COMMENTS OF CITIZENS ACTION COALITION OF INDIANA, EARTHJUSTICE, INDIANA DISTRIBUTED ENERGY ALLIANCE, AND SIERRA CLUB

INTRODUCTION

Pursuant to the Indiana Utility Regulatory Commission's ("IURC" or "Commission") Integrated Resource Planning Rule, 170 IAC 4-7,[1] Citizens Action Coalition of Indiana, Inc. ("CAC"), Earthjustice, Indiana Distributed Energy Alliance ("IndianaDG"), and the Sierra Club—Hoosier Chapter (collectively, "Commenters") hereby submit the following comments on the 2014 Integrated Resource Plans ("IRP") submitted by Indianapolis Power & Light ("IPL"), Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Incorporated ("Vectren"), and Northern Indiana Public Service Company ("NIPSCO").

As last year's Commission Staff report observed, the IURC established an IRP process for Indiana utilities "to better ensure that electric utility services would be provided to Indiana citizens at the lowest reasonable cost consistent with reliable service."[2] The most recent revisions to the IRP rule were intended to recognize the increasing regional interconnectedness of Indiana utilities, and to facilitate a collaborative process for evaluation of the potential ramification of 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 last year in evaluating the 2013 IRPs, "continual efforts to improve the quality and credibility of the IRPs are warranted by the extraordinary risks faced by utilities over the next 20 years or more."[4]

Increased reliance on clean energy resources makes economic sense for Indiana utilities and ratepayers and lowers system-wide risk. However, as detailed below, the three utilities submitting IRPs in 2014 each undervalue, and in some cases disregard, clean, low-cost energy resources by failing to analyze demand-side and supply-side resource alternatives on a consistent and comparable basis. The utilities failed to reflect all available, economical demand-side management, distributed generation, and other renewable resource alternatives in their IRP modeling, failed to evaluate fairly and transparently the potential benefits to their ratepayers of retiring coal-fired generating units, and failed to account for all of the costs and risks facing coal-fired generating units from future environmental regulations.

In order to assist Commission Staff in developing its report on the 2014 IRPs, Commenters have organized their comments based on an evaluation of the IPL, Vectren, and

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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 Report of the IURC Electricity Division Director Dr. Bradley K. Borum Regarding 2013 IRPs, p. 1 (Apr. 30, 2014) ("2013 IRP Report"), 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] 2013 IRP Report at 2.
[3] 2013 IRP Report at 3-4.
[4] 2013 IRP Report at 4.

NIPSCO IRPs' compliance with specific informational, procedural, and methodological requirements of the draft proposed IRP rule. The below 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 and urge the Commission Staff to address in its report. Commenters respectfully request that Commission Staff call on IPL, Vectren, and NIPSCO to address these informational, procedural, and methodological deficiencies both in 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 IPL, Vectren, and NIPSCO for their willingness to provide responses to informal discovery requests following the submission of their IRPs that assisted Commenters in understanding each utility's IRP process. We do not attempt to provide here a comprehensive evaluation of how the IRP process is working in Indiana under the draft proposed rule, but we would welcome the opportunity to meet with Commission Staff, utilities, and other interested parties in the future to discuss how the process could be improved. While we appreciate the willingness of utilities to date (both this year and last year) to share information with stakeholders informally, we believe that adopting a formal discovery process as part of the IRP rule would enhance opportunities for broad, consistent public participation in the process in years to come.

COMMENTS

A. The Role of Energy Efficiency in Long-Term Planning.

Energy efficiency is the least-cost system resource. Energy efficiency meets system needs by reducing demand for energy. And efficiency resources do so at a substantially lower cost than generating energy from power plants. As discussed during the 2014 IRP Contemporary Issues Meeting, "[i]n virtually all cases today, it is much cheaper to reduce customer demand than to acquire new supply resources."[5]

Two recent studies illustrate the tremendous value that energy efficiency resources have provided. A 2014 report by the American Council for an Energy-Efficiency Economy ("ACEEE") found that electric energy efficiency programs have an average cost of 2.8 cents per kilowatt-hour ("kWh"), based on 2009-2012 data.[6] Similarly, a 2014 study from the Lawrence Berkeley National Laboratory, associated with the U.S. Department of Energy, found that the national levelized cost of energy savings for electric utilities administering efficiency programs

[5] Martin Kushler, Ph. D, Energy Efficiency as a Utility System Resource: Some Thoughts on Best Practices for IRP, EM&V, and Regulatory Policy, slide 5, American Council for an Energy-Efficient Economy ("ACEEE"), presentation at IURC Contemporary Issues Technical Conference (Oct. 23, 2014) ("Kushler IURC Presentation"), available at http://www.in.gov/iurc/files/ACEEE_2014_IRP_Presentation.pdf.

[6] Maggie Molina, The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs, p.19 tbl. 3, ACEEE (Mar. 2014), available at http://www.aceee.org/research-report/u1402.

from 2009-2011 was just 2.1 cents per kWh.[7] Energy efficiency is roughly 2-3 times cheaper than traditional supply-side options.[8]

Not only is efficiency the least cost resource, it carries the least risk. Energy efficiency is a clean resource that can defer or avoid the need for generation and related infrastructure. Thus, the risks of fuel cost increases, construction delays and rising environmental compliance costs, for example, are mitigated by increased reliance on energy efficiency. These attributes make efficiency an integral part of a utility's resource mix that can lower overall system cost and risk in addition to reducing customer bills and moderating rates over the long term.

The Commission has 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."[9] The IRP rule ensures such utilization by requiring Indiana's utilities to demonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis, and that their preferred resource portfolios utilize, to the extent practical, all economical load management, demand side management ("DSM")[10] and energy efficiency improvements as sources of new supply. 170 IAC 4-7-8(b)(3),(4). Utilities must also discuss the inputs and methods used in the IRP. *Id.* at § 4-7-4(b)(1).

Now is a critical time for energy efficiency resource planning in Indiana. The electric savings goals set by the Commission in 2009 paved the way for significant increases in cost-effective energy savings.[11] Indeed, since the Commission issued its Phase II Order, the amount of savings that Indiana utilities achieved has grown substantially each year.[12] Savings levels in 2013 were 73 times greater than they were in 2008,[13] and they provided great value to customers and utilities. In 2012 and 2013, the statewide Core programs generated as much as $3 in benefits for each dollar spent, in aggregate.[14] Moreover, all of the individual utility Core Plus program portfolios generated net benefits.[15]

However, the efficiency landscape in Indiana has changed significantly and Indiana's steady progress over the last five years appears in jeopardy. On March 28, 2014, the General

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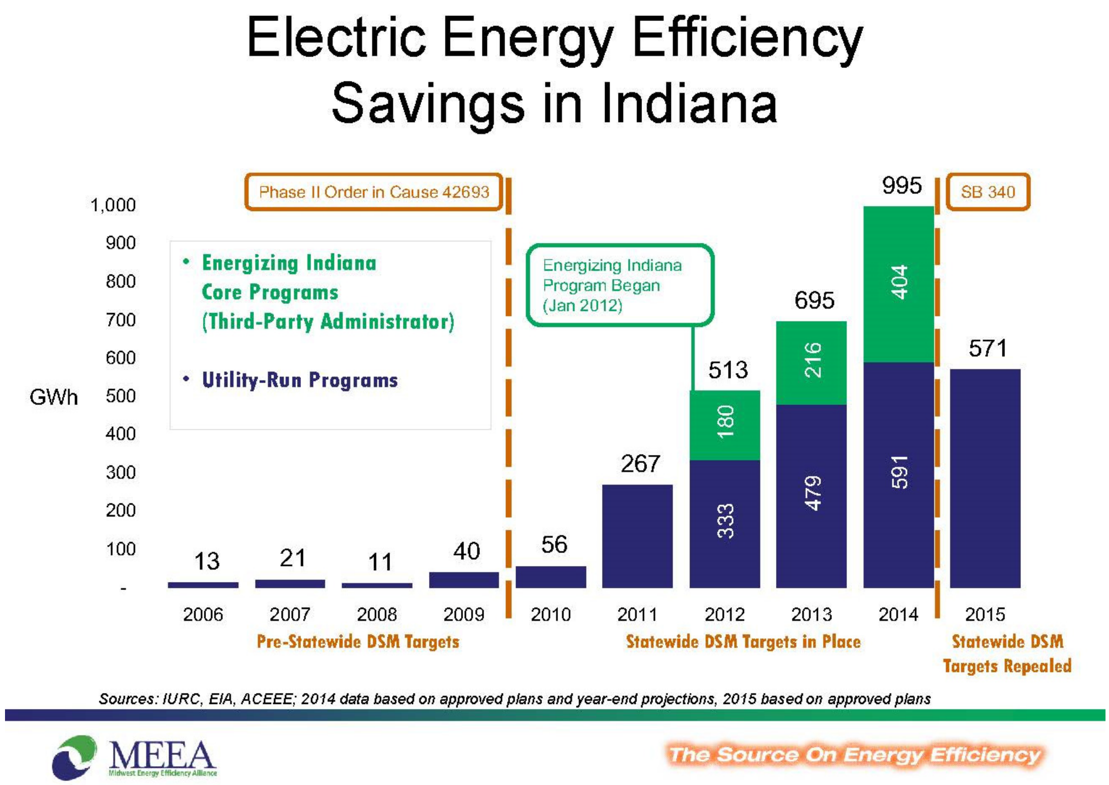
[7] Megan A. Billingsley *et al.*, The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs, p. xi tbl.ES-1, Ernest Orlando Lawrence Berkeley National Laboratory (Mar. 2014), available at http://emp.lbl.gov/sites/all/files/lbnl-6595e.pdf. This cost of saved energy estimate is based on program administrator costs (in 2012 $) and levelized gross savings.
[8] Molina at 34-35; *see also* Kushler IURC Presentation at slide 7.
[9] Phase II Order, p. 30, IURC Cause No. 42693 (Dec. 9, 2009).
[10] DSM, or demand-side management, is the planning, implementation, and monitoring of a utility activity that is designed to influence customer use of electricity and produces a desired change in a utility's load, and includes energy efficiency and demand response programs. 170 IAC 4-7-1(j).
[11] *See* Phase II Order, p. 31, IURC Cause No. 42693 (Dec. 9, 2009).
[12] Midwest Energy Efficiency Alliance (MEEA), Factsheet: Analysis of Energizing Indiana (2014), http://www.mwalliance.org/sites/default/files/uploads/MEEA_2014_Analysis-Energizing-Indiana.pdf.
[13] *Id.*
[14] Steve Kihm and Melanie Lord, Indiana's Core and Core Plus Energy Efficiency Programs: Benefits, Costs and Savings, Energy Center of Wisconsin, p. 5 (Aug. 14, 2014), available at http://www.in.gov/iurc/files/DSM_Report_to_General_Assembly_w_Cover_Letter_8-15-2014(2).pdf.
[15] *Id.* at 9.

