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Comments on Indianapolis Power & Light Company's 2014 Integrated Resource Plan

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1. INTRODUCTION

Synapse Energy Economics, Inc. ("Synapse"), was retained by Sierra Club to review Indianapolis Power & Light Company's (IPL) 2014 IRP, provide comments and feedback to IPL throughout the stakeholder process, attend stakeholder meetings and review the final IRP.

IPL, as with many other utilities, has been subject to low load growth, low gas prices, increasing public and regulatory urgency to reduce emissions of carbon dioxide, and existing and emerging environmental regulations. Effectively planning for retirements in a transparent and open fashion is critical to achieving a sustainable and cost-effective resource portfolio that strikes an appropriate balance between cost-minimization and risk reduction.

The first section of our comments address the scenario structure and resource choice methodology used in the IRP. IPL has the resources and capability to perform rigorous planning, modeling, and analysis, and offer appropriate resources to ensure comprehensive planning. Rather than using the planning tools available to it, however, IPL appears to have developed arbitrary futures for its fleet that provide little insight into the true economics of each of its generating units by lacking an analysis of the units on an individual basis. The modeling also mistreats revenue that the Company acquires through selling generation in excess of its system requirements (i.e. off-system sales).

IPL has acknowledged that it is not immune to increasing pressures on coal generation. However, as we discuss in the second section of our comments, other elements of IPL's fleet remain vulnerable as a result of IPL's insufficient treatment of costs from carbon regulation, competing natural gas prices, and omission of costs related to upcoming environmental regulations affecting its coal units.

The final section of our comments addresses the Company's consideration of demand-side management resources.

2. RESOURCE PLANNING AND MODELING

The Company's planning methodology has evolved slightly during the stakeholder process, largely in response to stakeholder comments--including from the Sierra Club. However, IPL's modeling approach in the 2014 IRP continues to be limited in both its structure and assumptions. This section summarizes problems with the Company's chosen plan, as well as with the Company's treatment of scenarios, resource choices, and treatment of off-system sales. Subsequent sections address key flaws in the underlying assumptions.

2.1. Summary of Modeling and Results

As part of the IRP process, the Company and its consultant, Ventyx, explored resource options through a two-step modeling process: 1) capacity expansion modeling and 2) an evaluation of five resource plans

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based on capacity expansion modeling results. Ventyx provided assumptions for energy, capacity, and natural gas prices, and IPL developed carbon prices and load forecasts. Ventyx then performed capacity expansion modeling to determine the Company's portfolio, including new builds, given certain future scenarios over the 20-year period. These scenarios included: Base, High Gas, Low Gas, High Load, Low Load, High Environmental, Environmental, and Low Environmental--shown in Figure 1 below. We discuss further how the carbon price was not applied properly in scenarios 1 through 5, disproportionately favoring the generation of coal in these scenarios.

Scenario No	Scenario Name	Gas/Market Price	CO_2 Price	Load Forecast
1	Base	Ventyx Base	IPL-EPA Shadow price starting 2020	Base
2	High Load	Ventyx Base	IPL-EPA Shadow price starting 2020	High
3	Low Load	Ventyx Base	IPL-EPA Shadow price starting 2020	Low
4	High Gas	Ventyx High	IPL-EPA Shadow price starting 2020	Base
5	Low Gas	Ventyx Low	IPL-EPA Shadow price starting 2020	Base
6	High Environmental	Ventyx Environmental	Waxman-Markey proxy Ventyx Fall 2013 price starting 2025	Base
7	Environmental	Ventyx Mass Cap	Mass Cap ICF price starting 2020	Base
8	Low Environmental	Ventyx Base	None	Base

Figure 1: IPL's Modeling Scenarios (Figure 4.8 in IRP)

The capacity expansion modeling results (Figure 2) showed that it was economic to retire Petersburg units 1, 2, and 4 under the Company's Low Gas scenario or retire Petersburg unit 1 in 2024 in the Environmental scenario. In most scenarios, no capacity is retired or built until 2030.

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YEAR	Base	High Gas	Low Gas	High Load	Low Load	High Environ-mental	Environ-mental	Low Environ-mental
2015	Market 200 MW	Market 200 MW	Market 200 MW	Market 200 MW	Market 200 MW	Market 200 MW	Market 200 MW	Market 200 MW
2016	Market 450 MW	Market 450 MW	Market 450 MW	Market 500 MW	Market 450 MW	Market 450 MW	Market 450 MW	Market 450 MW
2017	671 MW EV CCGT	671 MW EV CCGT	671 MW EV CCGT	671 MW EV CCGT	671 MW EV CCGT	671 MW EV CCGT	671 MW EV CCGT	671 MW EV CCGT
2018-2019								
2020			Retire Pete 1,2, and 4 CC 200 MW					
2021			CC 800 MW Market 100 MW					
2022			CC 200 MW					
2023								
2024				Market 50 MW		Retire Pete 1		
2025				Market 50 MW		CC 200 MW		
2026				Market 50 MW				
2027				CC 200 MW				
2028						Wind 100 MW		
2029						Wind 150 MW		
2030	Market 50 MW	Wind 100 MW				Wind 100 MW	Market 50 MW	Market 50 MW
2031	Retire HSS 5 and 6 CC 200 MW Market 50 MW	Retire HSS 5 and 6 CC 200 MW Wind 150 MW	Retire HSS 5 and 6 CC 200 MW	Retire HSS 5 and 6 CC 200 MW	Retire HSS 5 and 6 CC 200 MW	Retire HSS 5 and 6 CC 200 MW Market 50 MW Wind 50 MW	Retire HSS 5 and 6 CC 200 MW Market 50 MW	Retire HSS 5 and 6 CC 200 MW Market 50 MW
2032	Market 50 MW	Wind 100 MW				Market 50 MW	Market 50 MW	Market 50 MW
2033	Retire Pete 1 CC 200 MW Market 100 MW	Retire Pete 1 CC 200 MW Wind 50 MW Market 50 MW	Market 50 MW	Retire Pete 1 CC 200 MW Market 50 MW	Retire Pete 1 CC 200 MW	Market 50 MW	Retire Pete 1 CC 200 MW Market 100 MW	Retire Pete 1 CC 200 MW Market 100 MW
2034	Retire HSS 7 CC 400 MW Market 150 MW	Retire HSS 7 CC 400 MW Market 100 MW	Retire HSS 7 CC 400 MW Market 100 MW	Retire HSS 7 CC 400 MW Market 50 MW	Retire HSS 7 CT 180 MW CC 200 MW Market 50 MW	Retire HSS 7 CC 400 MW Market 100 MW	Retire HSS 7 CC 400 MW Market 150 MW	Retire HSS 7 CC 400 MW Market 150 MW

