to fully take advantage of the least-cost resource, efficiency.

2. I&M Failed to Treat Renewable Resources in a Manner Comparable to the Way It Treated Other Supply-Side Resources.

I&M's modeling assumptions stacked the deck against wind and solar, in violation of the IRP rule requirement that supply- and demand-side resources all be treated consistently and comparably. *See* 170 IAC 4-7-8(b)(3). In particular, I&M assumed that the production tax credit for wind projects ends in 2016. *See* I&M IRP at 108. I&M made a similar assumption for the solar investment tax credit, except in the Fleet Modification Prime and New Carbon Free cases. *See id.* at 114. This modeling assumption does not reflect the actual PTC that exists today. On December 15, 2015, Congress extended the Wind PTC for another five years. Under this bill, the PTC would maintain at its current level through 2016 and start phasing down at 80% of its present value in 2017, 60% in 2018 and 40% in 2019. By failing to model the PTC for these four additional years, I&M likely failed to leverage cheaper wind resources. Congress also extended the tax credits for solar through January 1, 2022.[7]

While Congress extended these tax credits after I&M submitted its IRP, various stakeholders urged I&M to model scenarios and/or sensitivities in which both the Production Tax Credit for wind and Investment Tax Credit for solar were extended.[8] Stakeholders made this recommendation on the basis of the widespread belief that Congress would extend the tax credits. I&M's failure to model an extension of the ITC across all scenarios in which the tax credit is extended was unreasonable, even judged at the time I&M made its decision. Studies for other utilities completed in 2015 modeled renewables costs under a variety of tax credit scenarios, as the stakeholders here suggested.[9] Moreover, I&M modeled sensitivities for several

[6] Joint Commenters' Reply Comments for 170 IAC 4-7, 4-8 Rulemaking, http://www.in.gov/iurc/files/RM_15_06_Joint_Commenters_Reply_Comments.pdf.

[7] H.R. 2029, Consolidated Appropriations Act of 2016, Title III, §§ 301, 303, *available at* https://www.gpo.gov/fdsys/pkg/BILLS-114hr2029enr/pdf/BILLS-114hr2029enr.pdf.

[8] I&M acknowledges in the IRP that stakeholders recommended modeling solar based on the expectation that the Investment Tax Credit would be extended. I&M IRP at p. ES-4.

[9] *See, e.g.*, The Brattle Group, Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Company's Service Territory, at 8 (July 2015), *available at* http://brattle.com/system/publications/pdfs/000/005/188/original/Comparative_Generation_Costs_of_Utility-Scale_and_Residential-Scale_PV_in_Xcel_Energy_Colorado%27s_Service_Area.pdf?1436797265.

key variables, such as fuel prices, and I&M should, at a minimum, have modeled sensitivities for all portfolios that varied the tax credits, given the importance of the credit to the economics of renewables projects.

The net effect of I&M's unreasonable assumption that the tax credits would not be extended is that, for most of the cases modeled, wind and solar resources have higher costs in the model than in reality. For example, a study for Xcel Energy in Colorado found that increasing the Investment Tax Credit from 10% to 30% decreased the cost of utility-scale solar from $83 MWh to $66 MWh, or a decrease of roughly 20%.[10] And I&M estimates a reduction of $23 per MWh of wind associated with the production tax credit.[11]

By unreasonably failing to account for the extension of the Investment and Production Tax Credits, I&M stacked the deck against wind and solar, which resulted in a plan with fewer renewable projects than would otherwise have occurred. This violates I&M's obligation to evaluate renewables on a level playing field with other resources. *See* 170 IAC 4-7-8(b)(3).

3. I&M Constrained the Model from Adding Reasonable Amounts of Wind and Solar.

I&M established several constraints on the amount of wind and solar resources that the model could select in each year, as well as over the entire analysis period. The model could not select more than 50 MW of solar each year. I&M IRP at 107, 113. The model could not add more than 300 MW of wind each year, and could not add more than 1400 MW of wind over the entire planning period. *Id.* at 108, 113. Finally, the model was set up so that renewables could not represent more than 30% of I&M's total capacity in any given year. *Id.* at 108.

Preventing the model from selecting more than 50 MW of solar in any given year is problematic because, as with most resources, there are economies of scale for solar projects. While there is some debate in the literature, studies have found that the cost of utility-scale solar declines as the size of the project increases, at least up to a project size of approximately 100 MW.[12] Moreover, it is common for utilities to build solar projects larger than 50 MW.[13] And

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[10] *Id.*

[11] Based on I&M spreadsheet Wind Bundle Costs.

[12] United States Department of Energy, Photovoltaic System Pricing Trends at 23 (Sept. 22, 2014), *available at* http://www.nrel.gov/docs/fy14osti/62558.pdf; *see also* Mark Bollinger and Joachim Seel, Lawrence Berkeley National Laboratory, Utility-Scale Solar 2014, at 16 n.23 (Sept. 2015), *available at* https://emp.lbl.gov/sites/all/files/lbnl-1000917.pdf. ("These empirical findings more or less align with recent modeling work from NREL (Fu et al. 2015), which also finds only modest scale economies for a 100 MW project compared to a 10 MW project, and no additional scale economies for projects larger than 100 MW.")