Assembly enacted Senate Enrolled Act ("SEA") 340.[16] This law eliminated the Phase II goals, allowed for certain large customers to opt out of utility DSM programs, and discontinued statewide programs administered by a third-party. SEA 340 altered Indiana's energy picture almost immediately. Within nine weeks of its enactment, all five of Indiana investor-owned utilities ("IOUs") filed efficiency plans projecting 2015 savings levels that are, in aggregate, nearly 50% lower than the Phase II goal that was set for 2015 and more than 40% below 2014 savings levels, as illustrated below.[17] The IOUs' 2015 savings goals are now comparable to levels achieved in 2012.[18]



The projected drop in energy efficiency savings comes at a time when utilities in Indiana should instead look to scale up their efficiency investment. This is especially true in light of the

[16] SEA 340 is available at http://www.in.gov/iurc/files/SEA_340.pdf.
[17] The IOUs' 2015 DSM filings are available at the Commission website under the following cause numbers: 43955 DSM 2 (DEI), 44486 (I&M), 44497 (IPL), 44496 (NIPSCO), and 44495 (Vectren). *See also* Kushler IURC Presentation at slide 40; MEEA, Indiana Thought Leadership Roundtable, slide 16 (July 17, 2014), available at http://www.mwalliance.org/sites/default/files/uploads/MEEA_2014_Indiana-Thought-Leadership-Roundtable_July2014_final-presentations.pdf; and Citizens Action Coalition Inc.'s Written Comments Pursuant to General Administrative Order 2014-1, pp. 4-5 (June 10, 2014), available at http://www.in.gov/iurc/files/Citizens_Action_Coalition_Comments_and_Resident_Email.pdf.
[18] The impact of SEA 340 was recognized by efficiency experts. Indiana dropped 13 spots to number 40 in ACEEE's 2014 State Energy Efficiency Scorecard, the largest decrease of any state. Annie Gilleo, *et al.*, The 2014 State Energy Efficiency Scorecard, ACEEE (Oct. 2014), p. 14, available at http://www.aceee.org/sites/default/files/publications/researchreports/u1408.pdf.

increasing need to reduce carbon emissions. EPA has recognized the important role efficiency can play in reducing carbon emissions. In its proposed Clean Power Plan, energy efficiency is one of the four building blocks EPA used to set state emission reduction goals. EPA has determined that a 1.5% annual incremental savings rate can be achieved at reasonable costs over a period of years, with savings increasing by 0.2% each year starting in 2017.[19] In Indiana, this translates to total savings of 3.2% and 11.1% by 2020 and 2029, respectively.[20] While EPA's proposal is not final and it would allow each state to develop its own compliance plan, energy efficiency represents a low-cost, "no regrets" strategy to reduce carbon emissions that can lower overall utility system costs.[21]

Now is the time for Indiana utilities to ramp up, rather than scale back, their investment in cost-effective energy efficiency resources. A critical piece of this effort is the IRP process. As discussed in the 2012 IRP Contemporary Issues Technical Conference, "proper consideration of demand side management ('DSM") is important because it can postpone or eliminate the need for additional generation resources and lower customer bills overall.[22] In developing long-term plans to meet the needs of customers in an affordable and reliable manner, utilities must comprehensively and fairly evaluate energy efficiency to fully capture the benefits that this resource provides.

B. Resource Integration Requirement: 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)*).

IPL

1. In contrast to its treatment of supply-side options, IPL treats energy efficiency as a fixed load adjustment that cannot be selected as a resource option.

A core requirement of long-term planning under the IRP Rule is that energy efficiency and other demand-side resources must be treated on equal footing with supply side resources. 170 IAC 4-7-8(b)(3). Put simply, energy efficiency must be treated as a true resource that can be selected whenever cost-effective, rather than a hard-wired adjustment to the load forecast that cannot compete with other resources. While methods of evaluation may vary, "it is indisputable that utilities in their IRPs must attempt to evaluate supply-side and demand-side resources in something resembling a comparable manner."[23]

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[19] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule, 79 Fed. Reg. 34,830, 34,873 (June 18, 2014), available at http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf. 79 Fed. Reg. 34,830, 34,872/3 (June 18, 2014).
[20] *Id.* at 34,873.
[21] *See, e.g.*, Tim Woolf *et al.*, Unleashing Energy Efficiency: The Best Way to Comply with EPA's Clean Power Plan, Public Utilities Fortnightly, p. 32/1 (Oct. 2014), available at http://synapse-energy.com/sites/default/files/Unleashing%20Energy%20Efficiency%2014-093.pdf.
[22] Summary of IRP Contemporary Issues Technical Conference, p. 4 (Oct. 18, 2012), available at http://www.in.gov/iurc/files/Summary_of_IRP_Contemporary_Issues_Technical_Conference_held_on_Oct_18_2012.pdf .
[23] 2013 IRP Report at 4-5.

IPL incorporates efficiency in its net internal demand ("NID") forecast, which is set before supply side options are evaluated through scenario resource modeling. IPL IRP at 9, 42-43, 46. The NID includes projected savings from IPL's 2014 DSM programs, its 2015-17 proposed programs and its long-term DSM potential forecast. *Id.* at 46. Modeled this way, IPL treats energy efficiency as a fixed load adjustment that cannot increase based on need or compete with other resource options. Simply put, IPL "does not optimize energy efficiency by letting efficiency compete with supply-side resources."[24]

IPL's approach is inconsistent with the purpose of the IRP Rule, which requires that a utility "[d]emonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis." 170 IAC 4-7-8 (b)(3). As discussed during the 2012 IRP Contemporary Issues Technical Conference, "[t]he intent of the revised IRP Rule is to have demand-side resources compete with supply-side resources in the IRP, *not simply subtracting a value from the forecast*."[25]

IPL maintains that it evaluates supply-side and demand-side resource alternatives on a consistent and comparable basis. IPL IRP at 46. Specifically, IPL states that the outcome of its PVRR analysis of the production cost model and its DSM cost-effectiveness evaluations are "aligned" because the Company uses the same cost inputs for both models. *Id.* However, the Company's treatment of DSM in its PVRR analysis stands in stark contrast to its treatment of supply side resources. Based on its capacity expansion modeling, IPL developed five scenario resource plans to determine the impact of retiring Petersburg 1 and 2. *Id.* at 58. Whereas supply-side options varied across the five plans, energy efficiency resources did not. The Company did not evaluate a single resource plan that included more efficiency than what IPL included in its NID forecast. IPL developed high and low load scenarios for its IRP modeling, which *could* be driven by varying DSM levels. *Id.* at 52-53. However, IPL did not consider these scenarios in the PVRR scenario analysis because it reasoned that "load variance does not impact the dispatch or costs of resources." IPL IRP at 65.[26] Thus, IPL's PVRR resource plan analysis included the same amount of DSM in each plan studied while supply-side resources varied across the plans. This is not comparable treatment.

IPL concludes that "[t]heoretically, a model including DSM as an optional choice would likely not choose DSM" because IPL needs to mitigate environmental regulatory risks through generation additions and retrofits in the short term. *Id.* at 46. Because this mitigation plan will result in excess capacity, IPL reasoned, DSM would not be selected. *Id.* at 46. However, environmental regulatory risks are a key reason why IPL should evaluate higher levels of efficiency. Energy efficiency is one of the cleanest energy resources available. Among its many environmental benefits, energy efficiency reduces air pollution, greenhouse gases and water

[24] 2013 IRP Report at 5.
[25] Summary of IRP Contemporary Issues Technical Conference, p. 4 (Oct. 18, 2012), available at http://www.in.gov/iurc/files/Summary_of_IRP_Contemporary_Issues_Technical_Conference_held_on_Oct_18_2012.pdf (emphasis added).
[26] Moreover, the high and load ranges were "developed primary based upon economic uncertainty." IPL IRP at 52.

use.[27] This is why EPA has identified efficiency as one of the major tools to reducing carbon emissions. Contrary to IPL's assertion, the need to mitigate environmental risks supports the inclusion of DSM in an IRP model.

Finally, in describing its DSM evaluation process, IPL presented its "Customer Balance Test" as a way to "assess the degree of subsidization between participants and non-participants." IPL IRP at 111. Although DSM programs are not individually screened or modeled in the IRP, IPL's discussion of its CBT concept highlights the importance of comparable evaluation of supply and demand-side resources in this regard. As explained in the Commission's August 15, 2014 DSM Report to the Indiana General Assembly (prepared by the Energy Center of Wisconsin):

> [W]hen looking at economic winners and economic losers, we have to remember that almost any action that a utility takes has differential impacts on customers. This is true for both supply-side and demand-side activities. We have shown how this occurs for demand-side resources. The impact on the supply-side is at the same time more subtle to detect and more significant in terms of the magnitude of the impact.
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> As demand grows, utilities tend to add new generation facilities. Since ratemaking is based on historical costs of building facilities, the cost of new plant (recorded in today's dollar) is often much more expensive than the original cost of the existing plant, which might for example have been built in the 1970s. Therefore, the addition of new plant can put substantial upward pressure on utility rates.
>
> But the need for new plant may be due to the increased demand for only a handful of customers, and in some cases a single customer. If a new manufacturing plant locates in a utility service area, the utility may have to add capacity, which in turn increases rates. Capacity costs tend to be spread across all customers. The new customer gets service but some of the costs of expanding system capacity are likely to be allocated to the existing customers, those who did not need new capacity absent the arrival of the new manufacturer. While the community likely benefits economically from the arrival of the new facility, the existing ratepayers will see both higher rates and bills when the utility adds capacity to serve the customer. *To identify winners and losers on the demand-side, but ignore them on the supply-side, raises equity concerns*.[28]

In sum, IPL failed to evaluate energy efficiency on a consistent and comparable basis with supply-side resources. The Company should remedy this critical flaw in its planning methodology.

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[27] Energy Efficiency: Reduce Energy Bills, Protect the Environment, pp. 1, 3, National Action Plan for Energy Efficiency, available at http://www.epa.gov/cleanenergy/documents/suca/consumer_fact_sheet.pdf.

[28] Steve Kihm and Melanie Lord, Indiana's Core and Core Plus Energy Efficiency Programs: Benefits, Costs and Savings, Energy Center of Wisconsin, p. 523 (Aug. 14, 2014), available at http://www.in.gov/iurc/files/DSM_Report_to_General_Assembly_w_Cover_Letter_8-15-2014(2).pdf (emphasis added).

2. *IPL failed to adequately evaluate renewable resources.*

The IRP Rule requires each utility to 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). This requires consistent and comparable treatment not only between supply and demand resources but within the category of supply-side resources. *See id.* Yet IPL appears to view renewable resources as fundamentally different from other supply-side resources. According to IPL, "[r]enewables technologies represent a resource that primarily targets potential future requirements for GHG regulation, and specifically any federal or state RES legislation." IPL IRP at 80.

This statement is troubling because it suggests that IPL does not view renewable technologies such as wind and solar as resources to be considered on the same basis as other supply-side resources. Instead, IPL appears to view renewables as not being "real" supply-side resources, since they are "primarily" useful in meeting regulatory or legislative requirements. Of course, it is appropriate to consider how renewables can be used to comply with regulatory requirements; for example, utilities should consider how renewables can help a state comply with the Clean Power Plan's mandate to reduce the carbon emissions rate. However, the way to consider regulatory requirements is through constructing appropriate modeling scenarios. Once those scenarios are constructed, all supply and demand resources should be evaluated based on the same metrics. Treating renewables as somehow different from and inferior to other supply-side resources is inconsistent with the IRP Rule, which requires that all supply-side resources be evaluated on a consistent basis. *See* 170 IAC 4-7-8(b)(3).

Vectren

1. *Vectren failed to examine the economics of retiring existing units other than FB Culley 2.*

Vectren's IRP treats certain existing resources preferentially, which violates the requirement to evaluate all resources on an even playing field. Vectren's IRP modeling examined only one plan in which any existing units were retired, the "FB Culley Unit 2 Retirement Scenario" in which FB Culley 2 is retired in 2020. *See* Vectren IRP at 193-194. Vectren provides no explanation for failing to analyze scenarios in which another existing unit is retired early. Given that Vectren's modeling shows an economic benefit to retiring FB Culley Unit 2 in 2020, *id.* at 25, the modeling may have yielded similar results for other units. Vectren should have modeled scenarios in which units other than FB Culley 2 retire early, or, at a minimum, justified its assumption that a portfolio that retains all existing units other than FB Culley 2 is the economically optimal portfolio.