Figure 2: Ventyx Capacity Expansion Results (Figure 4.10 in IRP)

The capacity expansion results were used by IPL to develop five plans for further evaluation—shown in Figure 3. Plans 1 and 2 fix IPL's existing capacity in-place, while Plans 3 through 5 assume that Petersburg units 1 and 2 are retired and replaced with natural gas units or combinations of natural gas and wind. IPL claims these plans were "created to represent the results of the capacity expansion

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model."[1] However, unlike in the capacity expansion plan modeling, the unit retirements are fixed in each of the five plans chosen by IPL. Put simply, IPL chose to either retire both or not retire both Petersburg units 1 and 2 in each of these five plans, rather than letting the model run without IPL's fixed treatment of these resources. As we will discuss later, this structure does not allow for viewing each unit's economic viability. For instance, if retiring Petersburg unit 1 alone were the more economic option for IPL, we would never know since this modeling construct does not allow for that possibility.

YEAR	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5
2024			Retire Pete 1 & 2	Retire Pete 1 & 2	Retire Pete 1 & 2
2025		Wind 200 MW	CC 600 MW	CT 550 MW & Wind 500 MW	CC 600 MW & Wind 200 MW
2026					
2027					
2028					
2029					
2030					
2031	CC 200 MW	CC 200 MW	CC 200 MW	CC 200 MW	CC 200 MW
2032					
2033	CC 200 MW	CC 200 MW			
2034	CC 400 MW	CC 400 MW	CC 400 MW	CC 400 MW	CC 400 MW

Figure 3: IPL's Five Resource Plans (Figure 4.11 in IRP)

IPL modeled the total costs of its fleet under each of the five plans for several, limited scenarios: Base, High Gas, Low Gas, High Environmental, Environmental, and Low Environmental. These are similar to the scenarios used in the capacity expansion modeling except they do not include Low Load or High Load scenarios. IPL also modeled these plans over a 50-year period instead of a 20-year period. Table 1 shows the results by scenario as ranked by lowest cost (1) to highest cost (5) for the five plans -- with the lowest cost plan in each scenario shaded in grey.

[1] IPL 2014 IRP, p. 58

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Table 1: Ranking of IPL's Lowest Cost Plan by Scenario[2]

	Base	High Gas	Low Gas	High Env.	Env.	Low Env.
Plan 1 (IPL's preferred plan)	2	2	3	5	2	2
Plan 2	1	1	4	4	1	1
Plan 3	4	5	1	3	4	4
Plan 4	5	4	5	2	5	5
Plan 5	3	3	2	1	3	3

Despite it not being the lowest cost plan in any scenario, IPL chose Plan 1 as its "preferred portfolio". Plan 2 was the lowest cost in most scenarios but was not chosen since IPL claimed that the inclusion of wind in that plan was "based upon the belief that transmission capabilities will be improved to resolve the current conditions."[3] We discuss further that this conclusion was too easily dismissive of new wind resources.

2.2. IPL's Preferred Portfolio ("Plan 1") is Based on Flawed Modeling

There are several issues with IPL's modeling methodology and selection of Plan 1, including:

- **The structure of the scenarios does not allow for unit-by-unit evaluation.**
- **The Company dismisses Plan 2 because of uncertainty surrounding wind, even though this is the lowest cost plan under most scenarios**, as shown in Table 1.
- **The Company continues to model off-system sales as if 100% flows directly to ratepayers whereas this is not the case, in reality.**
- **In Section 3, I will address flaws in underlying assumptions including that:**
    - **The Company's carbon price is not applied properly in most scenarios**. As a result, the Company's analysis biases the results towards continued operation and investment in its coal fleet.
    - **Future environmental spending is not all included in IPL's modeling**. The Company has provided a range of estimates for compliance with upcoming environmental regulations such as Coal Combustion Residuals (CCR), Effluent Limitation Guidelines (ELG), Cooling Water Intake (Section 316(b) of the Clean Water Act), Cross-State Air Pollution Rule (CSAPR), and National Ambient Air

[2] IPL 2014 IRP, p. 66-71
[3] 2014 IRP, p. 79

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Quality Standards (NAAQS). However, it appears that most or all of these future costs were not included in the IRP modeling.

Structure of modeling scenarios does not allow for unit-by-unit evaluation or combinations of risks

After the capacity expansion modeling, the Company evaluated five portfolios (Plans 1 through 5) under multiple scenarios of natural gas and carbon prices. This analysis was limited to simply testing five portfolios against different commodity price variations. By limiting the build-out to the review of exactly five worlds, the IRP lost the opportunity to review how different explicit variable changes impact the choices of portfolio and denied regulators and stakeholders the opportunity to assess how Company assumptions impact decisions. Moreover, IPL ran each scenario in isolation of the others, rather than in combination. By only changing gas and carbon costs, individually, it is impossible to see the results with combinations of risks (e.g. High Gas/High Environmental).

