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COMMENTS OF CITIZENS ACTION COALITION OF INDIANA, INC., EARTHJUSTICE, MULLETT & ASSOCIATES AND SIERRA CLUB ON THE IURC ELECTRICITY DIVISION DIRECTOR'S DRAFT REPORT REGARDING 2013 INTEGRATED RESOURCE PLANS

Pursuant to the Indiana Utility Regulatory Commission's ("IURC" or "Commission") Electric Utility Integrated Resource Planning Rule, 170 IAC 4-7,[1] Citizens Action Coalition of Indiana, Inc. ("CAC"), Earthjustice, Mullett & Associates and Sierra Club (collectively, "Commenters") hereby submit the following comments in response to the Draft Report of the Commission's Electricity Division Director Regarding 2013 Integrated Resource Plans ("Draft Report"), which Dr. Borum issued on February 28, 2014. Commenters submitted timely comments on the 2013 IRPs of Indiana Michigan Power ("I&M") and Duke Energy Indiana ("DEI") on January 30, 2014 and February 7, 2014, respectively,[2] and focus here on the Draft Report as it relates to the IRPs of I&M and DEI. Commenters also briefly raise issues relevant to the Legislature's recent enactment of SEA 340.

I. The IRP Public Advisory Process Should be Improved.

I&M and DEI both held IRP stakeholder processes pursuant to 170 IAC 4-7-2.1. While these processes represent a good first step, substantial improvements are needed to strengthen the advisory process going forward. One of the key areas of improvement is meeting accessibility. As discussed in the I&M IRP Comments, a majority of the meetings should be held at readily accessible locations in the utility's service territory to make it easier for stakeholders to attend in person. (CAC et al.'s I&M Comments at 4.) Additionally, utilities should provide an option for remote participation via webinars or teleconference. (CAC et al.'s I&M Comments at 4.) We

[1] Unless otherwise noted, 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.

[2] CAC, Earthjustice, and Sierra Club submitted comments on the I&M IRP. These three groups plus Mullett & Associates submitted comments on DEI's IRP, which were prepared by Synapse Energy Economics and Schlissel Technical Consulting.

therefore agree with the Draft Report's conclusion that stakeholder meetings should be located in the utility's service territory, whenever possible, and webinars and other tools should be used to make meetings accessible to interested parties who cannot attend in person. (Draft Report at 30.) These improvements will result in increased participation and an improved process overall.

Additional enhancements to create a more robust process include holding at least 4-5 meetings of sufficient length to allow for a "deep dive" into the various components of integrated resource planning, including modeling, scenario analyses and underlying assumptions, and information flow. (CAC et al.'s I&M Comments at 4.) Utilities should also distribute meeting materials at least one to two weeks in advance of a given meeting so that stakeholders can more meaningfully participate in the meetings. (*Id.* at 4.) A stakeholder listserv would facilitate this distribution.

Meaningful stakeholder participation depends in large part on utility receptivity to feedback and requests for information. As discussed in the Draft Report, utilities should anticipate "non-agenda questions" and commit to providing a response to stakeholder inquiries at the meeting or through timely follow up. (Draft Report at 30.) Utilities should ensure that stakeholders have sufficient time to provide feedback on the development of the IRP, particularly modeling, and should provide detailed explanations in writing when stakeholder suggestions are not selected. (CAC et al.'s I&M Comments at 5.) The Final Report should incorporate these suggestions in an effort to improve the stakeholder process going forward.

Finally, the stakeholder process and outcome could also be improved by having more robust tools to track and incorporate comments and suggestions regarding scenarios, modeling data and underlying assumptions, and portfolios. During the I&M stakeholder process, comments from one meeting often did not carry over to subsequent meetings and/or were not responded to or reflected in the modeling. As a result, stakeholders did not have time or opportunity to engage with I&M concerning its responses to those comments as they arose in the stakeholder process and to develop more thorough modeling scenarios based on those exchanges. In the DEI stakeholder process, DEI did provide written responses to some of the comments raised by stakeholders during the process, but the responses were often superficial and did not lead to meaningful dialogue concerning DEI's modeling assumptions or evaluation of alternative resource portfolios.

II. The Companies Fail to Identify, and Quantify Where Possible, A Number of Additional Costs and Risks Facing Their Preferred Resource Portfolios.