2. *Vectren modeled additional DSM as a resource option but the plan's underlying assumptions raise concerns.*

As with IPL, Vectren hard wired a base level of DSM into the load forecast. Vectren included in its base load forecast "a targeted level of 1% eligible annual savings for 2015-2019 and 0.5% annually thereafter for customer load that has not opted-out of DSM programs."

Vectren IRP at 25. Vectren assumed an opt out rate of 70% throughout the planning period. *Id.* at 132. Therefore, the 1% and 0.5% savings blocks amount to 1% and 0.5% of retail sales minus 70% of large customer load, respectively. The IRP is unclear as to how the Company developed its base DSM forecast. It appears that Vectren relied on its 2013 market potential study, conducted by Enernoc,[29] and its 2015 DSM plan. However, Vectren's most recent DSM plan covers 2015 only and the potential study focuses on 2015-2019. *Id.* at 134-35. Vectren should clarify the role of its potential study in the IRP and explain how exactly it developed its base DSM forecast.

In addition to the base level of DSM, Vectren modeled additional increments of efficiency that competed with supply-side resources. Vectren IRP at 25. Vectren created blocks of DSM representing savings equal to 0.5% eligible retail sales, assuming that 80% of large customers opt out of DSM participation. *Id.* at 172. Vectren capped the amount of additional DSM that the model could select to 2% in 2018-2019 and 1.5% after 2019, including embedded and additional DSM. *Id.*[30] The levelized costs of the additional DSM began at roughly $0.03 per kWh, the cost of the 2015 DSM plan, and increased to $0.064 per kWh, based on estimates from Vectren's 2015 plan and potential study. *Id.* at 172. Additional DSM was selected in several resource plans that the Company evaluated but not in the selected portfolio.

Vectren's DSM opt out and cost assumptions raise concerns. As discussed in more detail below, Vectren's 70% and 80% opt out rates leave a substantial amount of cost-effective efficiency on the table and do not appear to consider customers opting back in, improved industrial offerings, or a self-direct program. Vectren also projected that the cost of efficiency more than doubles over the twenty-year plan. Vectren stated that the costs were based on its potential study and 2015 plan, but the derivation of the cost assumptions over the planning period should be further explained.

Additionally, Vectren failed to justify the limits it places on how much additional DSM can be selected, which constrains the resource in the model. Vectren only noted that the 1.5% limit is consistent with EPA's Clean Power Plan. Vectren IRP at 172. Instead of putting a ceiling on efficiency, Vectren should let the model select the maximum amount of additional efficiency blocks that is optimal.

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[29] Vectren IRP at Technical Appendix D.

[30] Although the first cap on additional DSM applies beginning in 2018, the model allows additional blocks of DSM to be selected immediately. Vectren IRP at 172, 198. Indeed, the model selected additional DSM blocks in 2015 and 2017 in two scenarios. *Id.* at 196, 198.

3. Vectren [redacted]

[redacted]

By contrast, in its 2014 IRP, IPL considered wind energy that could be delivered into Indiana when the Clean Line high-voltage transmission line linking Kansas to Indiana is completed. IPL noted that the Clean Line transmission project will make wind with a 50% capacity factor available in Indiana, IPL IRP at 72, which is nearly double the 27% capacity factor wind that Vectren modeled. Vectren IRP at 106. IPL noted that the "The Clean Line Energy representative discussed utilities could purchase this energy via a PPA for $45/MWH." IPL IRP at 72.

[redacted]

<u>NIPSCO</u>

1. NIPSCO failed to examine the economics of retiring existing coal units in a consistent manner.

Like Vectren, NIPSCO in its IRP does not consistently evaluate retirements of its existing coal-fired generating units on a level playing field with other, potentially less expensive, resources. Although NIPSCO does not provide a detailed explanation of this in its IRP, NIPSCO appears to have failed to model the possibility of retiring each of its units (and thereby avoiding the costs of any additional capital investments needed to continue to operate those units) in each year where such a retirement would be possible. On the contrary, NIPSCO appears to have placed an arbitrary constraint on its modeling of retirement alternatives, hard-wiring its model to assume that while Bailly Unit 7 could be retired as soon as 2016, the model did not have the option to consider retiring Bailly Unit 8 until 2026[31] and did not have the option of retiring Michigan City Unit 12 until 2030. NIPSCO IRP at 105 (Table 9-1).

The IRP provides no explanation as to NIPSCO's basis for, apparently, placing such arbitrary constraints on the modeling of the potential benefits to its customers of an earlier retirement of either Bailly Unit 8 or Michigan City Unit 12. In addition, NIPSCO did not model the possibility of retiring any units at the Schahfer facility during the planning period. NIPSCO

[31] On page 109 of the NIPSCO IRP, in footnote 8, it lists 2016 as the earliest available retirement date for Bially Unit 8. It is not clear from the IRP which of these two dates is correct.

Response to CAC/EJ Informal Request 2-009 (attached as Exhibit A). A more rigorous analysis would place no arbitrary constraints on the modeling of the possibility of retirement of each of NIPSCO's units, in order to evaluate the robustness of NIPSCO's preferred resource portfolio and ensure that it reflects an optimal balancing of cost minimization with cost-effective risk and uncertainty reduction. The Commission Staff should call on NIPSCO, in any future filings, to do a more robust modeling of potential retirements of its existing coal-fired generating units by modeling the option to retire each existing unit starting the first year that the unit is able to retire.

2. NIPSCO should clarify its evaluation of energy efficiency resource options.

NIPSCO filed for approval of a suite of DSM programs for 2015 shortly after SEA 340 was enacted. The Company's 2015 Plan includes 12 programs that are projected to save 120 GWh. NIPSCO IRP at 51. NIPSCO's consideration of DSM resources for the remainder of the IRP planning period, 2016-2035, appears unclear. In its discussion of 2016-2035 resources, NIPSCO stated that it commissioned a DSM potential study to identify measures appropriate for its service territory. *Id.* at 51. The study found that NIPSCO had an achievable savings potential of 7%, or 1,238 GWh, by 2035. *Id*. at Appendix G, p. 4. NIPSCO then screened measures in the DSMore model. *Id.* at 51. However, it is unclear which measures were screened. It appears that the screened measures include those identified as achievable in the DSM Study but the IRP also states that all DSM Core Plus programs are evaluated for inclusion in the IRP via DSMore. NIPSCO should clarify the DSMore screening process.

After the DSMore screen, the Company grouped the measures by end use and sectors. Table 5-15 provides the projected cumulative savings for seven aggregated end use sectors. By the end of the IRP planning period, the measures are expected to save 1,639 GWh. *Id.* at 53. It is unclear how this cumulative savings projection relates to the lower potential study projection (1,238 GWh) and what accounts for the difference between the two estimates. NIPSCO should explain the difference.

NIPSCO evaluated the seven aggregated end use sectors as resource alternatives in its integration analysis. *Id.* at 105. As part of this analysis, NIPSCO set "optimization constraints" and "continually screen[ed] the alternatives" to narrow the number of resource options. *Id.* at 106. The details of the constraints and continual screening process, and how that impacts energy efficiency resources, is unclear and should be explained. NIPSCO should not constrain DSM in its modeling.

C. Resource Integration Requirement: Utilities must demonstrate that the preferred resource portfolio utilizes, to the extent practical, all economical load management, demand side management technology relying on renewable resources, cogeneration, distributed generation, energy storage, transmission and distribution, and energy efficiency improvements as sources of new supply. (*170 IAC 4-7-8(b)(4)*).

IPL

1. *IPL's declining savings projection does not reflect all economical DSM and raises concerns about IPL's efficiency potential forecast.*

IPL incorporates a 20-year projection of DSM savings in its NID forecast. IPL IRP at 81. IPL's short-term DSM estimates (through 2017) reflect IPL's 2015-2017 DSM plan. *Id.* at 114, 120. The long-term estimate (2018-2034) is based on a potential forecast by Applied Energy Group ("AEG"). *Id.* at 120, Attachment 4.7.

Based on its projections, IPL appears to be heading in the wrong direction on efficiency, falling short of utilizing all economical energy efficiency. IPL projects total three-year savings of just 379 GWh. This is a reduction of 277 GWh, or 42%, as compared to IPL's prior goal under the Phase II Order, as illustrated below.

Difference Between IPL Phase II Goal & 2015-17 Action Plan (Annual GWh)[32]

	IPL's Phase II Goal	**2015-2017 Action Plan**	**Difference**
2015	186	123	63
2016	218	126	92
2017	252	130	122
2015-2017 Total	656	379	277

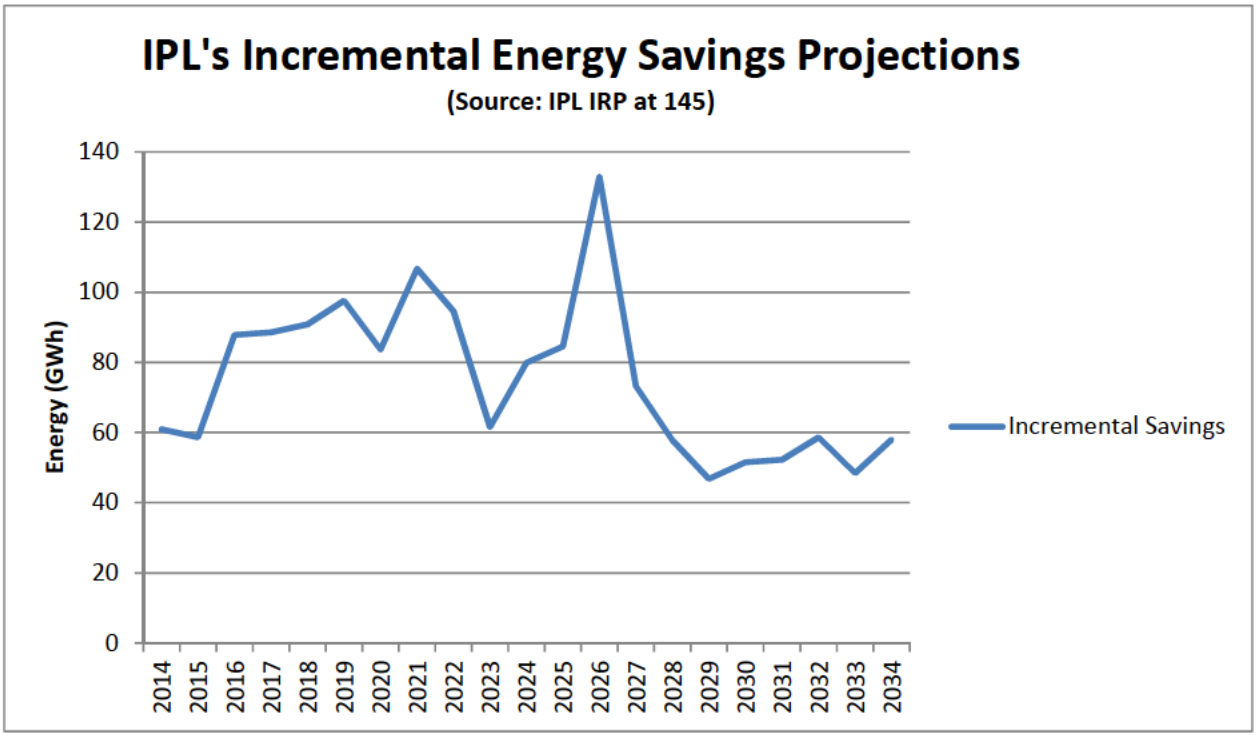
IPL updated its short-term efficiency plan after SEA 340 was enacted. The result is substantially lower savings projections. For example, as a result of SEA 340's opt out provision, IPL estimated that annual savings for the Business Prescriptive program will decrease by 20% as compared to 2014. IPL IRP at 157. IPL notes that a reduction in DSM potential due to the opt outs "may be mitigated to the extent that large customers create energy efficiency projects on their own." IPL IRP at 104. While some of IPL's industrial customers may pursue energy efficiency projects on their own, it is important that IPL incorporate the load impact from such projects in its IRP. Customers who opt out remain part of the interconnection electric system and resource planning should take these customers' load and savings into account.[33]

[32] IPL IRP at 114; MCR Performance Solutions, LLC, Indiana Demand Side Management Coordination Committee Core Portfolio Report, p. 11, IURC Cause No. 42693-S1 (June 19, 2013), available at https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631801a1dfc.