The Company claims that in developing the five portfolios (Plans 1 through 5) it "limited the potential of earlier retirements to the two Petersburg units because that is what the capacity expansion results indicated as the most economic and in order to maintain a balance in fuel mix and portfolio diversity."[4] However, there is no scenario in the capacity expansion results in which <u>only</u> Petersburg units 1 and 2 are retired (see Figure 2). In the Low Gas scenario, Petersburg units 1, 2, <u>and 4</u> are retired while in the High Environmental scenario, <u>only</u> Petersburg unit 1 is retired.

The capacity expansion modeling allowed for unit-by-unit retirements. The subsequent selection and modeling of the five plans, however, fixed retirements and building of new generation in-place. A more rigorous analysis would have allowed the economic viability of units or plants to fluctuate with important variables, rather than holding them fixed. The Company has the capability to evaluate decisions on this basis, but the Company neglected to do so in the IRP outside of the capacity expansion modeling—which only provided the basis for selecting the five fixed portfolios. While the recent CPCN filing (Cause Number 44540) does perform unit-by-unit valuation studies, the IRP fails to provide a mechanism by which regulators or stakeholders can review the economic viability of individual units without performing post-hoc analyses.[5] While the Company is taking steps towards improving the structural framework for their analyses in the docketed CPCN case, this level of rigor should also apply to this IRP proceeding.

An entire resource type is dismissed without adequate justification

As shown in Table 1, the lowest cost portfolio in most scenarios modeled by the Company is Plan 2. Plan 2 is the same as Plan 1 but with an additional 200 MW of wind added in 2025. Yet despite Plan 2 being lower cost, IPL selects Plan 1 as its "preferred portfolio." IPL's justification for not pursuing additional wind is deficient and highly inadequate. The Company modeled new wind using a 35% capacity factor

[4] IPL 2014 IRP, p.58

[5] *See* IURC Cause No. 44540, Direct Testimony of James Ayers, Figures 10-21.

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and assuming a Locational Marginal Price (LMP) equal to the MISO Indiana price. In IPL's justification for not pursuing this option, the Company stated that these assumptions were "based upon the belief that transmission capabilities will be improved to resolve the current conditions" and that they were "improvements from the actual characteristics of Hoosier and Lakefield Wind Farms."[6] However, the Hoosier and Lakefield facilities were built in 2009 and 2010, respectively. Since then, technologies have improved markedly, leading to higher wind capacity factors. In addition, MISO is taking significant steps in facilitating more wind generation on the grid, in part through the MVP (Multi-Value Project) process.[7] Given recent improvements in wind performance and pending transmission projects, the Company should not dismiss the option of additional wind and should be required to defend or fix its flat-out dismissal of an entire resource.

The Company has also focused on building its own wind rather than procuring wind through a power purchase agreement (PPA). The most recent wind technologies report by the U.S. Department of Energy shows that new wind PPAs have reached "all-time lows" costing "around $25/MWh nationwide."[8] Thus a low-cost wind PPA could provide an attractive hedge against the MISO energy market. A wind PPA would also provide protection from risks of fuel price volatility and environmental compliance costs associated with fossil fuel generation.

The Company conducted sensitivities for wind characteristics, including a lower capacity factor (25%), complementary batteries for energy storage, lower energy revenue, and access to lower cost wind PPAs through completion of the Clean Line transmission project (assuming 50% capacity factor wind).[9] Not surprisingly, the Company estimates that the low cost wind PPA through the Clean Line would reduce costs for Plan 2--which was already lower than Plan 1, the selected portfolio. However, the Company merely concludes that it will "monitor the progression of transmission capability and technology improvements in the wind industry"[10] and then promptly dismisses Plan 2.

Given that the Company's original Plan 2 was the lowest cost plan--even with conservative assumptions for wind performance--it should not dismiss the addition of an entire resource type based on such vague and insufficient reasoning. The conclusion from this IRP is that IPL is not proactively pursuing wind but will simply monitor the continuing progress of wind energy from the sidelines. Put simply, IPL's decision to exclude wind from its analysis for the entirety of the planning horizon is unreasonable and does not balance cost minimization with cost-effective risk reduction.

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[6] IPL 2014 IRP, p.79

[7] *See* MISO Transmission Expansion Plan 2014 (MTEP14), p.53. Available here: https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP14/MTEP14%20Full%20Report.pdf

[8] U.S. Department of Energy (DOE), 2013 Wind Technologies Report, p. ix.

[9] *See*: http://www.cleanlineenergy.com/projects

[10] IPL 2014 IRP, p.73

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Treatment of off-system sales is inconsistent with evidence filed in IPL's general rate case

Sales of energy and capacity over and above what is required to meet system requirements are referred to as "off-system sales". The net revenue generated from these sales can be credited back to ratepayers through a reduction in revenue requirements, passed through to shareholders as additional profit, or a mix of the two. It is important that the handling of this net revenue be treated in modeling as it is in reality.

IPL has consistently modeled off-system sales as if 100% of net revenues were passed through ratepayers.[11] However, it has been unclear how these net revenues were handled in the past due to the lack of a rate case filing – until recently. IPL has filed for a rate case with the IURC (Cause Number 44576) and asked for approval of a sharing provision for 50% of off-system sales to pass through to ratepayers and 50% to pass through to shareholders.[12] IPL should conduct new modeling to reflect this development. As it stands, the analysis assumes that 100% of net revenues from off-system sales are credited to ratepayers, which is inconsistent with IPL's new practices. Without adjusting for this new provision, the IRP modeling will disproportionately favor portfolios that generate more energy or capacity than required. As it stands, the IRP modeling assumes that ratepayers will receive <u>twice</u> the net revenues than they would actually receive; this is clearly wrong.