A core requirement of the Commission's proposed IRP rule is that Indiana's utilities should attempt to identify and quantify to the extent feasible the risks and uncertainties facing different alternative resource plans and, in selecting a preferred resource portfolio, "balance[] cost minimization with cost-effective risk and uncertainty reduction." 170 IAC 4-7-8(b)(7). According to the official summary of the Commission's 2012 Contemporary Issues Technical Conference, "[t]he revisions in the IRP rule are intended to stress that risk as well as cost should be considered when identifying future resources. The goal is to move from simply identifying the 'least cost' plan to a more robust plan that holds up to future risks and represents the best combination of cost and risk. . . . Commission staff hopes for discussion in the IRP regarding what went into [the] decision-making process and how the utility weighed the uncertainties."[3]

As the Draft Report recognizes, both the DEI and I&M IRP filings' analyses of the costs and risks of its preferred resource portfolio and its comparison of its preferred portfolio with alternatives fail to live up to the requirements of the Commission's proposed IRP rule, in

[3] Summary of IRP Contemporary Issues Technical Conference, at 2-4 (Oct. 18, 2012), at http://www.in.gov/iurc/files/Summary_of_IRP_Contemporary_Issues_Technical_Conference_held_on_Oct_18_2012.pdf.

particular 170 IAC 4-7-8(b)(7). With respect to both the DEI and I&M IRP filings, the Draft Report notes that:

> "[t]here is little mention of the value of flexibility in the resource plan. In reality, one would expect the utility to change course with their resource plan if they discovered that the world was not turning out like they originally thought it would."

(Draft Report at 6, 15.) As Commenters pointed out in their comments on both the DEI and I&M IRPs, there are numerous costs, risks, and uncertainties facing the coal-fired generating units in both DEI's and I&M's portfolios. The companies' failure to identify, and quantify where possible, those costs, risks, and uncertainties unduly biases their modeling in favor of investments in coal-fired generation that may not be prudent and fails to recognize the need for flexibility that Commission Staff recognize in the Draft Report. Commission Staff should call on the companies to correct the informational, methodological, and procedural deficiencies in their IRP filings that Commenters identified in their original comments on each filing.

In addition, missing from the risk assessments in the plans is any discussion of the possible impacts of changes in historic water flow patterns over the next twenty years due to climate change. These could be both increased occurrences of flooding, which could threaten riverside coal ash impoundments, and increased frequency of extreme drought, which would affect power plant cooling systems both in water availability and discharge temperature requirements. Duke Energy Indiana is particularly exposed to these risks because of its power plants on the Wabash and White rivers.

A. Duke Energy Indiana

Commenters echo the concerns raised by Commission Staff in the Draft Report concerning DEI's analysis of portfolios and use of scenarios. As the Draft Report notes, DEI appears to have placed artificial constraints on its analysis of the economics of retrofitting its existing coal-fired generating units as opposed to retiring them by "hard-wiring" its decisions with respect to each unit prior to running the System Optimizer model. (Draft Report at 13.) Although DEI's use of three separate portfolios with different assumptions concerning fuel prices and the stringency of environmental regulations is an improvement over the Company's prior resource planning efforts (*see* Draft Report at 14-15), DEI's failure to evaluate additional scenarios limits the utility of its analysis, because

> "it is impossible to tell which factors contribute to the increased observed retirements. Is the choice to retire more units sensitive to coal prices, energy prices, or carbon prices? And to what degree?"

(CAC et al.'s Duke Comments at 20.) As the Draft Report notes, "[w]hile [DEI's] approach is useful for comparing the three specific portfolios, it can give a false sense that a particular portfolio is 'best' across a wide range of scenarios. There could be a fourth portfolio that is not optimal under any of the three defined scenarios but is better than any of the others across a wide range of the intermediate combinations of scenarios." (Draft Report at 14.)

Commenters' comments on the DEI IRP identify additional costs, risks, and uncertainties facing DEI's coal-fired generating fleet that the Company should evaluate more rigorously in any future resource planning. First, DEI has not updated its assumptions concerning future carbon prices since its 2011 IRP filing, despite the fact that in 2013, President Obama issued an executive order directing the U.S. Environmental Protection Agency to complete work on Clean

Air Act greenhouse gas regulations for existing power plants by 2015. (CAC et al.'s Duke Comments at 2.) DEI does not adequately explain or justify its carbon price assumptions in this IRP, in particular why its assumed carbon prices are significantly lower than the Synapse price forecast and why even its high carbon price projection (included in the "Environmental Focus" scenario in this IRP) is far lower than the U.S. Government's estimate of the "social cost of carbon." (CAC et al.'s Duke Comments at 3.) Commission Staff should direct DEI to evaluate higher carbon prices in their base case and alternative scenarios in any future resource planning. (CAC et al.'s Duke Comments at 4.)