[33] *See, e.g.*, IURC letter to Gov. Pence, p. 9 (Oct. 9, 2014), available at http://www.in.gov/iurc/files/2014-10-09_Ltr__to_Governor_Re__EE-DSM_(2).pdf; *See also* Commission Order, p. 5, Cause No. 44441 (Sept. 3, 2014)

Moreover, SEA 340's opt out provision does not mean that IPL and other utilities should scale back their efforts to capture industrial efficiency savings. The industrial customer sector represents roughly 47% of energy sales in Indiana (27% in IPL's service territory),[34] and provides substantial energy efficiency savings opportunities. At this early stage, customers representing roughly 12.5% of IPL's total retail sales have opted out of participating in DSM programs, which amounts to a 50% opt out rate. IPL IRP at 104. As discussed below, IPL has applied this opt out rate to its DSM potential forecasts beyond 2017. IPL should develop a strategy to achieve industrial efficiency savings and encourage customers to opt in. Another option is self-direct programs, in which the DSM fees the customer would otherwise pay are invested in energy efficiency projects in their own facilities.[35]

In the long term, IPL projects a decline in annual savings over time (though not steadily). IPL IRP at 145. The end result is a cumulative savings projection of roughly 10%, or 1575 GWh, by 2034. *Id.* at 121, 145.



As the above chart illustrates, the final seven years of the forecast period account for the seven lowest annual savings projections. This decline in growth is contrary to the experience of electric utilities that have been utilizing energy efficiency programs to save energy for decades.

(noting that issues raised by CAC, including whether and how energy and demand savings from industrial customers that opt out can be used by regulated electric utilities in the IRP process, may be appropriate for consideration in other Commission proceedings, such as in a utility's IRP process for stakeholder input).

[34] U.S. Energy Information Administration, Indiana State Profile and Energy Estimates, available at http://www.eia.gov/state/?sid=IN#tabs-2; IPL IRP Attachment 4.7 at 3-1.

[35] An investigation into self-direct programs is currently pending before the Commission. *See* Cause No. 44310.

Other regions of the country with a long history of substantial efficiency savings continue to save energy at high levels through efficiency programs and plan to do so long into the future. In the Pacific Northwest region, for example, energy efficiency has been used to meet more than 60% of its load growth since 1980 and was the second largest resource in 2012.[36] The most recent power plan from the Northwest Power and Conservation Council projects that cost-effective, available energy efficiency will meet 85% of the region's growing power needs through 2030.[37] IPL's downward savings trend – especially at such a low level – is alarming and symptomatic of inadequate evaluation and integration of efficiency resources.

IPL modeled efficiency in the long term by incorporating AEG's DSM potential forecast in the IRP. IPL IRP at 145.[38] To arrive at the DSM potential forecast, AEG estimated what it called the "realistic achievable potential," which includes a subset of cost-effective DSM measures based on assumptions about customer adoption. IPL IRP Attachment 4.7 at 1-1. AEG calibrated the DSM potential forecast to IPL's 2015-2017 plan. *Id.* at 2-3. In so doing, AEG excluded potential savings from 25% of commercial and industrial customers based on IPL's current opt out rates. *Id*. The DSM potential forecast that reflects only about 43% of the savings that AEG estimated can be achieved by all cost-effective efficiency. *Id.* at A-1.[39] In fact, IPL's potential forecast is among the lowest when compared to the results of recent long-term potential studies.[40] A 2014 ACEEE report reviewed 45 publicly available studies published since 2009 and found that overall, for electricity, the average *annual* maximum achievable savings range from 0.3% to 2.9% with a median of 1.3%.[41] AEG's DSM potential forecast projects average annual savings of 0.47%. IPL IRP Attachment 4.7 at A-1.[42] For long-term potential studies (with an analysis period of 16 years or more), the report found that the average cumulative medium achievable potential reported, where reported, is roughly 17%.[43] By contrast, AEG's DSM potential forecast projects 10.4% savings over 22 years.

Taken together, IPL's projected decline in annual savings and low cumulative savings forecast results in a preferred resource portfolio that falls short on efficiency, depriving customers of significant energy savings. In addition to improving the way it models DSM, IPL should continue to pursue cost-effective energy efficiency opportunities for all customer classes, including large commercial and industrial customers.

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[36] Northwest Power and Conservation Council, Progress Toward the 6th Plan's Regional Conservation Goals, slides 10, 12 (Oct. 2014), available at http://www.nwcouncil.org/media/7148388/2.pdf.
[37] Sixth Northwest Conservation and Electric Power Plan Overview, p.1, http://www.nwcouncil.org/media/6383/SixthPowerPlan_Overview.pdf.
[38] IPL adjusted AEG's forecast "to account for prorated implementation of programs and the fact that the base forecast has historical DSM (up till 2014) embedded in it owing to the use of actual historical consumption data." IPL IRP at 145.
[39] Table 5-1 of AEG's DSM Potential Forecast shows that the economic and realistic achievable forecasts project 24.5% and 10.4% energy savings (as a % of baseline) by 2034, respectively. *Id.*
[40] Max Neubauer, Cracking the TEAPOT: Technical, Economic, and Achievable Energy Efficiency Potential Studies, ACEEE, Report U1407 (Aug. 2014), available at http://www.aceee.org/sites/default/files/publications/researchreports/u1407.pdf.
[41] *Id.* at iv, v.
[42] This calculation is based on a 22-year forecast period. AEG states that the potential forecasts in the model begin in 2013. IPL IRP Attachment 4.7 at A-1
[43] Neubauer at 72. This average increases to 18.9 when one outlier study is removed.

2. *IPL improperly dismissed the Clean Line project as a viable option.*

The IRP Rule requires each utility to demonstrate the preferred portfolio uses, to the extent practical, all economical renewable resources. 170 IAC 4-7-8(b)(4). IPL evaluated wind energy as a supply-side resource in its IRP. IPL assumed that wind would achieve a 35% capacity factor, but IPL conducted sensitivity analyses to account for variations in the performance of wind in different locations and with storage technologies. IPL IRP at 72-73. IPL considered wind energy that could be delivered into Indiana when the Clean Line transmission line linking Kansas to Indiana is completed. IPL noted that the Clean Line transmission project will make wind with a 50% capacity factor available in Indiana, *id.* at 72, which is significantly higher than the 35% capacity factor that IPL used as the default in its modeling. *See id.* at 79. "The Clean Line Energy representative discussed utilities could purchase this energy via a PPA for $45/MWH." *Id.* at 72.

After examining the effect of the different wind options, IPL concluded that the "case with the lowest PVRR signifies the Clean Line Energy PPA." IPL IRP at 73. IPL should be commended for examining wind potential both inside and outside Indiana, and for examining the economics of importing wind energy from states with high-capacity factor wind.

However, the results of IPL's wind sensitivity modeling do not flow through to other sections, and IPL dismisses the Clean Line project as a viable option. IPL states that "[d]espite significant progress, there is still uncertainty surrounding the DC transmission line construction. IPL will continue to analyze and monitor the progression of transmission capability and technology improvements in the wind industry." *Id.* IPL ultimately rejected Plan 2, the plan that adds 200 MW of wind in 2025, on the ground that wind farms in Indiana have not been able to achieve the 35% capacity factor that IPL used in the modeling. *Id.* at 79. This makes no sense, given that IPL previously found that the Clean Line project will be able to deliver 50% capacity wind to IPL's service territory. *Id.* at 72-73. Moreover, while IPL is correct that the Clean Line project has not been completed, Clean Line anticipates completing the transmission project in 2019, well before 2025, when IPL modeled adding 200 MW of wind.

IPL did a thorough job of modeling various kinds of wind resources. However, IPL then seems to have discounted the very wind resources that IPL found to be most economical. The Commission should call upon IPL to monitor the development of the Clean Line transmission project in Indiana and ensure that IPL considers wind energy that can be delivered through the Clean Line project to IPL's service territory.

<u>Vectren</u>

1. *Vectren's declining savings projection does not reflect all economical DSM .*

As discussed above, Vectren incorporated DSM in two ways in its IRP – as a load forecast adjustment and as a resource that can be selected against supply-side options. The selected plan does not include additional DSM, so the base DSM forecast comprises the total amount of DSM in the IRP.

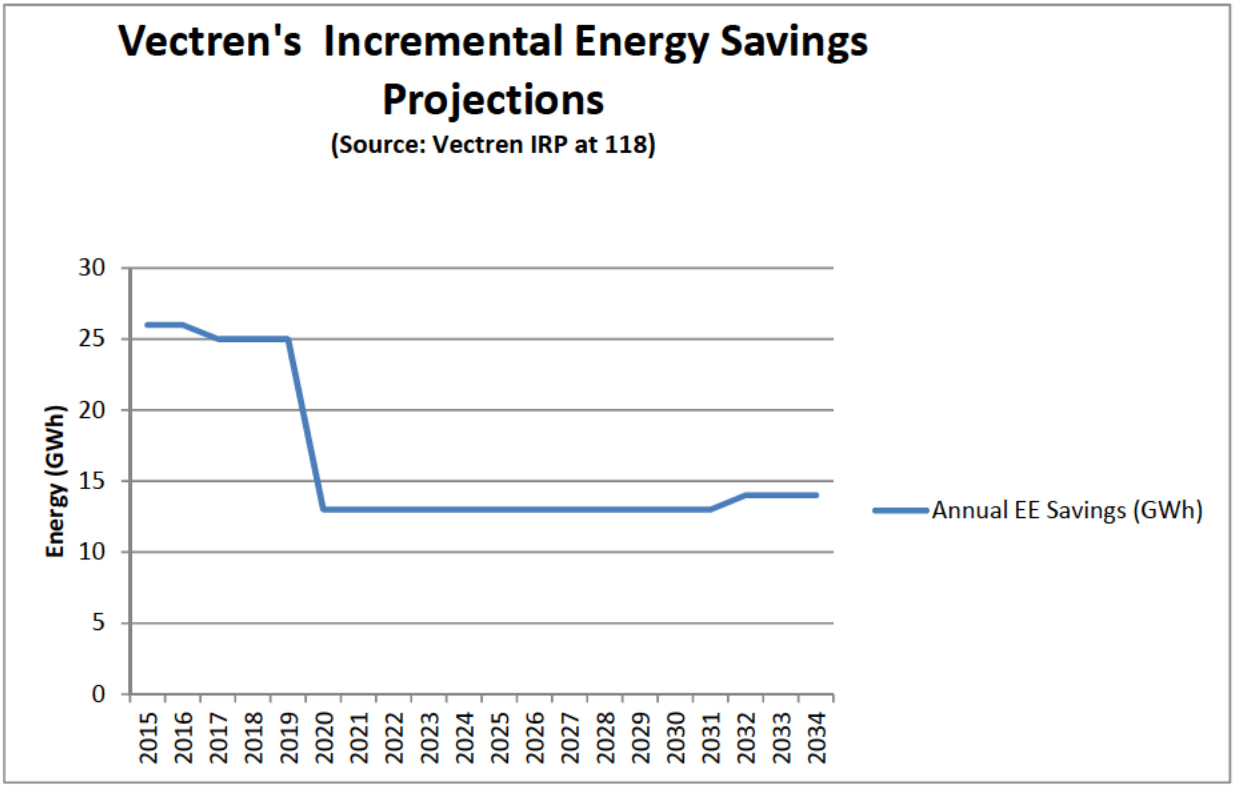
Vectren's IRP projects a sharp decline in the growth of energy efficiency resources over the planning period. Vectren projects 128 GWh of incremental savings over the next five years. Vectren IRP at 118 and Technical Appendix D, Vol. 1 at 8-5. This represents a 72% decrease from the Phase II savings goals and 61% from the potential study recommendations, as the below table shows.