Recommendations:

1. While the Company attempts to evaluate carbon, natural gas, load and capital cost risks, it does so only against fixed portfolios. The Company should instead evaluate the impact of key variables and combinations of variables on the economics of each unit in order to consider "a wide range of potential futures." 170 IAC 4-7-8(b)(7)(C).

2. The Company should adequately assess the "robustness" of wind generation, especially through low cost PPAs (170 IAC 4-7-8(b)(7)(E)), rather than dismissing it as a "candidate resource portfolio[]" that performed well "across a wide range of potential futures." 170 IAC 4-7-8(b)(7)(C).

3. The Company should treat off-system sales consistently in both its IRP planning analysis and in ratemaking. Ratepayers should not be credited with revenue that will not materialize. Since the Company is proposing a new sharing provision in its general rate case filing, this should be applied in its IRP modeling to ensure consistency.

[11] See Direct Testimony of Tyler Comings, Cause No. 44339, pp. 17-18
[12] IPL Petition for Rate Increase and Verified Relief, Cause No. 44576, p.10.

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3. Scenario Input Assumptions

The Company's scenarios are based on varying carbon and natural gas prices. The Company is also subject to environmental compliance costs for other future regulations. Below, we describe issues with each of these key inputs in IPL's IRP modeling, including:

- **The Company's carbon prices in the Base, Low Gas and High Gas cases are not applied to the cost to dispatch coal units, which would falsely favor coal generation in a carbon-regulated future.**
- **The Company's natural gas prices are outdated and likely [redacted].**
- **The Company has not sufficiently modeled costs of compliance with future environmental regulations.**

3.1. Costs of carbon dioxide emissions

In the IRP, the Company chooses between five plans viewed through scenarios with varying natural gas and carbon prices developed by Ventyx in fall of 2013. IPL has responded to stakeholders' concerns by including carbon costs in more scenarios. However, the Base, Low Gas and High Gas scenarios only apply carbon costs as a fixed cost rather than a variable cost by assigning a zero dollar variable cost for carbon regulations in these three scenarios.[13] A fixed price applied "after the fact" would not affect the dispatch of coal units – as if carbon regulations would have no effect on their operating characteristics. Whereas a properly applied variable carbon cost greater than zero would favor dispatch of less carbon-intensive resources over coal generation than what the Company's Base, Low Gas and High Gas assumes. It appears that for the other positive carbon price scenarios (Environmental and High Environmental), IPL applies the price as a variable cost for every ton of carbon emitted. However, the Base, Low Gas and High Gas scenarios implicitly and unrealistically assume that carbon regulation would have no effect on how the Company's coal units would operate.

The inclusion of a carbon cost in utility resource modeling is critical to protecting IPL and its ratepayers from exposure to the costs of greenhouse gas regulations. If IPL fails to properly apply a reasonable carbon price forecast in its base case, the result will be a carbon-intensive fleet more vulnerable to escalating costs under the Clean Air Act's Section 111(d) regulation or any other carbon legislation and/or regulations. Almost all of the large investor-owned utilities reviewed by Synapse in both docketed proceedings and IRPs include a variable carbon price in their planning.[14] This includes Duke Energy Indiana and Indiana-Michigan, which assume a variable carbon price in their most recent IRP base cases.[15]

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[13] IPL 2014 IRP, p.51.

[14] Luckow, P., et. al. 2013 Carbon Dioxide Price Forecast. (2013).

[15] Duke Energy Indiana 2013 IRP, p. 10. Available here:

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3.2. Natural gas price forecasts

The natural gas price forecasts are one of the most important inputs to IRP modeling. These should reflect up-to-date expectations and provide a reasonable range of outcomes in the future. As with the carbon price forecasts discussed above, IPL relied on Ventyx's forecasts for natural gas, energy and capacity prices. All forecasts provided by Ventyx were from the fall of 2013, even though we are now approaching the spring of 2015.[16] Not surprisingly, since the fall of 2013, expectations have changed. The Ventyx natural gas price forecasts are outdated and [redacted], especially in the short-term. This concern also applies to energy market prices since they are highly correlated with natural gas prices.

Ventyx's four natural gas price forecasts are shown below in Figure 4. We have also included recent NYMEX futures for natural gas for 2015 and 2016—which show the market outlook for natural gas as of January 29, 2015. Interestingly, Ventyx's low gas price forecast [redacted] NYMEX future prices. In fact, the NYMEX outlook for the rest of 2015 is [redacted] the Ventyx low forecast for 2015. The Ventyx high gas price forecast is clearly wrong since it assumes [redacted] which is not the case. In early January 2015, gas prices at Henry Hub are around $3/MMBtu; throughout 2014, prices hovered at around $3-$4.50/MMBtu.[17]

In sum, the Ventyx natural gas price forecasts are [redacted] in the short-term and should be re-evaluated for the long-term. In general, inflated natural gas prices bias the results against natural gas generation and in favor of coal generation. Natural gas price forecasts are too critical to the modeling results to be [redacted] and outdated.

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http://www.duke-energy.com/pdfs/Indiana_Public_IRP.PDF
Indiana-Michigan 2013 IRP, p. ES-4. Available here:
http://www.in.gov/iurc/files/2013_Indiana_Michigan_Power_Co_-_IRP_Report.pdf

[16] See IPL 2014 IRP, p.152.

[17] http://www.eia.gov/naturalgas/weekly/archive/2015/01_15/index.cfm

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[redacted]

Confidential Figure 4: Ventyx Fall 2013 Natural Gas Price Forecasts

3.3. Other environmental compliance costs

The IRP discusses the various existing and future environmental regulations that "may require additional investment for compliance."[18] However, it is likely that the Company's preferred Plan 1 (which involves conversion of Harding Street Station 7 to natural gas and status quo operation of the Petersburg plant) and the other four scenario resource plans do not include these potential costs. It also appears that the Company's eight modeling scenarios failed to account for all of the potential costs associated with these environmental compliance obligations.