Second, Commenters identified the following questions and issues facing specific DEI coal-fired generating units:

- Under DEI's own IRP inputs, Gallagher Units 2 and 4 appear to be losing money for ratepayers today, even before accounting for projected environmental capital costs facing the units between now and 2019. (CAC et al.'s Duke Comments at 4-7.) The DEI IRP does not acknowledge this or evaluate whether retirement of the Gallagher units in the near term would benefit ratepayers.
- The future economic viability of Gibson Unit 5 appears tenuous, with the future cost of coal and the risk of more stringent environmental regulations being the primary determinants in whether retiring the unit is in the best interest of ratepayers. (CAC et al.'s Duke Comments at 7-9.) The DEI IRP fails to evaluate the risks and uncertainties facing the unit from the possibility of higher coal prices than it assumes in its modeling or that more stringent environmental regulations might require an earlier date for installation of a Flue Gas Desulfurization system, either or both of which could result in a planned

retirement of Gibson Unit 5 benefitting ratepayers. (CAC et al.'s Duke Comments at 7-9.)

- DEI's 2013 IRP appears to assume that the costs of installing Selective Catalytic Reduction systems at the Cayuga Station have already been incurred, despite the fact that construction is still underway and over half of the costs are still avoidable. (CAC et al.'s Duke Comments at 10.) Like Gibson Unit 5, the future economic viability of the two Cayuga units appears vulnerable to future movements in coal prices and environmental regulations (in particular regulation of greenhouse gases). (CAC et al.'s Duke Comments at 10-12.)
- DEI's 2013 IRP grossly over-estimates the availability and operating performance / net generation of the Edwardsport IGCC plant, when compared both to Edwardsport's own operating history to date and that of other IGCC plants. (CAC et al.'s Duke Comments at 12-14.) The Company should be required to evaluate scenarios in which it assumes that Edwardsport has a lower availability and/or higher operating costs than it assumed in its IRP modeling. (CAC et al.'s Duke Comments at 14-15.)

Any range of scenarios evaluated by DEI in its future resource planning should evaluate the full range of costs, risks, and uncertainties identified by Commenters as facing DEI's coal-fired generating fleet.

B. Indiana Michigan Power

The Commission Staff correctly points out that I&M's preferred resource portfolio and other resource portfolios in which the Company continues to rely on generation from its two coal-fired units at the Rockport plant "exhibited higher risk than the stakeholder portfolios that diversified by using natural gas, nuclear, renewables, or demand-side measures." (Draft Report at 5.) Commenters made a similar point in their comments on I&M's IRP filing. (CAC et al.'s I&M Comments at 21.) Conversely, I&M's alternative resource portfolios that add greater energy efficiency and renewable capacity have less revenue requirement at risk than the Company's preferred approach. (Draft Report at 5; CAC et al.'s I&M Comments at 21.) Nevertheless, the Company asserts in the IRP that the higher risk of its preferred plan is acceptable given that the Company finds that its preferred plan has a lower cost and that it represents a "reasonable combination of expected costs and risk relative to the cost-risk profiles of the other portfolios." (CAC et al.'s I&M Comments at 21.)

One of the major factors driving risk to I&M's preferred resource portfolio is the likely imminent establishment of greenhouse gas emissions regulations, which have the potential to significantly impact the economics of coal-fired generation. Commission Staff recognizes this in the Draft Report, noting that I&M "may reconsider [its] plans regarding Rockport if significant carbon restrictions were put in place." (Draft Report at 6.) I&M assumed in its IRP, however, that any carbon regulations ultimately adopted would not have costs "so onerous that [they] "shut[] in" a significant portion of the nation's generation fleet," including the Rockport plant. (CAC et al.'s I&M Comments at 23.) This assumption severely limits the robustness of I&M's analysis by failing to evaluate the alternative resource portfolios considered by I&M (and the risks and uncertainties inherent in each) against a range of potential futures. (CAC et al.'s I&M Comments at 22-24.) I&M's result-driven approach to analyzing the possible future costs and risks of GHG regulation disregards predictions by the federal government, the research community, public utility commissions, and other utilities engaged in recent IRP processes that contemplate a range of possible future carbon prices, some of which would be significantly greater than the single $15/metric ton carbon price that I&M used to evaluate alternative resource portfolios. (CAC et al.'s I&M Comments at 25-29.) I&M also assumes that any carbon price will not take effect until at least 2022, notwithstanding that EPA regulations on greenhouse gas emissions at existing power plants could be finalized as early as 2015. (CAC et al.'s I&M Comments at 29.) In a separate comment on I&M's IRP filing, Wind on the Wires ("WoW") similarly notes that I&M's carbon price assumptions are "low in comparison to other models," and thus that I&M should evaluate a higher range of possible carbon costs. (WoW I&M Comments at 5.)[4]