Vectren Phase II Goal, Potential Study and IRP DSM Projections (Annual GWh)[44]

	Vectren's Phase II Goal	**Potential Study Recommended Savings**	**IRP DSM Projections**
2015	72	54	26
2016	82	60	26
2017	92	65	25
2018	102	70	25
2019	106	73	25
2015-2019 Total	455	322	127

After 2019, Vectren's annual savings drop substantially and then hold fairly steady throughout the planning period, as illustrated below. Vectren IRP at 118. The end result is a cumulative savings projection of roughly 8%, or 480 GWh, by 2034. *Id.* Vectren's declining and then flat annual savings and low cumulative total raises concerns, particularly given the low cost of Vectren's current portfolio, which has a lifetime cost of $0.03 per kWh. Vectren IRP at 154.

[44] Vectren IRP at 118 and Technical Appendix D, Vol. 1 at 8-5; MCR Performance Solutions, LLC, Indiana Demand Side Management Coordination Committee Core Portfolio Report, p. 11, IURC Cause No. 42693-S1 (June 19, 2013), available at https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631801a1dfc.



Vectren assumes that 70 - 80% of eligible large customers will opt out of DSM programs over the life of the plan. Industrial customers comprise Vectren's largest sector, accounting for 51% of load in 2011. IRP Appendix D, Vol.1, 3-1. Thus, high opt out rates leave a substantial amount of cost-effective efficiency on the table. Like IPL, Vectren should develop a strategy to achieve industrial efficiency savings and encourage customers to opt in. Vectren should also explore ways to incorporate the load impact from such opt out customers' own efficiency projects in its IRP.

NIPSCO

Similarly, NIPSCO has not demonstrated that it utilized all economical DSM. NIPSCO projects a 50% decrease in energy savings in 2015 as compared to last year. NIPSCO IRP at 46, 51. The Company's achievable potential is very low, 5.2% of baseline by 2030, and NIPSCO's plan appears to fall short even of this meager projection (although the amount of energy savings NIPSCO projects in its IRP is unclear). *Id.* at Appendix G, slide 4. In addition to improving and clarifying its modeling, NIPSCO should pursue all cost-effective energy efficiency opportunities.

D. 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)*).

IPL

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). IPL's IRP fails to accurately convey the PVRR results. The IRP presents a confusing array of results over different time periods and fails to explain what weight IPL accords to the modeling runs over different time horizons.

The IRP initially presents the ranking of plan PVRRs over the 2015-2064 period. IPL IRP at 66. Plan 2 has the lowest average PVRR across all scenarios. *Id.* And in four of six scenarios, Plan 2 is the least-cost plan. *Id.* at 74. Plan 2 represents IPL's existing portfolio, but adds 200 MW of wind energy in 2025. *Id.* at 70, 73. In all other respects except the addition of wind in 2025, Plans 1 and 2 are the same. *Id.*

But then when IPL begins the section summarizing the PVRR results, it presents the PVRR rankings over a different, shorter time horizon, from 2015-2034, which has a different PVRR rank order, in which Plan 1 is the cheapest plan. *Id.* at 78.

IPL should have clarified in the IRP the weight it gives to modeling over different time horizons, and should have clarified how it was dealing with any conflicting between model results over different time periods. As it stands now, the IRP presents the PVRR results over the shorter time period, 2015-2034, just before summarizing the reasons that IPL selects Plan 1 as its preferred plan. This gives an appearance of selectively choosing the model results that favor IPL's preferred plan, rather than transparently presenting the PVRR results. While the IRP Rule allows IPL discretion to pick a preferred plan that is not least-cost, IPL could have been more forthright that it was selecting a preferred plan that is more expensive than Plan 2 over 2015-2064.

Moreover, the reasons that IPL provided for not selecting Plan 2 as its preferred plan are unfounded. IPL states that it rejected Plan 2, which would add more wind energy than IPL's preferred plan, for two reasons: IPL modeled wind at capacity factors higher than are actually achieved at Indiana wind farms; and part of the benefit from wind is attributable to the Clean Power Plan, which is still uncertain. *Id.* at 79.

IPL's first reason is undermined by its own analysis of high-capacity wind that will be available once Clean Line's high-voltage transmission line is completed in approximately 2019. Clean Line anticipates being able to deliver wind energy into Indiana with a higher capacity factor than IPL modeled, meaning that the modeling underestimated how much could be saved through Plan 2. IPL's own modeling of the Clean Line project supports picking Plan 2.

IPL's second reason for rejecting Plan 2 is equally baseless. IPL claims that the Clean Power Plan is surrounded by uncertainty, but that is true of virtually all of the variables considered in a long-range planning exercise such as an IRP. All of the key variables in an IRP, including load forecasts, fuel prices, and market prices, are uncertain. A utility is expected to plan based on the best information available at the time of its decision, and the best information available today suggests that EPA will finalize the Clean Power Plan, and Indiana will have to submit a plan for reducing its carbon emission rate from power plants.

In addition to IPL's failure to clearly convey the PVRR results and the weight IPL accorded the results, the comments prepared by Synapse Energy & Economics on behalf of Sierra Club identify a deficiency in IPL's evaluation of carbon prices: IPL's base, low gas, and high gas scenarios apply carbon prices as a fixed cost rather than a variable cost. This is further confirmed by IPL's response to an informal discovery request. *See* IPL Response to CAC-Earthjustice Informal Data Request 09 (attached as Exhibit B) ("The modeling for this case applied EPA's shadow prices for Indiana as identified in the proposed Clean Power Plan (CPP) to IPL's coal unit emissions above the Indiana target emission rate commencing in 2020 as a fixed cost."). In other words, for these scenarios, IPL ran its dispatch model assuming no carbon price was in effect, and then only applied its assumed carbon price as an additional fee after the model had determined unit dispatch. As Synapse points out, this flaw in IPL's modeling biases its results in favor of a more carbon-intensive generating fleet that would be more vulnerable to the risk of future greenhouse gas regulations.

As Synapse also points out, IPL did not account for all of the costs and risks of future environmental regulations in its IRP modeling. Although IPL in its IRP estimates the potential costs of future environmental regulations, it did not actually incorporate those cost estimates into its IRP modeling. In particular, as IPL acknowledged in response to an informal data request, the company did not include in its IRP modeling the potential costs of the Coal Combustion Residuals ("CCR") rule, the Clean Water Act Effluent Limitation Guidelines ("ELG") rule, the one-hour sulfur dioxide ("SO2") National Ambient Air Quality Standard ("NAAQS"), or current or revised ozone NAAQS. *See* IPL Response to CAC-Earthjustice Informal Data Request 10 (attached as Exhibit C). The potential future costs and risks that IPL fails to evaluate in its IRP include the risk that a Selective Catalytic Reduction ("SCR") system will be required at IPL's Petersburg Unit 4 to comply with ozone NAAQS, installation of which would require a capital investment of over $146 million. *See* Cause No. 44540, Direct Testimony of Angelique Oliger, Attachment AO-6, page 3 of 7. IPL's failure to include the full range of potential future costs and risks of environmental compliance in its IRP modeling fatally biases its modeling results in favor of its existing coal-fired generating units, preventing the Commission from determining whether IPL's preferred resource portfolio represents an optimal balance of cost minimization with cost-effective risk and uncertainty reduction.

Vectren

1. *Vectren Repeatedly Fails to Mention its Modeling Results Showing that In the Vast Majority of Modeling Runs, Retiring FB Culley 2 is the Least-Cost Option.*

The IRP Rule requires each utility to demonstrate that it has balanced cost minimization with cost-effective risk and uncertainty reduction. 170 IAC 4-7-8(b)(7). To satisfy this requirement, a utility must accurately report the costs it obtains from its modeling, as a utility cannot properly balance costs against risks if the utility has inaccurately represented costs in the first place. Yet Vectren's IRP consistently mischaracterizes its economic modeling results.

Vectren states that "[t]he optimal resource plan is determined by evaluating all of the possible resource combinations and choosing the plan that minimizes the Net Present Value (NPV)." Vectren IRP at 186. Vectren modeled three plans over four scenarios. In three of the four scenarios, the plan in which FB Culley 2 is retired in 2020 is the least-cost plan. Vectren IRP at 202. Indeed, in the scenario most likely to occur—the base case—retiring FB Culley 2 would save ratepayers more than $26 million. *Id.* (showing that the revenue requirements are $26 million less in the "FB Culley 2 Unit Retirement Scenario" than in the "Base Scenario.").

While the IRP Rule does not dictate what 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. Yet rather than state that retiring FB Culley 2 has a revenue requirement $26 million lower than the next-best option, Vectren repeatedly fudges the numbers by saying that the results are "essentially the same." For example, this is how Vectren describes the modeling results in the section summarizing the modeling: "The cost of serving customers with existing resources, compared to retiring FB Culley 2 in 2020, were essentially the same under the low, base and high electric forecasts." Vectren IRP at 201.

Vectren repeats this language in its summaries of the sensitivity analyses. In three of the four scenarios, virtually all of the sensitivities indicated that retiring FB Culley 2 has the lowest revenue requirement, often reaching a $60 to $70 million benefit to retiring FB Culley 2. Remarkably, Vectren reports that the results for the Base Plan and the FB Culley 2 Unit Retirement Plan are "essentially the same." Vectren IRP at 205-207. That is a blatant misrepresentation of the data.

	Base Case Scenario[45]	**Low Demand Scenario[46]**	**High (Modeled) Demand Scenario[47]**	**High (Large Load) Demand Scenario[48]**
Total Number of Modeling Runs Reported	12	12	12	12
Number of Model Runs in Which Retiring Culley Unit 2 was Cheapest Option	11	11	10	0
Percent of Total Runs in Which Cheapest to Retire Culley 2	92%	92%	83%	0%

Conveniently, when Vectren summarizes the one scenario of four that supports its preferred plan, it notes that its preferred plan is "significantly less expensive" than the plan that features retiring Culley 2. Vectren IRP at 208.

Vectren goes on to say that its preferred plan is the base plan, rather than the plan in which FB Culley is retired in 2020. Under the IRP Rule, Vectren is free to choose its preferred portfolio. But the IRP Rule does not permit Vectren to let its selection of a preferred portfolio bias its presentation of the facts. Here, Vectren repeatedly misrepresents its economic modeling results by claiming that in three of four scenarios, the results are "essentially the same" whether FB Culley 2 is retired early or not—when the modeling actually shows benefits in the tens of millions of dollars to retiring FB Culley 2 early. Vectren's misrepresentation of its economic analysis violates a utility's obligation to fairly and accurately present the results of modeling designed to minimize costs. *See* 170 IAC 4-7-8(b)(7).

2. *Vectren's Modeling of Two High Demand Scenarios but Only One Low Demand Scenario Is at Odds with Industry Practice and its Declining Peak Demand and Energy Requirements.*

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[45] Vectren IRP at 205.

[46] *Id.* at 206.
[47] *Id.* at 207.
[48] *Id.* at 208.

One of the fundamental flaws in Vectren's highly flawed IRP is that Vectren stacked the deck in favor of its preferred plan by including two high demand scenarios but only one low demand scenario. It is standard industry practice to bound a base case with a high and low sensitivity, whether a utility is considering load forecasts or fuel prices. It is anomalous to include one low and two high sensitivities for a given variable such as load, as Vectren has done here. In fact, for every other sensitivity, from gas prices to capital costs, Vectren balanced a single high case with a single low case. Vectren IRP at 204.[49] Only when it came to demand did Vectren use two high cases but only one low case.