In the description of its four environmental sensitivities, IPL explains that it "considered four environmental landscapes around costs and timing of effective dates for proposed CO2 regulation" and goes on to describe the four CO_2 scenarios used to evaluate its five scenario resource plans.[19] While the costs of complying with the Mercury and Air Toxics Standards (MATS) and National Pollution Discharge Elimination System (NPDES) requirements seem to have been accounted for in the IRP modeling, the Company's analysis does not appear to account for costs associated with complying with other existing or foreseeable environmental regulations. For example, given recently proposed ozone standards from EPA, there is a significant likelihood that a selective catalytic reduction will be required on Petersburg unit 4 at a cost of approximately $150 million. When asked at the third IRP meeting if IPL modeled this

[18] IPL 2014 IRP, p.28.
[19] IPL 2014 IRP, p.51.

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possibility, the Company claimed they had not done so - even though the more stringent federal ozone standards expected to affect counties nearby IPL's coal units (as we describe below).

Capital Costs

While IPL's IRP identifies a number of existing and future environmental regulations that will impact its coal-fired resources, and even provides a table with potential cost estimates and compliance timeframes, the Company does not appear to have included these costs in its modeling scenarios at all, including the following:

- **Cross State Air Pollution Rule:** The Company acknowledges that the CSAPR rule has been reinstated and that, depending on how EPA implements the rule now that the stay has been lifted, it "may be required to purchase NOx and/or SO2 allowances on the open market to supplement our compliance plan."[20] On November 21, 2014, EPA issued a direct final rule implementing the reinstated CSAPR rule. The rulemaking rolls the original deadlines for three years (moving Phase 1 to January 1, 2015 and Phase 2 to January 1, 2017) and establishes the unit-level allocations under the CSAPR Federal Implementation Plans. The Company should evaluate whether additional costs will be required under the reinstated CSAPR rule. Further, the Company should consider the likelihood that, during the planning period, the CSAPR rule will be made more stringent in response to strengthened National Ambient Air Quality Standards (NAAQS) for particulate matter and ozone. The current CSAPR rule was designed to help states meet the 1997 ozone standard and the 2006 PM2.5 standard. In 2008, EPA strengthened the ozone standard, and on November 25, 2014, EPA proposed to again strengthen the ozone standard. EPA also finalized a more stringent fine particulate matter standard at the end of 2012. These revised standards will require additional emission reductions in many states, including Indiana.

- **SO_2 NAAQS**: The Company acknowledges that Harding Street, Eagle Valley, and Petersburg units all operate in areas that have been designated nonattainment for the 2010 1-hour SO_2 standard. The state of Indiana has published proposed SO_2 SIP limits for IPL facilities and the Petersburg station "will likely require enhanced operation of the existing FGDs to further reduce SO2 emissions" by the January 2017 SIP deadline.[21] These "enhanced operations" are not described in the IRP. The Petersburg units are each already equipped with wet scrubbers; however, because the scrubbers on units 1 and 2 are very old, and units 3 and 4 had their older scrubbers upgraded in 2006 and 2011 (respectively), the units are still required to reduce SO_2 emissions further to meet the SIP limits. Cost estimates for SO_2 compliance are not broken out in the IRP, but in a recent public filing made by the Company in Cause No. 44540, Company Witness

[20] IPL 2014 IRP, p. 37.

[21] IPL 2014 IRP, p. 38.

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Angelique Oliger identifies over $27 million in costs associated with SO_2 compliance obligations for the Petersburg units.[22] The Company should incorporate those estimates into its IRP modeling scenarios.

- **Ozone NAAQS**: The Company acknowledges the potential risks posed by a revision of the ozone standard. On November 25, 2014, EPA released its proposal to strengthen the 8-hour ozone NAAQS to a standard in the 65 to 70 ppb range, based on extensive scientific evidence about ozone's negative effects.[23] EPA is also taking comments on whether a 60 ppb standard would be appropriate. Several counties in Indiana are still not meeting the less stringent 2008 ozone standard of 75 ppb. It appears likely that EPA will designate additional areas in Indiana as non-attainment for the new standard when it is finalized. In particular, Knox and Warrick counties, which border Pike County, where the Petersburg plant is located, are currently exceeding a 70 ppb standard based on 2011-2013 monitoring data (there is no ozone monitor located in Pike County) and other nearby counties are also exceeding the 70 ppb standard.[24] This more stringent ozone standard will likely drive significant additional NOx emission reduction requirements, such as the installation of selective catalytic reduction (SCR) technology, on the Petersburg coal-fired units that are not currently well-controlled; however, IPL does not appear to have included the capital costs for such controls in *any* of its scenarios. While the cost estimate for the SCR is not broken out in the IRP, in the recent CPCN filing in Cause No. 44540, Company Witness Oliger identifies the potential need for an SCR unit on Petersburg unit 4 due to the impending revision to the ozone standard. Ms. Oliger estimates that an SCR on Petersburg 4 would cost over $146 million and would be needed prior to 2020.[25] This could have a significant impact on the economic viability of this unit and should be included in the IRP modeling scenarios.

- **Coal ash:** The Company acknowledges that the EPA's final coal combustion residual (CCR) rule could impose compliance costs at its units of somewhere between $20 and $30 million. However, IPL does not appear to include any of these compliance costs in its IRP analysis.

- **Effluent:** The Effluent Limitation Guidelines (ELG) promulgated by EPA pursuant to the Clean Water Act will require changes to handling of fly and bottom ash at coal units. The Company does not actually discuss the ELG rule in the IRP, but it does provide an estimate of potential costs from the rule ranging from zero to $43 million. Again, it does

[22] *See* Cause No. 44540, Direct Testimony of Angelique Oliger, Attachment AO-6, page 4 of 7.