In addition, as Commenters pointed out in their original comments on I&M's IRP filing, I&M's comparison of the relative cost-risk profiles of different portfolios is not valid, because I&M fails to account for a number of additional future costs and risks facing coal-fired generating units and/or is impossible to evaluate because it fails to explain its assumptions concerning those costs and risks. First, I&M fails to evaluate the risk that by failing to evaluate and implement increased levels of DSM and renewable energy, the prudency of its planned investments in coal-fired generation can be called into question. (CAC et al.'s I&M Comments at 15.) Second, with respect to the Rockport Power Plant, I&M has failed to fully identify, reasonably quantify and account for the risks that the Rockport units will face greater costs, or face costs earlier in the planning period, from regulations of greenhouse gases, air quality, wastewater, and coal ash, as well as the risks to the Rockport units from natural gas prices and capacity prices that will be lower than the high projections that I&M is assuming in its modeling. (CAC et al.'s I&M Comments at 22-40.) Third, I&M's preferred portfolio continues to rely on purchases of power from two other coal-fired power plants, the Ohio Valley Electric

[4] Commenters further agree with Wind on the Wires that I&M did not transparently account for the costs of U.S. EPA's forthcoming Coal Combustion Residuals Rule in its IRP modeling. (*See* WoW I&M Comments at 5; CAC et al.'s I&M Comments at 32-34.)

Corporation's Clifty Creek and Kyger Creek plants (of which I&M is a partial owner), but I&M's IRP filing contains absolutely *no* discussion of the future costs or risks facing those plants, and in particular *no* discussion of any future environmental compliance costs at those plants. (CAC et al.'s I&M Comments at 40-42.)

In light of the numerous costs, risks, and uncertainties that Commenters have documented for I&M's IRP filing, Commenters share Commission Staff's view in the Draft Report that

> "[p]referably, I&M would have first developed a range of scenarios based on distinctive possible futures. Then an optimal resource plan would have been developed for each scenario, and each of these plans would have been subjected to stress testing such as that performed using Monte Carlo analysis. I&M instead really only had two scenarios for which optimal resource plans were developed, and the only difference between the two scenarios was the load forecast. It is a stretch to consider these distinctly different scenarios."

(Draft Report at 6.) Any range of scenarios evaluated by I&M in its future resource planning should evaluate the full range of costs, risks, and uncertainties identified by Commenters with I&M's preferred resource portfolio.

III. The Utilities Fail to Adequately Evaluate Energy Efficiency and Underestimate the Potential for Increased Savings.

This Commission has long recognized that "an important component of long-term planning for Indiana's generation needs is the effective utilization of DSM programs by jurisdictional utilities that have a duty to serve their ratepayers in a cost effective manner."[5] As such, a core requirement of an IRP is the demonstration that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis, and that the

[5] Phase II Order, p. 30, IURC Cause No. 42693 (Dec. 9, 2009).

utility's preferred resource portfolio utilizes, to the extent practical, all economical load management, demand side management, and energy efficiency improvements as sources of new supply. 170 IAC 4-7-8(b)(3), (4). Unfortunately, DEI and I&M's IRPs do not reflect adequate consideration (or utilization) of the energy efficiency resource and, as such, fail to meet the requirements set out in 170 IAC 4-7-8(b)(3), (4).

Since the Draft Report was issued, SEA 340 became law without the Governor's signature. SEA 340 terminates the State's existing energy efficiency program, known as Energizing Indiana, as of December 31, 2014. Along with a public statement explaining why he did not sign SEA 340, Governor Pence sent separate letters to the Commission Chairman and the Chamber and Utility Committee leaders in the State House and Senate (copies attached as Attachments 1 and 2, respectively) in which he directed the Commission to develop recommendations to inform a new legislative framework for an energy efficiency program for Indiana and requested legislative leaders to work with him to develop a new energy efficiency program to replace Energizing Indiana. However, any new framework or program developed would not go into effect prior to the expiration of Energizing Indiana on December 31, 2014. Moreover, although the Presidents of both DEI and I&M made public commitments during the debate on SEA 340 to continue their energy efficiency programs beyond 2014,[6] what these commitments mean in practice is unclear.