Vectren's inclusion of two high-load scenarios, but only one low-load scenario, *id.* at 202, flies in the face of the steady decline in Vectren's peak demand and energy requirements. The table below contains Vectren's actual peak demand and energy requirements over the last decade.

Year	**Peak Demand (MW)[50]**	**Energy (GWh)[51]**
2004	1,222	6,303
2005	1,316	6,508
2006	1,325	6,352
2007	1,341	6,527
2008	1,166	5,931
2009	1,143	5,958
2010	1,275	6,221
2011	1,221	6,244
2012	1,205	5,861
2013	1,102	5,822
Compound Annual Growth Rate (2004-2013)	**-1.15**	**-0.88%**

Moreover, Vectren forecasts that its decline in energy and peak demand requirements will continue for the foreseeable future. Vectren projects a -0.1% compound annual growth rate in demand and a -0.2% growth rate in annual energy requirements over the next 20 years. Vectren IRP at 68. The base case forecast projects a -0.2% annual growth in sales to large customers, so it makes even less sense to add a large customer, high-demand scenario on top of the regular high-demand scenario. *Id.* at 69. In the face of a 10-year decline in actual peak demand and energy requirements, and a base forecast showing continued decline in demand and energy requirements, it is wishful thinking at best for Vectren to include two high-demand scenarios but only one low-demand scenario.

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[49] Vectren modeled a "High Regulation Cost" sensitivity but not a "Low Regulation Cost" sensitivity. Vectren IRP at 204. However, the base case contains no costs for the 316(b), CCR, and ELG rule, as well as no costs for future NAAQS such as a lower ozone NAAQS. Thus, with respect to regulatory costs, the base case is the equivalent of a "Low Regulation Cost" option that balances the "High Regulation Cost" option.

[50] Vectren IRP at 94.

[51] *Id.* at 95.

In short, the IRP Rule requires Vectren to demonstrate that its preferred resource portfolio balances cost minimization with cost-effective risk and uncertainty reduction. *See* 170 IAC 4-7-8(b)(7). The requirement to demonstrate a balancing of costs against risk presupposes that the utility reasonably analyzes costs and risks in the first instance. Here, Vectren's use of two high-demand scenarios but only one low-demand scenario is unreasonable given that its actual peak demand and energy requirements have been decreasing over the last decade and are expected to continue declining over the next decade. By failing to use reasonable assumptions in its modeling of costs and risks, Vectren cannot demonstrate the balancing of costs and risks required by the IRP Rule. *See* 170 IAC 4-7-8(b)(7).

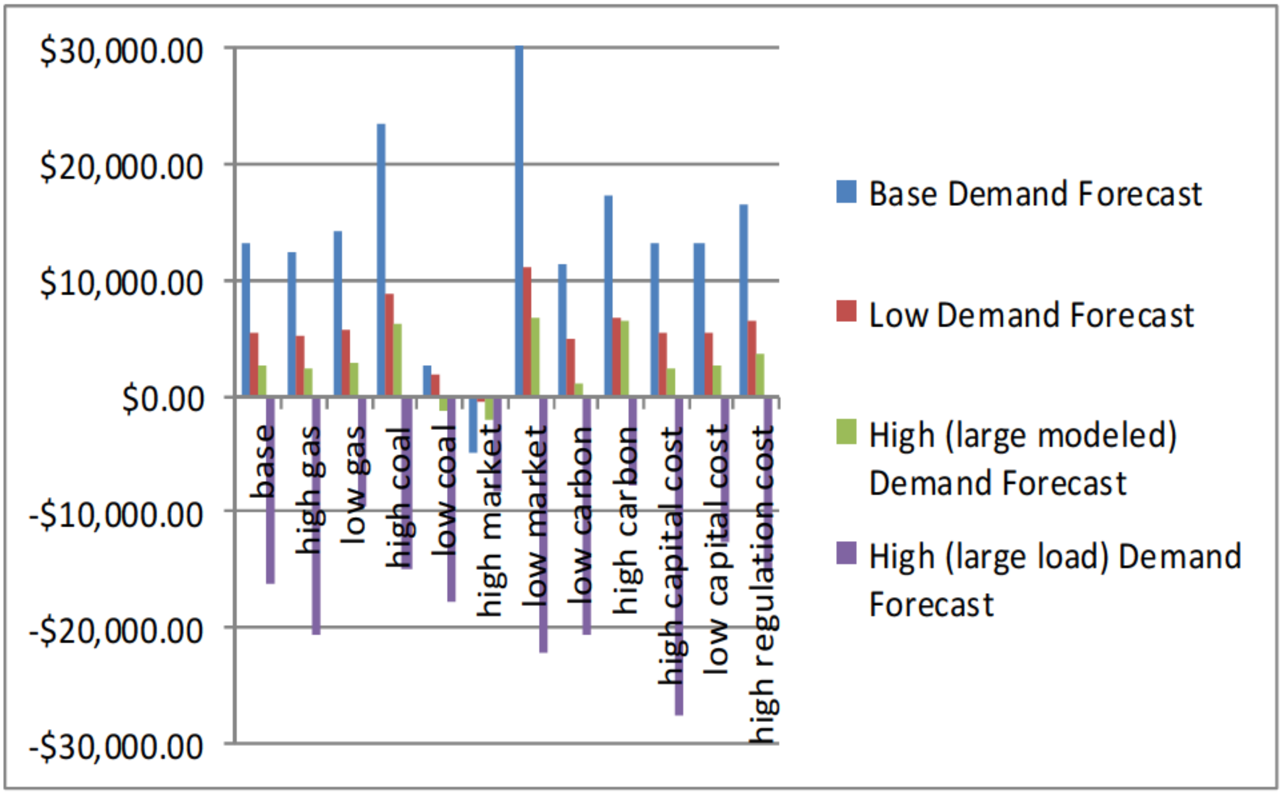
3. Vectren Ignored Standard Industry Practice by Treating Sensitivities as Equally Likely to Occur as the Base Case.

In addition to choosing unreasonable scenarios, Vectren erred by failing to follow the standard industry practice of weighting sensitivities less than the base case. By definition, a base case is a forecaster's view of the most likely outcome. *See, e.g.*, Cause No. 44540, Ayers Direct Testimony at 15 ("the selection of a base case implies that case is most probable based on what is known or should reasonably be known today."). Sensitivities bound the base case, and in general, sensitivities are less likely to occur than the base case. Yet Vectren inappropriately treats its low and high-demand scenarios as equally likely to occur as its base demand scenario.

Vectren bases its selection of its preferred resource portfolio in large part on comparing the sensitivity results across the four demand scenarios it modeled. Vectren IRP at 210. For each of the four scenarios, Vectren modeled a base case plus 11 sensitivities, which create 48 unique NPV results. Table 10-14 on page 210 presents the difference in the NPV between the base plan and the plan in which FB Culley 2 is retired in 2020.

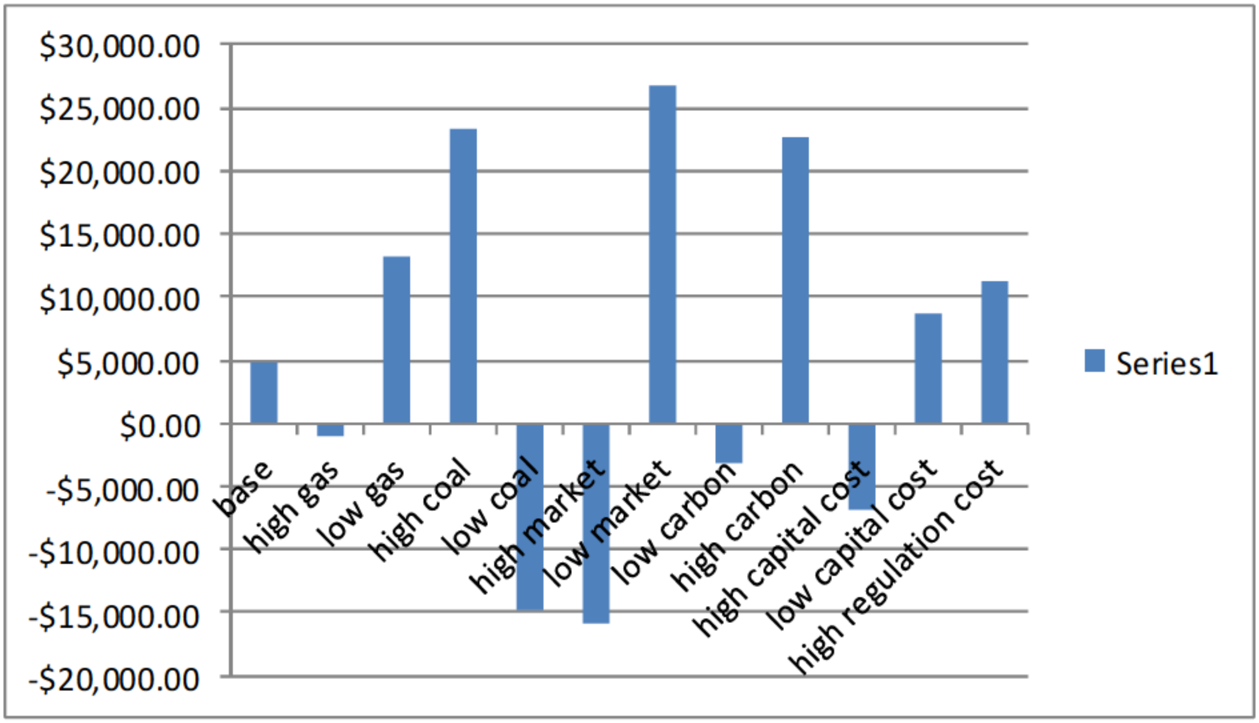
Table 10-14 is highly misleading because it implies that for each sensitivity, the low and high demand scenarios are as equally likely to occur as the base demand scenario. This is implausible. The definition of a base forecast is that it is the forecaster's view of the future that is most likely to occur. Vectren should have discounted the three alternative demand scenarios by the likelihood that they will occur. If Vectren had used an appropriate methodology, the data would look completely different.

Below, we provide an example of how the results would have changed if Vectren had discounted the value of each NPV by the probability of the scenario occurring. Since Vectren has not provided probabilities for each scenario and sensitivity, we used a conservative assumption that the base demand scenario is 50% likely to occur and each of the low and high demand scenarios is 16 and 2/3% likely to occur. Vectren could reasonably use different probability than the ones we use, but the alternative scenarios should be less likely to occur than the base scenario, absent some explanation from Vectren. The exact numbers below are not important, because they depend on the probability assigned to each scenario; instead, the relative magnitude of the values is important. In particular, the graph shows that the upside of retiring Culley 2 early is larger than the downside of retiring Culley 2 early in half of the sensitivities.



Vectren should have gone one step further and, for each sensitivity, compared the scenarios in which the NPV delta is positive—meaning retiring FB Culley 2 has a lower NPV—to the scenarios in which the NPV delta is negative—meaning retiring FB Culley 2 has a higher NPV. One way to do that is to calculate the expected value of the NPV delta by, for each sensitivity, multiplying the NPV delta by the assigned probability for the demand scenario in question, and then adding the four NPV deltas for each sensitivity. If the overall NPV delta is positive, it means that the benefit of retiring Culley 2 in certain scenarios exceeds the downside of retiring Culley 2 in other scenarios, after considering the probability of each scenario occurring. The graph below followed this methodology to calculate the expected value of the NPV delta, assuming that the base demand scenario is 50% likely to occur and each other demand scenario is 16 and 2/3% likely to occur.

As the figure below shows, in the majority of cases—including the base case—the expected value is positive, meaning that the benefit of retiring FB Culley 2 early is larger than the downside.