[23] U.S. Environmental Protection Agency National Ambient Air Quality Standards for Ozone, proposed rule at: http://www.epa.gov/airquality/ozonepollution/pdfs/20141125proposal.pdf

[24] See US EPA, 2014. Counties Violating the Primary Ground-level Ozone Standard: http://www.epa.gov/airquality/ozonepollution/pdfs/20141126-20112013datatable.pdf

[25] *See* Cause No. 44540, Direct Testimony of Angelique Oliger, Attachment AO-6, page 3 of 7.

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not appear that the Company incorporated any of these potential costs into its modeling scenarios.[26]

- **Cooling Water:** The Company acknowledges that it could have significant compliance obligations under the recently finalized 316(b) rule covering cooling water intake structures, but that it depends on the state's determination of Best Technology Available. IPL states that the rule could require closed-cycle cooling systems or less-costly controls like travelling screens and fish handling and return systems. The IRP identifies a range of $6 million up to $154 million.[27] It does not appear that these costs were included at any point in the IRP modeling scenarios.

Figure 5 below is directly from the IRP and shows the potential additional capital costs required to comply with existing or forthcoming environmental regulations. The high end of that range represents several hundred million dollars in compliance costs being faced largely by the Company's Petersburg plant—and does not even include additional costs associated with carbon emissions.

Rule	Earliest Expected Compliance Date	Preliminary Estimated Capital	Preliminary Estimated Annual O&M
CSAPR	January 2015	$0	$0
CCR*	Late 2019	$21M-$30M	$3M-$35M
CWA 316(b)	2020	$6M-$154M	$0M-$6M
ELG	2018	$0M-$43M	$0M-$1M
GHG	2020	TBD	TBD
NAAQS	2017	$27M-$174M	$13M-$15M

*Includes estimated pond closure costs for the Petersburg Generating Station. It does not include the Eagle Valley Generating Station and HSS pond closure costs because IPL will incur those costs at the time they cease burning coal regardless of CCR outcome.

Figure 5: IPL's Estimated Cost of Environmental Regulations (Figure 3.2 in IRP)

If IPL failed to account for these potentially significant capital investments in its IRP modeling, it would represent a serious flaw in the Company's analysis. Additional environmental compliance costs are highly likely in that timeframe, and it is imprudent for the utility not to account for them in future planning. Ignoring these costs would unreasonably bias the Company's decision-making process towards continued investment in its coal units while inadequately mitigating certain risks for ratepayers. The recent CPCN filing (Cause No. 44540) provides unit-by-unit analysis with low and high bounds of environmental compliance costs for future rules.[28] We have not determined whether that modeling was sufficient, however, the clearly identified risks in that proceeding should also be addressed in the IRP modeling.

[26] The conclusion that none of these costs were incorporated is also based on informal data responses.

[27] IPL 2014 IRP, p 40.

[28] *See* IURC Cause No. 44540, Direct Testimony of James Ayers.

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Operating and Maintenance Costs

Annual operations and maintenance (O&M) for its units would also increase due to environmental compliance. The O&M costs for each unit are critical to determining the economics of each unit. If in fact, the Company failed to include O&M costs associated with other environmental regulations, it would artificially increase the coal units' forecasted dispatch, and thus unreasonably inflate the associated forecasted revenue from those units.

Recommendations:

1. The Company should use a non-zero, variable carbon price in all scenarios. The <u>zero variable cost</u> of carbon in IPL's base, low gas and high gas scenarios biases both the dispatch and long-term acquisition of the Company's system towards more, rather than less, carbon-intensive resources. In light of proposed carbon regulations, this oversight places an unreasonable amount of risk on IPL's ratepayers. *See* 170 IAC 4-7-8(b)(7)(B)(i).

2. The natural gas and energy market prices are [redacted] in the short-term and should be re-evaluated in the long-term. Given that Ventyx is using its outdated "Fall 2013 Reference Case" assumptions, these inputs should all be updated.

3. The sensitivity for carbon could also be conducted in combination with other variables (e.g. natural gas prices) to further explore bounds of risk. *See* 170 IAC 4-7-8(b)(7)(C).

4. IPL should incorporate into its forecasting the potential capital costs associated with all existing and pending environmental regulations, including CSAPR, all NAAQS, CCR, ELG, new source review compliance, and 316(b). While the precise costs associated with all of these rules may not be known with certainty, the Company should account for this uncertainty by analyzing a range of potential capital costs that account for varying levels of stringency. A failure to consider these costs in the IRP renders continued operation of the coal units artificially attractive. *See* 170 IAC 4-7-8(b)(7)(B)(i).

4. Demand-Side Management

4.1. Treatment of DSM in IRP modeling

The Company's load forecast assumptions are critical since they determine how much capacity is needed to serve demand on the system at peak times. Simply put, higher peak load means a more costly portfolio since more generation build-out is needed. Demand-side management (DSM) measures reduce peak load through Demand Response (DR), which is only called upon during peak hours, and through Energy Efficiency (EE), which is spread among hours throughout the day. Thus, DR directly reduces peak load but has little effect on energy sales, while EE reduces sales and also reduces peak load as it coincides with peak hours. Additional DSM directly reduces the Company's capacity and energy requirements, avoiding the need to build or retrofit supply resources and generation to meet load.

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Energy efficiency is a least-cost energy resource, with an average levelized cost of only 2.8 cents per kWh, based on a national review.[29] It is also a building block in the recently proposed carbon regulation by the EPA. For these reasons, DSM should be treated more seriously in this IRP, including modeling it commensurately with generation in the Company's resource planning--as is mentioned in the IRP rules--rather than as a fixed resource.