[13] United States Department of Energy, Photovoltaic System Pricing Trends at 23 (Sept. 22, 2014), *available at* http://www.nrel.gov/docs/fy14osti/62558.pdf.

with the Investment Tax Credit for solar projects set to decline after 2020, it is economically rational to build larger solar projects now. By limiting the model to 50 MW of new solar in each year, I&M both (1) unreasonably limited the amount of solar that the model could select, and (2) unreasonably increased the cost of solar projects, given the economies of scale for projects less than 100 MW.

In addition, it is not clear how I&M reached its decision to constrain the model from selecting more than 300 MW of wind in each year. According to I&M, "[t]his cap is based on the DOE's Wind Vision Report chart on page 12 of the report which suggests from numerous transmission studies that transmission grids should be able to support 20% to 30% of intermittent resources in the 2020 to 2030 timeframe." I&M IRP at 108. It is true that PJM concluded that it would be possible for PJM as a whole to support a scenario in which 30% of energy within PJM is generated by renewable resources. But there is nothing in the PJM Wind Vision Report that suggests that any individual utility could not integrate more than 300 MW of wind in a particular year. Nor is it clear how I&M took PJM's conclusion about 30% of electricity across all of PJM coming from renewable sources and translated that into a prohibition on adding more than 300 MW of wind in a given year. At a minimum, I&M's modeling constraint on annual wind additions is unexplained. At worst, it functions as an arbitrary limit on the amount of wind the model can select in a given year.

4. I&M's Modeling Results Call into Question Whether Both Rockport Units Are Needed to Serve I&M's Native Load Customers, and Whether the Rockport Units Generate Revenues Sufficient to Cover Their Costs.

I&M's modeling results indicate that I&M expects to make large numbers of off-system sales of electricity throughout the planning period. Indeed, as explained in the attached Report, the off-system sales exceed the generation from Rockport Unit 2 in every year of the planning period. Report at 47-52. This means that if Rockport Unit 2 were not generating any electricity, I&M could still meet the energy requirements of the retail customers in its territory that I&M is obligated to serve. Even if Rockport Unit 2 is needed for capacity, not energy, the question is whether it would be more economic to retire Rockport Unit 2 and replace it with a lower cost capacity resource than to spend over $[redacted] to retrofit Rockport Unit 2 for environmental compliance.

Given that I&M's off-system sales exceed the generation from Rockport Unit 2, one could view Rockport Unit 2 as essentially a merchant plant. For Rockport Unit 2 to benefit customers, and in particular, to justify further expenditures to extend its operating life, Rockport Unit 2 should generate revenues that at least exceed total generation costs.

However, revenues from Rockport Unit 2 are less than its fixed and variable costs. *See* Report at 52-55. Moreover, the revenues reported in the modeling results overstate the revenues credited to customers, because I&M did not account for the fact that I&M shareholders keeps at least 50% of off-system sale margins that are above $37.5 million. *Id.* at 55-56. In addition, revenues are likely overstated because I&M assumes that the Rockport units' heat rate improves over time—an unfounded assumption. *Id.* at 56-57. All other things being equal, PJM would dispatch a unit with a lower heat rate more frequently due to its lower variable costs. Thus, the use of an unexplained and overly optimistic heat rate leads to inaccurately high generation and revenues for Rockport Unit 2.

5. I&M's IRP Uses Natural Gas Prices that Are Unreasonably High.

Fuel prices are one of the most important inputs in an IRP, because the fuel costs comprise the majority of the variable costs of coal and natural gas units. Thus, the relative cost of coal compared to natural gas goes a long way to determining the dispatch of coal and gas units. I&M's IRP forecasts natural gas prices at the Henry Hub of $4.34/MMBtu in 2016 and $5.09/MMBtu in 2017, and continuing to increase thereafter.[14] This is well above the most recent projections from EIA, which are $2.65/MMBtu in 2016 and $3.22/MMBtu in 2017.[15] Using unreasonably high natural gas prices skews the modeling results in favor of more coal generation.

6. I&M's 2015 IRP Repeats Its Failure to Consider the Environmental Costs and Risks Facing the Clifty Creek and Kyger Creek Plants.

In our comments submitted on I&M's 2013 IRP, we noted that I&M had failed to identify and evaluate the environmental costs and risks facing the Clifty Creek and Kyger Creek plants, of which I&M owns an 18% share.[16] I&M's 2015 repeats those mistakes. I&M's 2015 IRP contains absolutely no discussion of the future costs or risks facing the OVEC Clifty Creek and Kyger Creek power plants, despite the fact that I&M owns approximately 18% of those plants' capacity, I&M IRP at 33, and intends to rely on purchases of power from the plants to serve its customers throughout the planning period. Both the Clifty Creek and Kyger Creek plants are expected to face significant costs associated with compliance with EPA's Effluent Limitation Guidelines and Coal Combustion Residuals Rules, among other environmental requirements.