Although these recent developments have introduced alarm and confusion concerning the future of energy efficiency in Indiana, utilities' obligations with respect to considering and

[6] Chodak, Paul. "Continue on path of energy efficiency." The Star Press [Muncie]. 18 March 2014, available at: http://www.thestarpress.com/article/20140319/OPINION03/303190016/Continue-path-energy-efficiency?nclick_check=1 ("Our customers should rest assured that now and in the future, I&M will seek to help our customers use energy more efficiently.")
Esamann, Douglas. "Energy efficiency work will continue despite legislation." The Indianapolis Star. 21 March 2014, available at http://www.indystar.com/story/opinion/readers/2014/03/21/energy-efficiency-work-will-continue-despite-legislation/6690489/ ("We will continue to offer similar opportunities if Senate Bill 340 becomes law.")

integrating energy efficiency into their resource plans remains. Utilities must adhere to the requirements provided in the Commission's IRP rule.[7] For example, utilities must consider a demand-side resource as a source of new supply in meeting future electric service requirements and provide detailed information concerning utility-sponsored programs identified as potential demand-side resources. 170 IAC 4-7-6(b). 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)). Utilities must also show that their preferred resource portfolios utilize, to the extent practical, all economical load management, demand side management, and energy efficiency improvements, among other resources, as sources of new supply (170 IAC 4-7-8(b)(4)). That is, utilities must show that they have evaluated energy efficiency and other demand-side resources fairly and that they utilize all cost effective demand-side management resources available in their respective service territories. Such a demonstration is critical to utilities fulfilling their fundamental obligation to provide customers with "reasonably adequate service" at "just and reasonable rates" under Ind. Code 8-1-2-4 and making the necessary showing to justify new supply-side additions under Ind. Code 8-1-8.5-1 et seq.

A. Duke Energy Indiana

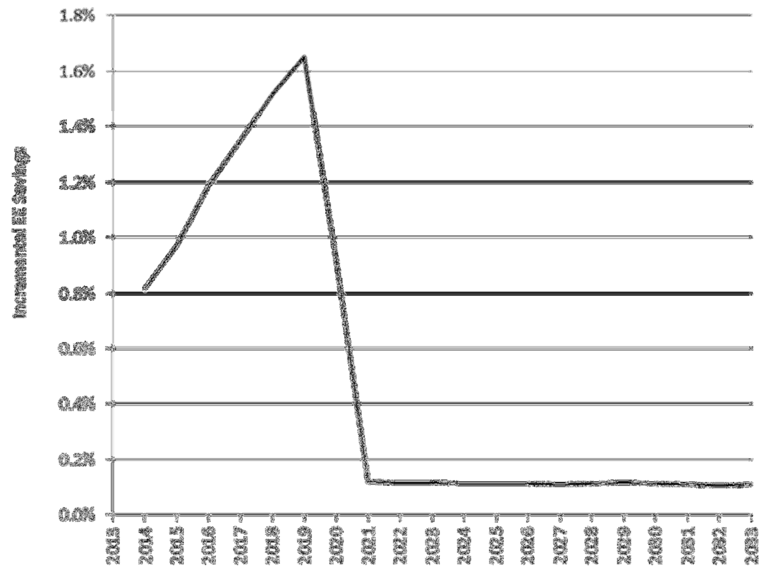
As the Draft Report recognizes, DEI did not optimize energy efficiency, or allow it to compete with its generation resources. (Draft Report at 15.) Rather, DEI "hard-wired" energy efficiency into the model for each year of the planning period. (*Id.*) Moreover, DEI failed to adequately explain how it derived the three different scenarios of efficiency impacts. (*Id.*) The

[7] On January 14, 2013, Governor Pence issued Executive Order 13-03, which put into place a rulemaking moratorium. The amendment to the IRP rule currently falls under the rulemaking moratorium; however, both DEI and I&M (as well as other utilities) have agreed to follow the Rule although it is still pending.

final report on the IRP should call on DEI to remedy these significant methodological and informational deficiencies. (*See* 170 IAC 4-7-2(h), (k).)

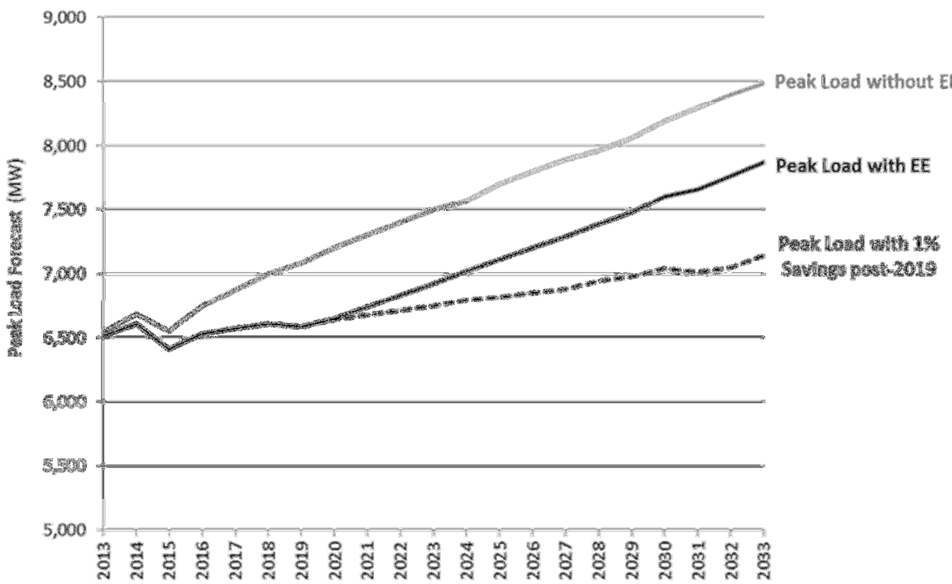
In its reference scenario, DEI assumed that it will comply with the then-existing energy savings goal by 2019 – a commitment that Commenters hope DEI will continue to meet, even with the enactment of SEA 340 – but then will effectively stop saving energy. As Figure 1 below shows, DEI projected that efficiency savings drop to a mere 0.1% per year after 2020, or about one sixteenth the rate it achieved in 2019.