4.2. Assessing the IPL DSM Action Plan and AEG Potential Estimates

As a part of required DSM filings and the IRP process, Indianapolis Power & Light Company commissioned the Applied Energy Group (AEG) to develop both a short-term DSM action plan and a longer-term DSM forecast. The reports cover 2015-2017 and 2018-2034, respectively. The long-term forecast – hereafter referred to as the "AEG DSM potential study" – is included as Attachment 4.7 to the IRP. The following section provides a high level overview and analysis of IPL's DSM action plan and the DSM forecast. Highlights of our review include the following:

- IPL has reduced its DSM goals following passage in 2014 of Senate Enrolled Act (SEA) 340, which repealed the state's DSM energy savings goals and discontinued the statewide third party DSM administrator (TPA).
- There remain plenty of areas for improvement in the short-term action plan, most notably in achieving savings especially in the residential sector, and in re-engaging the "industrial" customers (defined as more than 1 MW) that have opted out of the DSM programs pursuant to SEA 340.
- Although EPA assumes that Indiana is capable of achieving incremental annual savings from energy efficiency at 1.5% by 2022, IPL expects to *reduce* annual incremental savings from its DSM program over time.
- Compared to other DSM potential studies surveyed from other jurisdictions, AEG's DSM savings potential estimates for IPL are disconcertingly low.
- Finally, it appears that the low savings potential estimates in the AEG DSM potential study are the result of a conservative set of assumptions and methodology to estimate DSM potential.

The short-term DSM action plan that provides the savings goals proposed in IPL's IRP is an important piece of the DSM and resource procurement puzzle. However, we have a number of concerns with the study – from the assumptions used as inputs, to the methodology used to select a DSM plan, to the ultimate results produced.

[29] ACEEE, "The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs," March 25, 2014, available at http://aceee.org/research-report/u1402.

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For instance, the DSM plan laid out in IPL's IRP only strives to achieve savings within the residential sector. This is especially true for weatherization programs, where IPL fails to offer the comprehensive home retrofit offered by similar programs elsewhere in the country.

We are equally concerned by the inputs for the action plan and the methodology employed to select a resource plan. For instance, IPL's expected potential achievable annual incremental savings from energy efficiency measures is based upon a potential study of which assumptions are flawed and results are the second lowest level found in forty-one recent potential studies from elsewhere in the country (see Table 2). It appears that the discrepancy between the AEG study and other similar DSM potential studies is largely due to AEG modeling "realistically achievable potential" as opposed to "maximum achievable potential" or even "economically feasible potential." With such a low baseline, it is impossible to achieve the levels of DSM that may, in reality, be possible within IPL's jurisdiction. Nevertheless, AEG's estimate of cumulative energy savings of 4.8 percent by 2020, growing to 10.4 percent by 2034 provides the basis for the IPL action plan.

Further, IPL has taken a flawed approach to applying these results to the selection of its DSM resource portfolio. For instance, IPL has been quick to dismiss programs not seen as likely to provide immediate savings, such as the residential new construction program. Even though similar programs have demonstrated cost-effectiveness in other jurisdictions, while also avoiding potential lost opportunities for other EE programs, IPL has decided to cut that program from their portfolio.

Additionally, even though customers with more than 1 MW of electric capacity are eligible to and have opted out of IPL's DSM programs pursuant to SEA 340, IPL should consider opportunities to reengage these customers in IPL's DSM programs. For example, IPL did not consider the fact that a Commission investigation regarding a structured self-direct program is currently pending in Cause No. 44310. And in Cause No. 44441, Phase 2, which was an investigation into the implementation of SEA 340 with respect to the opt out of customers over 1 MW, the Commission noted in its order closing that proceeding that the following issues "may be appropriate for consideration in other Commission proceedings, such as in a utility's IRP process for stakeholder input or an individual utility's DSM tracker or program approval proceeding"[30]:

- the impact on regulated electric utilities and customers of a utility resource portfolio that does not include industrial energy efficiency resources;
- whether industrial customers that opt out should be considered "free riders" and continue paying the fixed costs of DSM programs;
- whether and how energy and demand savings from industrial customers that opt out can be used by regulated electric utilities in the IRP process;
- whether the Commission should adopt rules or guidelines to assist customers in complying with the opt out provision in SEA 340 or to require opt out customers to provide EM&V reports concerning the customers own energy efficiency measures;

[30] Cause No. 44441, Phase 2, Docket Entry at p. 5 (September 3, 2014).

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- whether an oversight board should be established to monitor and evaluate compliance with SEA 340;
- determination of a mechanism to be used by opt out customers to pay for the regulated electric utilities' administrative expenses related to implementing the opt out provisions; and
- establishment of criteria for determining "reasonable and cost effective" DSM programs and the role of various oversight boards in developing DSM programs.

IPL did not take any of these points into consideration in its IRP, nor did it include any strategy to procure those industrial DSM resources that have been lost.

The most important characteristic of a DSM action plan is that incremental annual savings targets continue to grow, at least until they plateau at an achievable level. This tenet of proper planning holds true in the context of the EPA's recently proposed Clean Power Plan, which concludes that all states can ramp up annual incremental energy efficiency savings until they reach 1.5 percent per year, at which point savings plateau into the future. Conversely, IPL's DSM action plan actually *decreases* annual incremental savings targets over time, at levels below what other states have already been able to achieve (see Table 2). Certainly creating a DSM plan is better than having no action plan at all, but with several simple tweaks, IPL could put forth a far superior action plan and achieve much greater levels of savings.