Information concerning future costs and risks facing the OVEC plants is undeniably relevant to "the balance of costs and risks" facing I&M's preferred resource portfolio, of which the OVEC plants are an integral part. The requirements in 170 IAC 4-7-8(b)(7) that I&M both identify and explain its assumptions concerning risks and uncertainties with its preferred resource portfolio, and also quantify those risks and uncertainties where possible, applies equally to all "resources" in the Company's portfolio – which includes the Clifty Creek and Kyger Creek plants. *See* 170 IAC 4-7-1(oo) ("'Resource' means a facility, project, contract, or other mechanism used by a utility to provide electric energy service to the customer."); *id*. (current)

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[14] I&M spreadsheet "2015H1_LTF_FT_Base_Nominal_2015_04_24," tab "Annual Prices."

[15] United States Energy Information Admininstration, Short-Term Energy Outlook (Jan. 12, 2016), *available at* http://www.eia.gov/forecasts/steo/report/natgas.cfm.

[16] Comments of Citizens Action Coalition, Earthjustice, and Sierra Club on I&M's 2013 IRP, at 40-42 (Jan. 2014).

(same definition). I&M's failure to include in this IRP any evaluation of the future environmental requirements or any other future costs or risks facing the OVEC plants throughout the planning period violates this requirement of the Commission's IRP rules.

Moreover, not only does I&M fail to identify, let alone attempt to quantify, the costs and risks facing this resource, I&M also does not appear to have considered in this IRP process any alternative resource portfolios that do not include purchases of power from the two OVEC plants. Rather, I&M appears to assume in this IRP, without explanation, that purchases of power from the OVEC plants are "off the table" for the purposes of this planning process, and thus that it will continue purchasing power from the OVEC plants under all possible futures. This also violates the Commission's proposed IRP rule, which requires I&M to "consider continued use of an existing resource as a resource alternative in meeting future electric service requirements" rather than assuming that any of its existing resources will continue to be utilized in the future. 170 IAC 4-7-6(a).

Duke

1. Duke Failed to Evaluate Energy Efficiency and Demand Response in a Manner that is Consistent With and Comparable to Its Evaluation of Supply-Side Resources.

Duke's IRP significantly underestimates the optimal amount of energy efficiency and demand response resources as a result of two major flaws. First, as described in the accompanying Report, Duke made unreasonably low amounts of energy efficiency available to the model. Report, pp. 5-10. Second, Duke, like I&M, prescreened energy efficiency resources available to the model. *Id.*, pp. 19-24. As described in greater detail in the Report, these flaws result in Duke's IRP significantly underestimating the amount of cost-effective energy efficiency that should be included in the preferred plan. The end result is a preferred portfolio that misses opportunities to pursue the least-cost resource, efficiency.

2. Duke's Treatment of Renewable Resources Is Riddled with Errors and Systematically Biases the Analysis against Wind and Solar.

Duke's IRP suggests that Duke simply does not take renewable resources seriously, at least in Indiana. Duke's evaluation of wind and solar resources has four fundamental flaws: (1) Duke assumed that the cost of solar will be unchanged for 20 years, despite the fact that solar costs have decreased by more than 50% in the last seven years and that virtually every analyst predicts solar costs will continue to decline; (2) Duke uses an unreasonably low capacity factor for wind that is apparently based on only a single wind project; (3) Duke assumed that Congress did not renew the tax credits for wind and solar, when in fact Congress extended both tax credits; and (4) Duke made a sweeping statement that renewables are not economic without "subsidies," revealing Duke's views that renewables are fundamentally different than other supply-side resources. The combination of these errors and biases means that Duke's IRP has almost no value or credibility concerning wind and solar resources, and violates the IRP Rule requirement to treat all supply and demand resources on a consistent and comparable basis. *See* 170 IAC 4-7-8(b)(3).

First, Duke uses capital costs for wind and solar that are unreasonably high, based on projected price declines and significantly lower wind and solar costs used by other Indiana utilities. For solar, Duke uses a cost of $[redacted] per kilowatt in 2016, which remains flat through the analysis period. The notion that solar costs will remain flat for 20 years is patently unreasonable, based on the historical trajectory of solar prices and the forecasts of other analysts.

Empirical studies of the installed cost of utility-scale solar projects have concluded that between 2007 and 2014, solar costs declined by more than 50%.[17] Many, if not most, analysts expect the cost of solar power to continue to decline. For example, a 2015 study for a Colorado utility, Xcel Energy, used the historical rate of decline in solar costs and projected that rate forward in order to estimate the cost of utility-scale solar projects in the future.[18] Here in Indiana, at the same time that Duke submitted an IRP that assumed solar costs would remain flat for the entire analysis period, *see* Report at 25-28, I&M used solar prices that decline by more than 40% during the analysis period, *see* I&M IRP at 106.

In short, the inputs that Duke used for the cost of utility-scale solar are anomalous; we are not aware of any other utility, agency, or consultancy that predicts that utility-scale solar costs will remain unchanged for the next 20 years. Given that Duke has not advanced any rationale for ignoring the historical decline in solar costs and departing from the consensus that solar costs will likely continue to decline, Duke's solar costs should be viewed as unreasonably high.