In short, the IRP rule does not dictate which portfolio Vectren must select as its preferred portfolio in its IRP. However, the IRP rule does require Vectren to demonstrate that the preferred resource portfolio balances cost minimization with cost-effective risk and uncertainty reduction, 170 IAC 4-7-8(b)(7), which presupposes that Vectren calculates the costs and revenue requirements of different portfolios in a reasonable way. While Vectren was right to use sensitivities to bound the base case, Vectren's IRP presents the sensitivities as equally likely to occur as the base case results. This is highly misleading. When the presentation is corrected to adjust the cost of plans in a sensitivity by the likelihood that the scenario will occur, the results change dramatically: in the majority of sensitivities, the overall risk is that not retiring FB Culley 2 in 2020 will lead to a larger NPV. In other words, in a majority of the 12 cases that Vectren modeled, it is more likely than not that retiring FB Culley 2 early will save ratepayers money by reducing the 20-Year NPV. Vectren's misleading presentation of its modeling results fails to disclose this key fact and therefore violates 170 IAC 4-7-8(b)(7).

NIPSCO

1. Carbon prices

NIPSCO's IRP evaluates only a narrow range of potential future carbon prices, containing no serious evaluation of the sensitivity of alternative resource portfolios to potential carbon prices. NIPSCO itself acknowledges that

> "[r]evised or additional [climate-related] laws and regulations could result in significant additional operating expense and restrictions on NIPSCO's facilities and increased compliance costs. Moreover, such costs could affect the continued economic viability of one or more of NIPSCO's facilities."

NIPSCO IRP at 95. Yet despite the magnitude of this potential risk, NIPSCO did not model any carbon price scenarios or sensitivities which evaluate the potential impact of the United States Environmental Protection Agency's ("EPA") proposed "Clean Power Plan" that is due to be finalized later this year. NIPSCO IRP at 96. NIPSCO's base case scenario, the assumptions of which are reflected in most of the sensitivities that NIPSCO models, assumes that the Clean Power Plan will not be implemented as proposed, but will instead be preempted by legislative or judicial intervention and ultimately replaced with a carbon price of $20/ton that takes effect in 2025. NIPSCO IRP at 96; *see also* NIPSCO Response to CAC/EJ Informal Request 2-017 (attached as Exhibit D). NIPSCO also evaluates a sensitivity to its base case scenario in which it assumes that no carbon price takes effect during the planning period. NIPSCO IRP at 120. The only other variation on carbon prices that NIPSCO models is in its Aggressive Environmental scenario, which incorporates the assumption that a carbon price of $20/ton takes effect in 2020, in tandem with assuming significantly increased costs from a range of other environmental regulations. NIPSCO IRP at 119.

While other commodity prices were varied according to high, low, and base case sensitivities, NIPSCO did not model any sensitivities that attempted to evaluate the impact of EPA's proposed Clean Power Plan on the company's alternative resource portfolios, nor did NIPSCO run any sensitivities evaluating any other carbon price assumption in isolation, i.e., without lumping it together with other increased commodity prices and increased costs as it did in the Aggressive Environmental Scenario. The sole explanation NIPSCO provides in its IRP filing for constraining its evaluation of carbon prices in this way is that its opinion is based on the possible future that it thinks is likely to occur in "the current economic and political environment." NIPSCO IRP at 95. NIPSCO fails to provide any specific analysis, however, to support its failure to include any evaluation at all in its IRP filing of the potential impact of the Clean Power Plan on its candidate resource portfolios and its generating fleet.

By evaluating only a narrow range of potential carbon prices, the NIPSCO IRP fails to account for the economic risks to its generating fleet posed by greenhouse gas regulation and the effect of those risks on the desirability of various resource portfolios. Accordingly, the NIPSCO IRP does not analyze "how candidate resource portfolios performed across a wide range of potential futures," 170 IAC 4-7-8(b)(7), and thus fails to live up to the requirements of the proposed IRP rule. The Commission Staff should, at a minimum, call on NIPSCO to evaluate the impact of the Clean Power Plan on its preferred and alternative resource portfolios in any future filings.

2. NAAQS compliance

NIPSCO acknowledges that compliance with one-hour sulfur dioxide National Ambient Air Quality Standards will be required at its coal-fired generating units during the planning period, but the Company fails to address in this IRP the possible future costs and risks to its preferred resource portfolio from implementation of that standard. Rather, the Company assumes – without providing any analysis in support of this assumption – that because its coal-fired generating units already have installed, or are in the process of installing, Flue Gas Desulfurization systems to control SO2 emissions, that no further capital investments in its generating units will be needed to comply with the one-hour standard. NIPSCO IRP at 96; *see also* NIPSCO Response to CAC/EJ Informal Request 2-018 (attached as Exhibit E). Similarly, NIPSCO assumes without providing supporting analysis that because its coal-fired generating units have installed Selective Catalytic Reduction systems to control nitrogen oxide ("NOx") emissions, that no further capital investments in its generating units will be needed to comply with current or revised ozone NAAQS or any future revision to the Cross-State Air Pollution Rule ("CSAPR") to implement a revised ozone NAAQS. NIPSCO IRP at 96; *see also* NIPSCO Response to CAC/EJ Informal Request 2-019 (attached as Exhibit F).

NIPSCO fails to support its assumption that no additional investments in its coal-fired generating units will be required to comply with either the one-hour SO2 NAAQS or current or revised ozone NAAQS. As other utilities such as IPL have found, upgrades or enhancements to pollution controls may be required to comply with new standards. NIPSCO's failure to fully address in its IRP filing the possible future costs and risks facing its generating fleet from NAAQS compliance falls short of the requirement in 170 IAC 4-7-8(b)(7) that NIPSCO "[d]emonstrate how the preferred resource portfolio balances cost minimization with cost-effective risk and uncertainty reduction, including . . . [through] [i]dentification and explanation of assumptions." The Commission Staff should call on NIPSCO to fully analyze the possible future costs and risks to its preferred resource portfolio from NAAQS compliance in any future filings.

E. Methodology and Documentation Requirement: Utilities must include a discussion of distributed generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting. (*170 IAC 4-7-4(b)(5)*).

IPL

Although solar costs are decreasing and IPL has experienced a large influx of early adoption of distributed solar generation, IPL believes that its service territory will see little growth in distributed generation ("DG"). IPL IRP at 78, 95. IPL should provide a more detailed discussion of DG in its IRP, explaining its position in light of current cost and technology trends.

Vectren

Recognizing the increased demand for distributed generation, Vectren modeled distributed solar PV in its IRP. Vectren IRP at 84. Vectren's distributed solar base forecast shows steady growth for the first half of the planning period (peaking at 2 MW annual growth in 2025), a sharp drop in 2026, and then gradual increase in growth through the end of the planning period. *Id.* at 85.

Vectren developed its forecast based on its historic net metering information and third-party data and assumptions. *Id.* at 84. With the exception of its capacity factor assumption, Vectren did not provide the third party data and assumptions on which it relied to develop its distributed solar forecast. Vectren refers to Navigant Consultant's solar capacity future growth rate assumptions for Indiana and, in a footnote, cites to "Navigant Consultant, 5/2/2014," Vectren IRP at 86. This is insufficient. References to a third party data source must include "the source title, author, publishing address, date, and page number of relevant data." 170 IAC 4-7-4(b)(2). Vectren should provide this information so that the Commission and interested parties can understand the growth rate assumptions on which Vectren relied. This is particularly important given Vectren's projected decrease in growth midway through the planning period despite the continued decline in price for residential and commercial PV systems.[52]

Vectren used a capacity factor of 38% to reflect the capacity value of distributed solar. Vectren IRP at 86. Vectren selected the 38% value because this is PJM's current class average capacity factor for solar. *Id.* at note 2. However, it is unclear that this assumption accurately reflects the capacity value of distributed solar in Vectren's territory. Vectren acknowledges that it may refine its assumption. *Id.* at 86. Vectren should explore ways to develop a capacity value of distributed solar generation that accurately reflects the installations in its service territory.[53]

[52] Depending on the size of the system, the reported prices of residential and commercial PV systems declined 6-7% each year, on average, from 1998-2013 and by 12-15% from 2012-2013. *See* David Feldmand *et al.*, Photovoltaic System Pricing Trends, slide 4, DOE SunShot (2014), available at http://www.nrel.gov/docs/fy14osti/62558.pdf.
[53] A 2014 PJM Renewable Integration Study calculated a range of effective load carrying capability (ELCC) values for residential PV solar between 57-58% in certain solar penetration scenarios. *See* GE Energy Consulting, PJM Renewable Integration Study: Executive Summary Report, Revision 05, p. 30 (Mar. 31, 2014), available at https://www.pjm.com/committees-and-groups/task-forces/irtf/pris.aspx.

F. Requirement—Analyze how existing facilities will conform to the plan to comply with existing and reasonably expected state and federal environmental regulations.

IPL

As noted above and described more fully in the comments prepared by Synapse Energy & Economics on behalf of Sierra Club, IPL's IRP fails to fully incorporate the potential future costs and risks of greenhouse gas regulations and other environmental regulations into its modeling of IPL's preferred resource portfolio. IPL's carbon price analysis in its base, low gas, and high gas scenarios treats carbon prices as fixed costs rather than variable costs, with the effect of allowing the company's dispatch model to choose continued operation of IPL's coal-fired generating units as if there were no carbon price and only adding in the costs of a carbon price as a fee on the back end. And IPL completely fails to model a range of potential future environmental compliance costs, despite having already developed compliance cost estimates for those potential regulations. The Commission Staff should call on IPL to correct these deficiencies in any future filings.

Vectren

Vectren's IRP fails to comply with the requirement 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. *See* 170 IAC 4-7-7(a)(2). Vectren merely describes pending, federal environmental rules, including the Clean Power Plan, which will regulate carbon emissions, and the Effluent Limitations Guidelines, which will regulate wastewater discharges. *See* Vectren IRP at 51-63. Similarly, Vectren merely notes the possible requirements of the now-final Coal Combustion Residuals rule, which regulates disposal of coal ash. *Id.* at 60-61. But the rule requires more; the rule requires an analysis of how facilities will comply with existing and reasonably expected environmental rules.

Both IPL and NIPSCO submitted such an analysis, covering the same environmental rules that Vectren's facilities face. IPL and NIPSCO analyzed how their existing units could comply with the ELG and CCR rule, among others, and developed corresponding compliance cost estimates (although, as noted above, IPL did not actually incorporate these compliance cost estimates into its IRP modeling). *See* IPL IRP at 40; NIPSCO IRP at 107, 120. IPL and NIPSCO have shown that such an analysis is feasible. By contrast, Vectren used compliance costs for then-pending rules such as the CCR rule, and still pending rules such as the ELG rule, only in the "High Regulation" sensitivity, which was one of 12 cases that Vectren modeled for each scenario. In 11 of 12 cases, Vectren assumed that the CCR rule, which is now final, and the ELG rule, which will be finalized this fall, will not increase capital or O&M costs at Vectren's units.

Vectren's failure to follow the IRP rule biases the results in favor of its existing units. Vectren's failure to analyze options for complying with reasonably expected environmental rules means that Vectren had no compliance cost estimates to use in the IRP modeling. Vectren's failure to comply with 170 IAC 4-7-7(a)(2) has important ramifications for the 2014 IRP. By not analyzing how existing units will conform to a plan to comply with reasonably expected federal environmental rules, Vectren relieved its existing units of tens or possibly hundreds of millions of dollars in capital costs, as well as fixed and variable O&M costs to operate the environmental controls. This biases the IRP results in favor of Vectren's existing units. The Commission Staff should call upon Vectren to include in future filings the estimated costs to comply with reasonably anticipated environmental rules.