Figure 1: DEI's incremental energy efficiency savings, by year.



Modeled this way, DEI essentially dropped energy efficiency out of its long-term plan to meet the resource needs of its customers. The result is a plan that must rely on more expensive supply-side generation to meet energy demand. As discussed in our comments on DEI's IRP, a conservative assumption of 1% incremental savings after 2019 would result in a significant decrease in peak load throughout the modeling period. (CAC et al.'s Duke Comments at 18-19.) Specifically, a 1% savings scenario after 2019 would result in an additional 733 MW in load reduction by the end of the planning period, as shown in Figure 2 below. Put differently, with a more reasonable energy efficiency assumption, DEI could save the rough equivalent of a new natural gas combined-cycle plant.

Figure 2. Peak load forecast for DEI, with DEI assumed EE, and Peak load savings at 1% incremental past 2019.



As detailed in our comments and reflected in the Draft Report, DEI's approach to modeling energy efficiency resources is flawed. Rather than letting efficiency compete with supply-side resources through an optimization process, the Company fixed an insufficient level of efficiency in its model. This substantial methodological flaw, in addition to the questions raised in the Draft Report concerning the incorporation of efficiency load impacts, should be reflected in the Commission's final report and addressed by the Company.

B. Indiana Michigan Power

Like DEI, I&M modeled energy efficiency impacts in the near term by adjusting its load forecast by a fixed amount of savings and did not allow efficiency to compete with supply-side resources on equal footing, directly violating 170 IAC 4-7-8(b)(4). Thus, I&M's short-term treatment of efficiency is similarly flawed. Unlike DEI, I&M appeared to fix a level of energy efficiency that would not meet the then-existing 2019 savings goal. I&M's projected noncompliance with the energy savings goal underscores the significance of its failure to optimize energy efficiency and demonstrate that its preferred portfolio utilizes, to the extent practical, "all economical ... demand side management ... and energy efficiency improvements as sources of new supply." 170 IAC 4-7- 8(b)(4).

I&M modeled additional energy efficiency beginning in 2020, the year after the total statewide savings goal was to be met. (IRP at 90,182.) However, I&M constructed two "optimized" cases that contain the same amount of DSM (249 MW). Thus, it does not appear that I&M evaluated any variation in energy efficiency levels in the long term either, here again calling into question the adequacy of and the intentions behind the Company's approach to evaluating the energy efficiency resource.

Further, the Company's efficiency analysis suffers from several informational deficiencies that "leaves a number of unanswered questions." (Draft Report at 7.) For example, although I&M states that noncompliance with regulatory mandates "has become I&M's view of a 'base' or expected outcome" (IRP at 30), I&M does not explain the "forecasted expected performance in Indiana" for energy efficiency programs, nor does it explain or demonstrate how this level was established. (Draft Report at 7.)

In the long term, the Company does not explain how it arrived at the selected amount of DSM (249 MW). I&M modeled additional efficiency starting in 2020 based on adjustments to third party cost estimates that are not sufficiently explained in the IRP. Specifically, I&M modeled additional energy efficiency resources based on cost assumptions it derived from Efficiency Vermont data, adjusting the data "to account for the difference in climate." (I&M IRP at 90.) I&M's measure costs appear high in comparison to estimates from other states.

(CAC et al.'s I&M Comments at 12.) Moreover, as the Draft Report and Commenters note, I&M does not specify or provide the exact information used, nor does it explain how it modified the data for use in Indiana. (Draft Report at 8; CAC et al.'s I&M Comments at 11-12.) I&M merely provides a hyperlink to a page on Efficiency Vermont's website that contains more than thirty documents, including annual reports and plans spanning back to 2003 through the present. (I&M IRP at 90.) The IRP does not contain a specific reference to a page or even a document. I&M's general reference to this third-party data source is insufficient to allow the Commission or the public to analyze *or even verify* the data. Thus, the Company fails to provide specific information required by 170 IAC 4-7-4(b)(2).