Second, Duke assumed a capacity factor for wind of [redacted]%, *see* Report at 25-28, which, at best, is not adequately supported, and, at worst, is unreasonably low. The assumed capacity factor has a significant impact on the economics of a wind project, because the higher the number of hours during which the project generates electricity, the lower the levelized cost of electricity from the project, and vice versa. As explained in the accompanying Report, Duke appears to have based its capacity factor for wind on a single wind project in Indiana, the Benton County Wind Farm, which has achieved capacity factors at the low end of the spectrum. The Headwaters wind project, one of Indiana's newest wind projects, is anticipated to achieve a much higher capacity factors than [redacted]%, which is why I&M assumed a capacity factor range of 40 - 45%. *See* I&M IRP at 108. Other wind projects in neighboring states have achieved higher capacity factors than [redacted]% as well, and there is no reason that Duke should limit its evaluation of wind to only projects that can be built in Indiana. Finally, the wind industry is evolving rapidly, as turbines become larger and able to harvest wind from sites that previously could not be

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[17] Mark Bollinger and Joachim Seel, Lawrence Berkeley National Laboratory, Utility-Scale Solar 2014, at p. i (Sept. 2015), *available at* https://emp.lbl.gov/sites/all/files/lbnl-1000917.pdf.

[18] *See, e.g.*, The Brattle Group, Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Company's Service Territory, at 19 (July 2015), *available at* http://brattle.com/system/publications/pdfs/000/005/188/original/Comparative_Generation_Costs_of_Utility-Scale_and_Residential-Scale_PV_in_Xcel_Energy_Colorado%27s_Service_Area.pdf?1436797265.

developed for wind energy. Given the long-term nature of the IRP, it would have been prudent to account for this trend in wind technologies. In sum, Duke has not justified the use of a capacity factor that is below what other projects in Indiana and surrounding states have achieved.

Third, Duke made the same mistake as I&M by unreasonably failing to account for the possible extension of the tax credits for wind and solar projects. Report, pp. 25-28. As mentioned above, and as described in the accompanying Report, in December 2015, Congress extended the production tax credits for wind projects such that the credits are phased out by January 1, 2020 and extended the investment tax credit for solar projects so that the solar tax credit is phased out by January 1, 2022. By assuming that the unavailability of tax credits during years when they will actually be available, Duke unreasonably increased the cost of wind and solar in its modeling. The model thus underestimated the amount of cost-effective renewables to add to the portfolio.

Fourth, Duke's IRP states that, "[a]side from their technical limitations, solar and wind technologies are not currently economically competitive without State and Federal subsidies." Duke IRP at 100. This statement shows a significant bias against solar and wind technologies. A utility's obligation is to provide for low cost, reliable electricity. It is irrelevant why a resource is economic. There is nothing in the IRP Rule, other Commission rules, or Indiana law that instructs a utility to base its resource planning on an evaluation of whether resources are provided with tax credits or otherwise incentivized by state or federal law.

Moreover, Duke's statement ignores the substantial "subsidies" provided to other supply-side resources, including natural gas and coal. For example, the federal government recently announced a moratorium on new coal leases on federal lands[19] after long-standing criticisms that coal was being subsidized by being leased at below-market rates.[20] Duke's statement implies that wind and solar resources are the only resources that receive any kind of "subsidy," which is demonstrably false.

Taken together, these fundamental flaws in Duke's analysis of renewables violate Duke's obligation to evaluate all supply- and demand-side resources on a consistent and comparable basis. *See* 170 IAC 4-7-8(b)(3). These flaws make the IRP's conclusions regarding renewables completely unreliable. Commission Staff should instruct Duke that the systematic flaws in Duke's consideration of renewables mean that the decisions in this IRP regarding renewables cannot serve as the basis for any future planning decisions. Commission Staff should also

[19] Joby Warrick, OBAMA ANNOUNCES MORATORIUM ON NEW FEDERAL COAL LEASES, Washington Post, Jan. 15, 2016, *available at* https://www.washingtonpost.com/news/energy-environment/wp/2016/01/14/obama-administration-set-to-announce-moratorium-on-some-new-federal-coal-leases/.

[20] *See, e.g.*, Government Accountability Office, Report GAO-14-140 (Dec. 2013), available at http://www.gao.gov/assets/660/659801.pdf; Headwaters Economics, An Assessment of U.S. Federal Coal Royalties (Jan. 2015), *available at* http://headwaterseconomics.org/wphw/wp-content/uploads/Report-Coal-Royalty-Valuation.pdf.

instruct Duke that it is expected to evaluate renewable resources using reasonable cost assumptions, rather than using a series of implausible assumptions that stack the deck against renewables.

3. Several of Duke's Modeling Assumptions Bias the Results in Favor of Its Existing Coal Units.

As explained in the accompanying Report, Duke made two sets of assumptions regarding its existing coal units that bias the modeling results in favor of selecting the existing coal units over other resources, and Duke should be required to update its IRP. First, while Duke claims to have used a carbon dioxide emissions cap and related price to simulate compliance with the Clean Power Plan, most portfolios exceed the purported emissions "cap" in most years. *See* Report, pp. 63-64. Thus, it is unclear how exactly Duke set up the modeling in order to account for regulation of greenhouse gas emissions under the Clean Power Plan. Failure to account for the Clean Power Plan's impacts benefits coal units the most, given that coal units emit greenhouse gases at far higher rates than other resources.