NIPSCO

1. Carbon prices

As noted above, NIPSCO failed to include in its IRP filing any evaluation of the potential impact of EPA's proposed Clean Power Plan on its candidate resource plans or its generating fleet. NIPSCO's justification for this is its opinion that, in "the current economic and political environment," the Clean Power Plan is unlikely to be implemented as proposed due to the possibility of legislative or judicial intervention. NIPSCO IRP at 95; *see also* NIPSCO Response to CAC/EJ Informal Request 2-017 (attached as Exhibit D). This belief notwithstanding, NIPSCO cannot claim that the proposed Clean Power Plan is not a "reasonably expected" federal environmental regulation within the meaning of 170 IAC 4-7-7(a)(2) and that it is not reasonably possible that the Clean Power Plan will in fact be implemented in a form, and along a timeline, similar to that which EPA proposed last year. Commission Staff should call on NIPSCO to evaluate the impact of the Clean Power Plan on its preferred and alternative resource portfolios in any future filings.

2. NAAQS compliance

As noted above, NIPSCO assumes in its IRP that no further investments in its coal-fired generating units will be needed to comply either with the one-hour SO2 NAAQS or a new ozone NAAQS. NIPSCO provides no analysis in support of this assumption, however, which is contradicted by the recent experience of other utilities. For example, IPL has identified a need to invest in FGD enhancements at its Petersburg Station to comply with forthcoming stricter SO2 emissions limits due to Petersburg's contribution to SO2 NAAQS non-attainment. Commission Staff should call on NIPSCO, in its future filings, either to disclose any undisclosed analysis supporting its assumption that its coal-fired generating units do not face any potential risk of additional environmental compliance costs from either the one-hour SO2 NAAQS or a new ozone NAAQS, or if NIPSCO has not performed such an analysis, to conduct such an analysis as required by 170 IAC 4-7-7(a)(2).

Respectfully submitted,

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2014 IRP
Northern Indiana Public Service Company's
Objections and Responses to
Citizens Action Coalition/Earthjustice Informal Data Request Set No. 2

CAC/EJ Informal Request 2-009:
Please refer to page 104 of the IRP. a. Please identify and explain which existing resources were examined for retirement in the "Three Existing Resource Retirement Options." b. Please state whether the Strategist modeling was conducted to allow for selection of combinations of existing units to be retired, as opposed to retiring only a single unit at a time. c. Did NIPSCO evaluate retirement of any Schahfer units in the Strategist modeling? d. What does "market neutral" mean with respect to the 50 MW of future distributed generation that the Company considered?
Objections:
Response:
a. The three existing resources examined for retirement were Bailly Units 7 and 8, and Michigan City Unit 12. b. Yes, the Strategist modeling did allow for multiple retirements at once. c. No. d. "Market neutral" means the price of the generation resource was based on off-system market prices. The reason for making the distributed generation resource "market neutral" was to insure that the block of distributed generation was not favored by offering it at a price lower than market or penalized by offering it at a price higher than market. It was priced at market.

Data Request CAC-Earth Justice 09

Please refer to Confidential Attachment 5.1, page 15, which states that the "IPL-EPA $/ton were applied to IPL coal units as a fixed Portfolio cost ($/kW/yr) in the modeling."
a. What does IPL mean by "fixed Portfolio cost"?
b. Does IPL mean that its existing coal units were assigned fixed costs to reflect CO2 emissions rather than incorporating CO2 emissions costs into the variable costs of the units, as would be done for SO2 or NOx emissions prices?

Objection:

Response:

a. The modeling for this case applied EPA's shadow prices for Indiana as identified in the proposed Clean Power Plan (CPP) to IPL's coal unit emissions above the Indiana target emission rate commencing in 2020 as a fixed cost. These were applied as an annual aggregate fixed cost, taking into account emissions from all coal units depending on the resource plan.

b. Yes. For this scenario, it assumes there is not a tradable CO_2 market. The existing coal units were assigned fixed costs reflective of the EPA Shadow price. IPL anticipates completing additional modeling when the proposed CPP is finalized.

Data Request CAC-Earth Justice 10

Please refer to page 40 of the IRP.
a. For the estimated capital costs to comply with the CCR rule, please:
i. Identify the estimated costs per unit and per plant;
ii. Identify the control technologies, equipment, and projects that are assumed to be needed;
iii. Provide the workpapers used to generate the estimate capital costs.
b. For the estimated capital costs to comply with the ELG rule, please:
i. Identify the estimated costs per unit and per plant;
ii. Identify the control technologies, equipment, and projects that are assumed to be needed;
iii. Provide the workpapers used to generate the estimate capital costs.
c. For the estimated capital costs to comply with the 316(b)rule, please:
i. Identify the estimated costs per unit and per plant;
ii. Identify the control technologies, equipment, and projects that are assumed to be needed;
iii. Provide the workpapers used to generate the estimate capital costs.
d. For the estimated capital costs to comply with the SO2 NAAQS, please:
i. Identify the estimated costs per unit and per plant;
ii. Identify the control technologies, equipment, and projects that are assumed to be needed;
iii. Provide the workpapers used to generate the estimate capital costs.
e. For the estimated capital costs to comply with the ozone NAAQS, please:
i. Identify the estimated costs per unit and per plant;
ii. Identify the control technologies, equipment, and projects that are assumed to be needed;
iii. Provide the workpapers used to generate the estimate capital costs.

Objection:

Response:

While the table shown on page 40 of the IRP has a range of capital costs, IPL modeled the most probabilistic capital costs as shown below.

a. For the estimated capital costs to comply with the CCR rule, please:
    i. There are no capital costs associated with CCR in the IRP modeling.
    ii. N/A
    iii. Please refer to Confidential WP JMA-8 - NPDES_8A_WP1 – ENVIRO+TOTAL CAP+OM-NAAQS-Rev 8A_2WP3 (Confidential).xlsx submitted under Cause No. 44540.

b. For the estimated capital costs to comply with the ELG rule, please:
    i. There are no capital costs associated with ELG in the IRP modeling.
    ii. N/A

iii. Please refer to Confidential WP JMA-8 - NPDES_8A_WP1 – ENVIRO+TOTAL CAP+OM-NAAQS-Rev 8A_2WP3 (Confidential).xlsx submitted under Cause No. 44540.

c. For the estimated capital costs to comply with the 316(b) rule, please:

i. Identify the estimated costs per unit and per plant;

<table>
<tr><th>Capital Cost</th><th>2014</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>2021</th><th>2022</th><th>2023</th><th>Total</th><th>Total</th></tr>
<tr><td>Petersburg Unit 1</td><td>0</td><td>0</td><td>1,179,067</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>1,179,067</td><td rowspan="4">3,400,000</td></tr>
<tr><td>Petersburg Unit 2</td><td>0</td><td>0</td><td>2,220,933</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>2,220,933</td></tr>
<tr><td>Petersburg Unit 3</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>Petersburg Unit 4</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>Harding Street Unit 7</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>2,700,000</td><td>0</td><td>0</td><td>0</td><td>2,700,000</td><td>2,700,000</td></tr>
<tr><td>Total</td><td>0</td><td>0</td><td>3,400,000</td><td>0</td><td>0</td><td>0</td><td>2,700,000</td><td>0</td><td>0</td><td>0</td><td>6,100,000</td><td>6,100,000</td></tr>
</table>

These capital costs reflect the Low Case capital cost for 316(b) as shown in Attachment AO-6 Summary of anticipated Environmental Regulations and Requirements and associated cost.pdf Page 2 of 7 under Cause No. 44540.

ii. The capital cost displayed in the table above assume modified traveling screens and fish handling return systems will be needed to comply with 316(b).

iii. Please refer to Confidential WP JMA-8 - NPDES_8A_WP1 – ENVIRO+TOTAL CAP+OM-NAAQS-Rev 8A_2WP3 (Confidential).xlsx submitted under Cause No. 44540.

d. For the estimated capital costs to comply with the SO2 NAAQS, please:

i. There are no capital costs associated with SO2 NAAQS in the IRP modeling.

ii. N/A

iii. Please refer to Confidential WP JMA-8 - NPDES_8A_WP1 – ENVIRO+TOTAL CAP+OM-NAAQS-Rev 8A_2WP3 (Confidential).xlsx submitted under Cause No. 44540.

e. For the estimated capital costs to comply with the ozone NAAQS, please:

i. There are no capital costs associated with ozone NAAQS in the IRP modeling.

ii. N/A

iii. Please refer to Confidential WP JMA-8 - NPDES_8A_WP1 – ENVIRO+TOTAL CAP+OM-NAAQS-Rev 8A_2WP3 (Confidential).xlsx submitted under Cause No. 44540.

2014 IRP
Northern Indiana Public Service Company's
Objections and Responses to
Citizens Action Coalition/Earthjustice Informal Data Request Set No. 2

CAC/EJ Informal Request 2-017:
Please refer to page 96 of the IRP, where it states that "NIPSCO is estimating that a price on carbon will not be established prior to 2025 due to the current economic and political environment, in addition to the time required for a widespread program to be developed and implemented." Please explain how this assumption as to the timing of implementation of greenhouse gas regulation is consistent with the timing of implementation of U.S. EPA's proposed Clean Power Plan.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that such Request seeks information that is confidential, proprietary and/or trade secret information.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO's assumption regarding the timing of a carbon cost is consistent with the CO2 emission price assumptions, used to develop NIPSCO's IRP, that were provided by PIRA Energy Group (PIRA). PIRA's CO2 emission price assessments* consider the expected legal and political challenges facing the United States Environmental Protection Agency's proposed Clean Power Plan (CPP), and assumes, rather than CPP implementation, the United States Congress would ultimately adopt federal carbon legislation to achieve carbon emissions reductions. Analysis conducted for NIPSCO's IRP also includes various carbon cost and timing sensitivities; please see NIPSCO's IRP Section 9 pages 119-120. *North American GHG Quarterly Update (09/19/2014), Long Term Power Price Forecast (05/22/2014)

2014 IRP
Northern Indiana Public Service Company's
Objections and Responses to
Citizens Action Coalition/Earthjustice Informal Data Request Set No. 2

CAC/EJ Informal Request 2-018:
Has NIPSCO prepared or caused to be prepared any analyses of how implementation of U.S. EPA's one-hour sulfur dioxide National Ambient Air Quality Standard may affect its existing generating units? If so, please produce all such analyses.
Objections:
Response:
In 2010, the EPA finalized a more stringent 1-hour National Ambient Air Quality Standard for sulfur dioxide ("SO2"). NIPSCO does not anticipate significant impact from the implementation of this standard. Each of the NIPSCO coal-fired generating units except for Michigan City Unit 12 are equipped with flue gas desulfurization ("FGD") emission controls. Unit 12's FGD is currently under construction.

2014 IRP
Northern Indiana Public Service Company's
Objections and Responses to
Citizens Action Coalition/Earthjustice Informal Data Request Set No. 2

CAC/EJ Informal Request 2-019:
Has NIPSCO prepared or caused to be prepared any analyses of how issuance and implementation of a more stringent ozone National Ambient Air Quality Standard by U.S. EPA may affect its existing generating units? If so, please produce all such analyses.
Objections:
Response:
The Environmental Protection Agency has proposed a more stringent ozone National Ambient Air Quality Standard ("NAAQS") of 65-70 parts per billion. NIPSCO has not formally analyzed the impact of this proposed NAAQS on NIPSCO generating units. However, NIPSCO believes that, if a more stringent standard were imposed, ozone nonattainment would likely expand in Indiana. The Indiana Department of Environmental Management may then require Reasonably Available Control Technology for existing generating units. NIPSCO generating units are equipped with control technology for emissions of nitrogen oxides (NOx), an ozone precursor. At this time NIPSCO does not anticipate additional NOx controls will be required on its units.