Finally, the Company's position that it cannot reach the prior savings goals due to the phasing in of federal lighting standards under the Energy Independence and Security Act of 2007 (EISA) is very troubling. (I&M IRP at 76-78.) Although increasing baselines will reduce energy savings attributable to utility programs, a substantial amount of energy savings from lighting has not yet been realized. As discussed in our comments, as baselines increase in lighting and other technologies, I&M should continue to explore emerging technologies and different marketing approaches for existing measures. (CAC et al.'s I&M Comments at 13-14.)

In sum, I&M's treatment of energy efficiency in its IRP raises numerous concerns that are unaddressed and amplified due to the Company's statements during the debate on SEA 340.[8]

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[8] Chodak, Paul. "Continue on path of energy efficiency." The Star Press [Muncie]. 18 March 2014, available at: http://www.thestarpress.com/article/20140319/OPINION03/303190016/Continue-path-energy-efficiency?nclick_check=1 ("By comparison, under current statewide energy efficiency programs, it costs I&M and its customers about 15 cents to save about 8 cents per kilowatt hour.")
Cf. 2012 Energizing Indiana EM&V Report, June 20, 2013, pp. 17, 25, available at: https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631801a1cc0 (finding that the Core program spent a total of $42.4 million in 2012 and achieved total gross savings of just over 339 million kWh). Applying the common industry formula for computing the levelized cost of kWh saved over the lifetime of measures, the Core program achieved electricity savings at a cost of approximately 1.6 – 2 cents per kWh, depending upon what assumption one makes about average life of measure.

"In the end, the reader of I&M's IRP has little understanding of the levels of energy efficiency included in the resource plan, how these levels were derived, and the data on which the energy efficiency analysis was based." (Draft Report at 7-8.) The Final Report should call on the Company to correct these significant informational and methodological errors.

IV. The Utilities' Analyses of Distributed Solar Generation is Flawed and Insufficient.

IRPs must include a discussion of distributed generation and the potential effects on generation, transmission, and distribution planning and load forecasting. Rule 170 IAC 4-7-4(b)(5). The IRPs, however, fall short.

I&M's illustration of the value of distributed generation (represented by solar PV) to the utility is flawed because, among other reasons, "the reader has no means to understand what I&M did." (Draft Report at 9.) I&M fails to provide any underlying data, inputs or assumptions in the IRP or appendix that support its conclusion that customer-sited solar distributed generation is uneconomic.

Based solely on the sparse information presented in Figures 4E-3 and 8C-2, I&M appears to undervalue distributed solar generation. I&M does not provide a comprehensive analysis of the full value of the resource. I&M limits the value of solar to the energy and generation capacity that is avoided, overlooking several other critical benefits distributed solar generation provides. (CAC et al.'s I&M Comments at 16-17.) Moreover, without evaluating the underlying data, it is unclear whether the energy and generating capacity values presented are reasonable. Finally, I&M does not explain what constitutes "the full retail net metering rate" in the model, or why it modeled distributed generation in 10 MW blocks per year given its 2012 total distributed solar nameplate capacity was 0.137 MW. The Final Report should direct I&M to remedy these methodological and informational shortcomings.

DEI's consideration of DG resources is also inadequate. As the Draft Report recognizes, DEI does not indicate how, if at all, distributed, customer-owned generation is modeled or otherwise reflected in its load forecast. (Draft Report at 17.) DEI also does not discuss how the rapid evolution of the technology and significant decline in costs impacts utility load and planning. (*Id.*) Finally, DEI's assertion that its energy efficiency and renewable energy projections can represent distributed generation placeholders to the extent this resource is not reflected in its load forecast is not sufficiently justified. (*Id.*)

V. The IRPs Fail to Evaluate CHP and Distributed Wind, and the Evaluation of Utility-Scale Resources Raises Concerns.

Utilities must consider cogeneration and non-utility generation in meeting future electric service requirements, and must demonstrate that its preferred portfolio utilizes, to the extent practical, all economical renewable resources, cogeneration, and distributed generation, among other resources. I&M's cursory discussion and dismissal of cogeneration and distributed wind resources does not meet this IRP requirement and should be remedied. I&M did not evaluate CHP (or even discuss it more generally) in its IRP, nor did it evaluate small distributed wind generation facilities (residential and commercial). (CAC et al.'s I&M Comments at 18-19.) Further, I&M limited the amount of utility-scale solar and wind resources that its model could select to annual increments of no more than 50 MW and 100 MW, respectively. (CAC et al.'s I&M Comments at 18-19.) I&M should explain why it imposed this annual cap in its modeling, which constrained the level of solar and wind resources that could be selected.