Second, Duke assumed, without adequate explanation, that the Gallagher and Edwardsport plants would have lower heat rates than the plants achieved in 2014. *See* Report, pp. 66-67. This is especially true for Gallagher Unit 4 and Edwardsport. *See id.* The heat rate assumed for modeling purposes has a significant effect on a unit's economics, because a decline in heat rate means that the unit is more efficient, i.e., that it can generate a given amount of electricity with a lower heat input.

Even though Duke used a carbon "cap" that does not appear to actually limit carbon emissions, and used optimistic heat rates, several of the Gallagher and Gibson units are not profitable. In every year between 2015 and 2019, Duke's modeling projects that Gallagher Units 2 and 4 will incur fixed and variable costs that exceed their market revenues. *See* Report, 67-69. This continues the trend from 2009-2014, during which Gallagher Units 2 and 4 had net negative profits in four of six years. *See id.* Similarly, Gibson Unit 5 is projected to incur fixed and variable costs that exceed the revenues they generate between 2015 and 2019. *See id.*

Additionally, Edwardsport's heat rate is optimistically high in Duke's IRP modeling with Duke assuming that the plan will finally emerge from its history of frequent outages and technical programs. *Id*. at 66.

B. Resource Integration Requirement: Utilities must demonstrate how the preferred resource portfolio balances cost minimization with cost-effective risk and uncertainty reduction. (*170 IAC 4-7-8(b)(7)*).

I&M

1. I&M's IRP Misrepresents the Modeling Results by Failing to Mention that Its Preferred Portfolio is not the Least-Cost Option.

The IRP Rule requires each utility to present the results of testing and ranking resource portfolios according to the present value of revenue requirements, or PVRR, and risk metrics. 170 IAC 4-7-8(b)(7)(D). While the IRP Rule does not dictate which resources a utility chooses to pursue in its preferred plan, the IRP Rule is meaningless if utilities are free to misrepresent costs and revenue requirements.

I&M's IRP contains a glaring omission: the text fails to mention that I&M's preferred portfolio is not the least-cost option. We have been unable to find a single place in the IRP text in which I&M informs the reader that the resource modeling showed that there are cheaper alternatives to the portfolio I&M selected as the preferred portfolio.

Table 22 and Figure 33 of the IRP both show that in 4 of 5 scenarios, the Fleet Modification case has a lower PVRR than I&M's preferred portfolio. *See* I&M IRP at pp. 120, 126. The Fleet Modification case retires Rockport Unit 2 in 2022. While the IRP Rule does not require I&M to select the least-cost option as the preferred portfolio, the Rule does require I&M to clearly and transparently communicate to the public the results of the PVRR rankings. By neglecting to mention that I&M's preferred portfolio is not the least-cost option, and that the portfolio in which Rockport Unit 2 is retired is a cheaper option, I&M violated the requirements of 170 IAC 4-7-8(b)(7)(D).

Moreover, I&M does not provide a coherent and transparent rationale for selecting the Preferred Portfolio over lower-cost portfolios. I&M provides three basic explanations for selecting the Preferred Portfolio over other portfolios. First, I&M states that, "[a]s can be seen in Table 22, the Preferred Portfolio, under all but one pricing scenario, is less than one dollar/month (levelized basis) more expensive than the lowest cost portfolio for that scenario." I&M IRP at 119. But I&M fails to offer a single explanation about why customers should pay for a portfolio that is more expensive, even if it is only one or two dollars a month more expensive that alternative portfolios.

After picking the Preferred Portfolio because it is allegedly only slightly more expensive than other portfolios, I&M states that the Preferred portfolio "offers I&M significant flexibility should future conditions differ considerably from assumptions." *Id.* at 120. This explanation is not coherent and also misleading. The principal difference between the Preferred Portfolio and the Fleet Modification portfolio is that the Preferred Portfolio retains Rockport Unit 2 while the Fleet Modification portfolio retires Rockport Unit 2 in 2022. I&M purports to select the

Preferred Portfolio because it provides flexibility regarding implementation of energy efficiency programs and the ability to respond to "changing market conditions for resources such as renewables." *Id.* But it is unclear why I&M has any greater flexibility regarding energy efficiency implementation by virtue of retaining Rockport 2 versus retiring it. This statement is also misleading because it locks ratepayers into operating the Rockport unit for another 20 to 30 years. The Rockport facility faces massive environmental compliance costs of more than $[redacted], which would likely be repaid over 20-30 years. Locking customers in to paying back billions of dollars in capital upgrades on an aging unit is the opposite of a flexible plan.

I&M's third explanation for selecting the Preferred Portfolio is, essentially, that it simply saw no reason not to pick the plan. After presenting the results of the stochastic modeling, I&M states that "[b]ased on the risk modeling performed, it is reasonable to conclude that the inherent risk characteristics of all the portfolios are comparable and that no one portfolio is significantly advantaged. This indicates that the Preferred Portfolio represents a reasonable combination of expected costs and risk relative to the cost-risk profile of the portfolios that exclude one or both Rockport units." I&M IRP at 126. In other words, after being faced with stochastic modeling results that allegedly showed no significant difference between plans, I&M arbitrarily decided to go with its Preferred Plan. In addition to being essentially arbitrary, I&M's decision once again ignores that the Preferred Portfolio would cost more than the Fleet Modification portfolio that retires Rockport 2 in 2022. I&M IRP at 126, Figure 33.