	2015	2016	2017	2020	2025	2029	2034
Baseline Forecast for total (GWh)	14,033	14,186	14,319	14,722	15,260	15,526	15,940
Cumulative Savings (GWh)							
Realistic Achievable	234	320	412	706	1,125	1,378	1,665
Economic Potential	1,163	1,323	1,495	2,057	2,914	3,438	3,911
Technical Potential	1,509	1,770	2,034	2,877	4,030	4,681	5,172
Cumulative Savings % of Baseline							
Realistic Achievable	**1.67%**	**2.26%**	**2.88%**	**4.80%**	**7.37%**	**8.88%**	**10.45%**
Economic Potential	8.29%	9.33%	10.44%	13.97%	19.10%	22.14%	24.54%
Technical Potential	10.75%	12.48%	14.20%	19.54%	26.41%	30.15%	32.45%

Figure 6: Summary of Overall DSM Energy Savings Potential for IPL (IRP Attachment 4.7, Table 5-1)

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Table 2: Comparison of Utility Savings Goals

Rank on avg. annual	Author	Jurisdiction (state, utility, or region)	Year of publication	Analysis period (years)	Cumulative	Avg. annual
1	GDS	Washington, DC	2013	10	29.40%	2.90%
2	ACEEE	North Carolina	2010	16	32.00%	2.00%
3	SWEEP	Southwest	2012	11	21.00%	1.90%
4	ACEEE	South Carolina	2009	16	27.60%	1.70%
5	Cadmus	Iowa Util. Assoc.	2012	10	17.30%	1.70%
6	GDS/Nexant	Pennsylvania	2012	10	17.30%	1.70%
7	International	ComEd (IL)	2013	6	10.00%	1.70%
8	KEMA	Xcel Colorado	2010	11	17.50%	1.60%
9	Energy Center of WI	Wisconsin	2009	10	16.00%	1.60%
10	Georgia Tech	Eastern United States	2013	21	31.50%	1.50%
11	Navigant	Kansas City P&L	2013	20	29.20%	1.50%
12	GDS	Michigan	2013	10	15.00%	1.50%
13	KEMA	Xcel (CO)	2013	8	12.10%	1.50%
14	EnerNoc	New Jersey	2012	4	5.90%	1.50%
15	ACEEE	Arkansas	2011	16	22.00%	1.40%
16	GDS/Cadmus	Vermont	2011	20	25.40%	1.30%
17	ACEEE	Ohio	2009	18	23.40%	1.30%
18	ACEEE	Pennsylvania	2009	18	22.70%	1.30%
19	Black and Veatch	FirstEnergy (OH)	2012	13	16.80%	1.30%
20	Nexant/Cadmus	Georgia Power	2012	10	15.30%	1.30%
21	ACEEE	Mississippi	2013	10	12.80%	1.30%
22	**EnerNoc**	**IPL**	**2012**	**4**	**5.20%**	**1.30%**
23	ACEEE	Missouri	2011	15	17.30%	1.20%
24	AEP Ohio (Navigant)	AEP Ohio	2011	20	22.00%	1.10%
25	ACEEE	Kentucky	2012	18	19.10%	1.10%
26	EnerNoc	Ameren (MO)	2013	15	15.90%	1.10%
27	Global Energy Partners	TN Valley Auth.	2011	20	19.80%	1.00%

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28	Global Energy Partners	ConEd (NY)	2010	9	9.00%	1.00%
29	Navigant	California	2013	12	n/a	1.00%
30	EnerNoc	Avista (WA & ID)	2013	20	17.60%	0.90%
31	ICF International	Entergy NO	2012	20	17.20%	0.90%
32	ACEEE	Louisiana	2013	17	16.00%	0.90%
33	Cadmus	Puget Sound	2013	20	16.00%	0.80%
34	Cadmus	PacifiCorp	2011	20	16.00%	0.80%
35	PA Consulting	NPC/SPPC (NV)	2009	20	15.60%	0.80%
36	Global Energy Partners	New Mexico	2011	16	11.10%	0.70%
37	Forefront Economics/Gil Peach	Duke Kentucky	2009	5	3.40%	0.70%
38	EnerNoc	Idaho Power	2013	21	12.20%	0.60%
39	Cadmus	PacifiCorp	2013	20	12.00%	0.60%
40	Forefront Economics/Gil Peach	Duke Ohio	2009	5	3.10%	0.60%
41	**AEG**	**IPL**	**2014**	**22**	**10.45%**	**0.47%**
42	Cadmus/EHI	LG&E/KU (KY)	2013	20	6.10%	0.30%

Recommendations:

1. The Company should pursue all cost-effective DSM. It is typically the lowest cost resource, leads to avoidance of new generators to be built, and lowers energy and peak load required to serve customers – thereby insulating them from fuel prices and environmental compliance risks.

2. The Company should allow the model to evaluate supply-side and demand-side resources on a consistent and comparable basis and to select it as a resource, rather than hardwiring the impact of EE as the utilities did in the 2013 IRPs. (*See* pp. 4-9 of Report of the Indiana Utility Regulatory Commission Electricity Division Director Dr. Bradley K. Borum regarding 2013 Integrated Resource Plans.)

5. Conclusion

As described in these comments, the methodology employed by IPL in its 2014 IRP is fundamentally flawed. The 2014 IRP:

- neglects to model carbon costs properly in most scenarios;
- uses outdated natural gas, energy and capacity price forecasts;
- fails to analyze the economic viability of its plants on a unit-by-unit basis;

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- includes limited scenario analyses (which themselves demonstrate that IPL may have not selected the least-cost option); and
- ignores significant future environmental compliance costs associated with continued operation of its coal fleet.

Because IPL's analysis does not include a robust and transparent evaluation of alternatives, the IRP does not represent prudent planning and may not adequately justify a subsequent request for recovery of costs associated with implementation of this plan. IPL should undertake an analysis that comports with the recommendations outlined above. These revisions are critical because they may result in changes in the Company's resource plans which could improve both their cost and their risk profiles, thereby benefiting both IPL and its ratepayers.