As it did with energy efficiency, DEI includes renewable resources as a "hardwired" part of a lower risk portfolio, but does not actually examine these resources as competitive supply side options. (CAC et al.'s Duke Comments at 15.) In its projected build out of wind, for example, DEI's model appears to prevent wind resources from coming online before 2019. (*Id.*)

Moreover, DEI's cost assumptions for wind appear high, in excess of federal and industry assumptions. (*Id.* at 16-17.) Rather than restricting when wind can compete with other resources and fixing high-cost wind assumptions into the model, DEI should have comprehensively evaluated the wind resource on a comparable basis to other supply-side resources by, among other things, reviewing recent wind offers and examined opportunities increase its renewable energy portfolio. (*Id.* at 17.)

Respectfully submitted,

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CERTIFICATE OF SERVICE

Commenters certify that on March 31, 2014, a copy of the foregoing was submitted electronically to Dr. Borum, the Director of the Electricity Division of the Commission, and served via electronic mail on the following interested parties that submitted written comments:

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On Behalf of Hoosier Environmental Council

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Jennifer A. Washburn

Jennifer A. Washburn
Citizens Action Coalition of Indiana, Inc.

Attachment 1

STATE OF INDIANA
OFFICE OF THE GOVERNOR
State House, Second Floor
Indianapolis, Indiana 46204

Michael R. Pence
Governor

March 27, 2014

James D. Atterholt
Chairman
Indiana Utility Regulatory Commission
PNC Center
101 West Washington Street, Suite 1500 E
Indianapolis, IN 46204

Dear Chairman Atterholt:

As you are aware, SEA 340 became law without my signature. Under the law, the IURC is required to submit a status report on all energy efficiency programs to the regulatory flexibility committee. In addition to that status report, I request that the IURC complete a set of recommendations that can inform the development of a new legislative framework to be considered in the 2015 session of the Indiana General Assembly.

Managing the demand-side of our electricity industry through energy efficiency is an important part of our energy strategy. I speak often of the need for an 'all of the above' energy strategy, and I include energy efficiency in my definition of 'all of the above.'

Energy efficiency measures reduce demand for electricity, which reduces the need to build new generation facilities and avoids the costs associated with those new facilities. The State Utility Forecasting Group's 2013 Forecast estimates that Indiana will need to add 1,450 megawatts of generation resources in the near term and 3,600 megawatts in the longer term in order to meet forecasted demand. Demand-side management (DSM) can help reduce that gap and is a critical part of ensuring that our public utilities provide electricity at the lowest cost possible.

To produce policies that can reduce that gap, in addition to the status report required by SEA 340, I request that the recommendations:

1. Include appropriate energy efficiency goals for Indiana.
2. Reflect an examination of the overall effectiveness of current DSM programs in the state.
3. Reflect any and all issues that may improve current DSM programs.
4. Reflect a thorough benefit-cost analysis of the cost impact to ratepayers of possible DSM programs.
5. Allow for an opt-out whereby large electricity consumers can decide not to participate in a DSM program.

I request that the IURC work with all relevant stakeholders to assist our administration in formulating the most effective energy efficiency policy for Indiana. And I ask that the IURC complete its recommendations on or before the termination of the current program.

Thank you in advance for your prompt attention to this matter.

Sincerely,

Michael R. Pence
Governor of Indiana

Sincerely,

Michael R. Pence
Governor of Indiana

Attachment 2

STATE OF INDIANA
OFFICE OF THE GOVERNOR
State House, Second Floor
Indianapolis, Indiana 46204

Michael R. Pence
Governor

March 27, 2014

President Pro Tempore David Long;
Speaker Brian Bosma;
Senator Jim Merritt,
Representative Eric Koch;

Dear Legislative Leaders:

I am writing regarding my decision concerning SEA 340.

I could not sign this bill because it does away with a worthwhile energy efficiency program developed by the prior administration. I could not veto this bill because doing so would increase the cost of utilities for Hoosier ratepayers and make Indiana less competitive by denying relief to large electricity consumers, including our state's manufacturing base.

Managing the demand-side of our electricity industry through energy efficiency is an important part of our energy strategy. I speak often of the need for an 'all of the above' energy strategy, and I include energy efficiency in my definition of 'all of the above.'

Accordingly, I have requested the Indiana Utility Regulatory Commission to immediately begin to develop recommendations that can inform a new legislative framework for consideration during the 2015 session of the Indiana General Assembly. This request is in addition to and builds upon the IURC's status report required under SEA 340.

I look forward to working with you to develop a new energy efficiency program for our state that will encourage conservation and promote a strong Indiana economy.

Sincerely,

Michael R. Pence
Governor of Indiana