While I&M has discretion under the IRP Rule to select a portfolio that is not least-cost, I&M needs to provide a transparent, and logical, explanation as to why it selected one portfolio over others. Here, I&M did not provide a coherent rationale that comports with the data presented in the IRP.

C. Requirement: Analyze how existing facilities will conform to a plan to comply with existing and reasonably expected state and federal environmental regulations.

Duke

1. Duke Should Have Provided Estimates in the IRP of the Cost to Comply with Environmental Regulations.

Duke's IRP acknowledges that it will have to incur capital and operating and maintenance costs to comply with several new, federal environmental rules that apply to its coal units. While Duke provides a qualitative description of the kinds of capital projects necessary to comply with various environmental rules, *see* Duke IRP at 123-24, Duke does not provide cost estimates of such projects. *See id.*, 125-26. Although Duke did provide this information in response to informal discovery requests, this creates an extra burden on the public to obtain critical information that the utility should simply include in the confidential version of the IRP.

The IRP Rule requires each IRP to analyze how the resources that survive the initial screening analysis will conform to a plan to comply with existing and reasonably expected environmental regulations. 170 IAC 4-7-7(a)(2). Depending on the capital upgrades needed for a particular rule, environmental compliance costs can run into the tens to hundreds of millions of dollars or more. Environmental compliance costs can be large enough to render a unit uneconomic; environmental compliance costs can mean the difference between retiring or retaining an existing unit. Given the importance of environmental compliance costs to any resource analysis, Duke should provide the total compliance cost for each unit/plant for each rule and the assumed compliance date for each rule in the IRP itself.

We recognize that Duke considers its environmental compliance costs as confidential, but Duke should simply include such information in the unredacted version of the IRP. When the information is not included in the IRP itself, the public has to submit informal discovery requests, which takes longer than to simply receive a copy of the unredacted version of the IRP. Expediting the public's access to critical information is important, given the limited time between submission of the IRP and the comment deadline.

I&M

1. I&M Would Have to Spend More than $[redacted] to Operate the Rockport Plant in Compliance with Federal Environmental Standards.

In contrast to Duke, I&M provided information in both the IRP itself and in informal discovery regarding the technologies, including capital cost estimates, necessary for future compliance with federal environmental rules. I&M would have to spend more than $[redacted] to ensure its Rockport plant complies with current environmental rules. This estimate only reflects the capital costs and does not include the increased fixed and variable O&M costs to operate the environmental controls. These omitted variable costs could be significant expenses. For instance, sorbents needed to operate Rockport's dry sorbent injection ("DSI") system to comply with the Mercury and Air Toxics, (MATS) rule and Consent Decree are likely to far exceed the capital costs associated with this control technology. Failing to include these variable costs thus significantly underestimates compliance costs for these facilities. The table below reproduces information on the expected environmental compliance costs for Rockport Units 1 and 2:

Expected Environmental Capital Costs for Rockport Units 1 and 2[21]

Rule Requirement	**Rockport 1**	**Rockport 2**	**Rockport 1 & 2**
Consent Decree, FGD	[redacted]	[redacted]	[redacted]
Consent Decree, SCR			
ELG Rule[22]			
CCR Rule[23]			
316(b) Rule			
TOTAL			

Before investing billions of dollars to bring the Rockport units into compliance with environmental standards, it is critical that I&M evaluate whether it retirement of one or both of the Rockport units is more economic and/or less risky than maintaining this generation.

[21] Spreadsheet "CONFIDENTIAL WP_Table 2_ Capital Cost Alternative Summary (R2-032714)," Tab "Calc_CF Mjr Env Capex w&wo OH." The costs listed appear in cells W168-181, and are the updated costs with overhead.

[22] We assume that the "Dry Bottom Ash Conversion" capital projects are to comply with the zero-discharge limit on bottom ash wastewater in the ELG Rule.

[23] We assume that the "Bottom Ash Pond Re-line" and "Landfill (adj)" projects are to comply with the CCR Rule, and have summed those costs to calculate CCR compliance costs.

D. Requirement: Energy and Demand Forecasts (170 IAC 4-7-5)

Duke

1. Duke's Forecast of Sustained, Significant Growth in Peak Load and Energy Sales Likely Overestimates Future Demand, Skewing the Entire Resource Analysis.

After the recession that began in 2008, utilities around the country saw steep drops in energy sales and peak load. Duke was no exception to this trend. *See* IRP at 205-06. While the economy has recovered, national economic growth has been modest, and is expected to remain so for many years. *See* I&M IRP at 7. Equally important, various trends, including improved energy efficiency standards, have led to a "long-run trend of slowing growth in electricity use relative to economic growth," a trend which "will also continue."[24]

I&M's forecast is consistent with these broader national trends. I&M forecasts very little growth in energy sales and peak demand. I&M IRP at 7. By contrast, Duke forecasts significant growth in both energy sales and peak demand. Duke IRP at 43-44. Given the large gap between the energy and demand growth that Duke is projecting versus what other utilities are projecting, there is reason to believe that Duke's forecast may prove overly optimistic.

It would be helpful to know the precision of Duke's prior forecasts compared to actual peak demand, but it is difficult to evaluate Duke's track record. Duke's IRP indicates that over the preceding 10 years, Duke's forecasted peak demand has consistently been higher than actual peak demand. In particular, Duke's forecasted summer peak demand exceeded actual peak demand in 8 out of 10 years, while forecasted peak winter demand exceeded actual peak demand in 9 out of 10 years. *See* Duke IRP at 206.

However, Duke provides only a comparison between forecasted peak demand before demand response and actual peak demand after demand response. Because the presence of demand response does not mean it was actually called upon at the time of peak demand, this makes it impossible to tell from the IRP itself whether the difference between forecasted and actual peak demand is attributable to demand response, to flaws in Duke's forecasting methodology, or a combination of the two. The Commission should request that Duke provide it with this information, so that Commission's Comments on the Draft Report can show a comparison between forecasted and actual peak demand in a way that compares apples to apples, e.g., that compares forecasted and actual peak demand where both are stated before, or after, demand response or that tells the reader how much actual demand response occurred in each year.

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[24] United States Energy Information Administration, U.S. ECONOMY AND ELECTRICITY DEMAND GROWTH ARE LINKED, BUT RELATIONSHIP IS CHANGING (Mar. 22, 2013), *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=10491.

To the extent that Duke has overestimated peak load and energy sales, this would affect the entire IRP. The load forecast sets the levels of peak demand and energy sales that the model solves for; the purpose of the modeling is to select an optimal portfolio to meet peak demand energy sales, subject to cost considerations and various other constraints. Duke's IRP likely overestimates both peak load and energy sales, which then leads the model to add more resources than would be necessary under lower load and energy sales.

E. IRP Stakeholder Process

1. I&M Stakeholder Process Prior to IRP Submission

We are pleased that I&M provided four opportunities for interaction with stakeholders last year, including three in-person meetings and one by telephone. I&M did a good job in providing meeting materials at least a week in advance of each meeting. Additionally, we appreciate I&M's willingness to respond to stakeholder requests to develop specific portfolios. However, there are certain aspects of the stakeholder process that we believe I&M can improve upon going forward.

First, while the number of meetings was sufficient, their locations were problematic. Two of the in-person meetings were held in Indianapolis, far from I&M's service territory. This made it difficult for I&M customers to participate in the process. This is evidenced by the fact that the greatest I&M customer participation occurred at the South Bend meeting. As I&M staff noted in an email to stakeholders, "Meetings in I&M's service territory will provide a broader opportunity for I&M customers and stakeholders who have an interest in the IRP process to attend." We believe a majority of meetings should be held in I&M's service territory because I&M customers are the ones most affected by IRP decisions.

Second, I&M can make certain technological improvements to increase accessibility for remote attendees. This group of attendees had to participate over a telephone line, which made it difficult for them to follow along with the presentation. It was impossible for listeners to know what slide the speaker was on unless the speaker was careful to note each slide in advance. In order to facilitate participation by those not in the room, we suggest I&M implement a program like "GoToMeeting" to enable remote access of the slideshow. I&M should also consider bringing in an outside facilitator to design the meetings and maximize stakeholder participation.

Lastly, I&M can improve upon their meeting documentation process. I&M failed to prepare and circulate meeting minutes. This failure was a direct violation of a draft rule stating that I&M would "develop and publish meeting minutes within 15 (fifteen) days following each meeting." [cite] Instead of complying with this rule, I&M asked stakeholders to email them with any questions we asked during the meeting. This is an insufficient procedure for meeting documentation and I&M should be more diligent about creating meeting minutes.

2. Duke Stakeholder Process Prior to IRP Submission

The undersigned individuals and organizations appreciated the opportunity to participate in Duke's IRP process in 2015. We The Commenters are generally pleased with Duke's stakeholder process this past year. We appreciated the fact that Duke Energy's staff was willing to spend time outside the meetings answering questions from stakeholders and exploring issues with them. We also believe the meetings were properly located to achieve stakeholder participation. Hosting meetings in Plainfield provided a central location for Duke customers and the IURC and OUCC staff to attend. Lastly, we appreciated the involvement of an outside facilitator. The facilitator helped design a process that developed creative ways to seek customer input into preferred future portfolios and risk analysis. That being said, there are still a few areas where Duke can improve.

Stakeholders struggled when trying to access the site of Duke stakeholder meetings. Instructions about parking and signage directing people to the right parking lot at meetings could have been clearer. Additionally, participants experienced a number of technical difficulties. Remote attendees were prevented from participating in one meeting due to technological difficulties. On occasion, participants were also barred from accessing the internet. Clearing up these minor shortcomings will greatly improve the efficiency of Duke's stakeholder meetings.

3. I&M and Duke Stakeholder Processes after the Submission of IRPs

I&M's IRP modeling team deserves high praise for their transparency and their helpfulness. We had five conference calls with various members of their team and also communicated by email for follow-up questions. The IRP modeling team was very easy to contact, quick to answer questions (often responding to emails in less than 24 hours), and generally provided the information we requested without issue. Particularly if Indiana decides to continue with a very compressed timeframe for IRP review (3 months rather than 4 months, especially with that timeframe falling over two major holidays), we hope the I&M IRP modeling team will serve a model for best practice communication between stakeholders and utilities.

The issues we did encounter during our review arose because of data reporting limitations within Plexos and a lack of cooperation on the part of the Plexos vendor, Energy Exemplar. Plexos is not set up to provide input data in an easy to understand format; and some data that is normally contained in outputs from other models was missing from I&M's initial submission to us. From our perspective, I&M worked hard to rectify these issues and got us all the output data we requested. But it was not possible to resolve all the issues that arose because of roadblocks on Energy Exemplar's part.

After our initial request for input and output files, we were told that the inputs were only available in a file that would effectively not be understandable. One option, offered by Energy Exemplar, was to buy a read-only Plexos license to view the data, but our clients felt strongly that doing so would indicate that transparency in an IRP could only be had at a price, creating a dangerous precedent for future Indiana IRPs. I&M was able to extract some input data by rerunning the model and provided that data on January 26, 2016. When it became clear during a call on January 29, 2016, that the data only pertained to the Steady State portfolio, we asked I&M to send us their input file in lieu of rerunning each portfolio. The input data is contained in a file that is not easily readable as it is akin to reading a website by looking at its html code. Even so, we thought we might be able to see some of the new resource build constraints that were imposed on the modeling in other plans. When I&M delivered this file on February 3, 2016, however, they said Energy Exemplar only consented to sharing it so long as it was treated as confidential and did not become part of the IRP "proceeding." We felt the latter condition essentially rendered the file useless since no one else who was a party to this filing would be able to see it, and Energy Exemplar presented no opportunity for stakeholders to sign nondisclosure agreements to view the information.

Energy Exemplar also refused to provide us with the documents that constitute the manual for Plexos. When reviewing modeling files, we often find that it is helpful to have the modeling software manual on hand for reference. Input data does not consist merely of the data put into the model such as load forecast, fuel prices, etc., but also what might be called the "settings." These "settings" signal to the modeling software how data items should be treated. Sometimes it is as simple as indicating whether load is in kWh or MWh, and sometimes it is much more complex like indicating how the model should interpret bid prices for the purposes of simulating dispatch. Other times, the settings are somewhere in the middle, like telling the model when new resources are available and in what quantity. The manual, in conjunction with readable input data, is essential to having a full picture of how the modeler arrived at the modeling results.

We believe I&M's IRP modeling team understands our perspective in this regard and has indicated that they are trying to move Energy Exemplar towards a greater level of transparency, particularly because of the public stakeholder process contemplated within the IRP rule. But we will continue to have concerns about the use of Plexos for IRP modeling so long as the manual and the full set of input data cannot be provided in an understandable format.

In contrast to I&M, we had much more difficulty getting information from Duke. Their IRP modeling team was quick to schedule an initial conference call at our request, but the personnel able to answer those questions were not on the phone, even though we advised that we wanted to discuss the development of their energy efficiency "bundles" for modeling. A follow-up call on this topic could not be scheduled until a week later and then was cancelled by Duke two days before.

In the same way that we communicated with I&M's team, we sent email requests to Duke's team. However, all requests were interpreted as new informal discovery and generally subject to a 10-day turnaround, although we appreciate Duke's effort to get many responses in a more expeditious timeframe. This included simple questions such as clarifying what units data were in, as well as pointing out that data we had already requested was missing from prior responses.

For example, we made our first informal discovery request to Duke on November 23, 2015 and then clarified that request on December 7, 2015 at Duke's request. Initially, Duke committed to providing the responsive material on December 18, 2015, but did not deliver those materials until January 4, 2016. Although there was delay on our end because of the nondisclosure agreement, we anticipated still receiving at least the public data and responses on December 18, 2015. As we reviewed these materials, we realized on January 19, 2016, that Duke had not provided the System Optimizer input files which should have been with the modeling files provided on January 4, 2016, and notified them as such. The files were not delivered to CAC offices until January 27, 2016.

Even if all modeling files had been delivered on January 4, 2016, it would have been impossible for us to review all the runs conducted in depth – there was simply not enough time to do so. This is one of the reasons that we would encourage the utilities to provide the Commission and stakeholders with all inputs with the submission of the utility's IRP and that the Commission extend the period of time available to review data and draft comments to four months. Particularly when more than one IRP must be reviewed, the current timeframe limits what is feasible to review.

Our review of Duke's IRP did go more smoothly in one way. Data reporting out of Duke's IRP models is superior to that of Plexos. Between the input and output files, once they were all provided, the data that we normally review in IRP proceedings appeared to be present.

Finally, our experience working on these IRPs underscores the importance of having a discovery process of some kind. Whether formal or informal, using solely the information in an IRP is very unlikely to facilitate the kind of review contained in these comments. Although Duke made our requests for information and for clarifications into informal data requests, it still left us in a situation where we were at the behest of the utility and had to constantly be asking for more information and more clarifications, which was particularly difficult over the holidays. While we prefer the approach taken by I&M, we understand it's difficult to dictate a cooperative process. For those instances where a utility prefers discovery more similar to that in docketed cases, we ask that enough time be provided to ask several rounds of discovery in order to do a thorough review of the responses.

Respectfully submitted,

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