

CAC's Response to the Director's Draft Report for the NIPSCO 2018 Integrated Resource Plan

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We appreciate the Director's Draft Report for the Northern Indiana Public Service Company ("NIPSCO") 2018 Integrated Resource Plan ("IRP") as well as the chance to respond before the Director's Final Report is issued. Overall, we felt the Director echoed many of the key issues and conclusions identified in our comments on NIPSCO's IRP. For example, we agree with the Director that "NIPSCO's integration of an actionable Request for Proposals was very farsighted and added significant credibility to the IRP."¹ We also appreciated the Director's very thorough comments on NIPSCO's load forecasting methodology and its consideration of electric vehicles. Those comments provide significant food for thought as we review the IRPs of the remaining Indiana utilities. These comments to the Director's Draft Report are intended to provide more clarity to our comments and to add more information to the conversation regarding the modeling of energy efficiency and on the combination of stochastics and scenario analysis that may come up in future IRPs.

1 The Decrement Approach

In the Draft Report, the Director raises four concerns² about CAC's proposed decrement analysis:

- 1.) Similarity to historical approach of modeling energy efficiency as a decrement to forecasted load;³
- 2.) Decrement analysis does not result in the most cost-efficient (highest value) selection of demand side management ("DSM") programs;
- 3.) Valuation of DSM;⁴ and
- 4.) How the decrement analysis interacts with the characterization of other distributed energy resources ("DERs") with differing and unique contributions to changing load shapes.⁵

As the Director correctly notes, the decrement approach is distinct from the historical approach of fixing energy efficiency as a reduction from the load forecast. That approach nearly always took energy efficiency ("EE") as given at a set level of savings throughout the planning period. The decrement approach recognizes that 1) the avoided costs of energy efficiency do not necessarily remain the same per unit of energy saved (as it is often assumed in cost-benefit analyses of EE) and therefore some exploration of avoided costs is prudent and 2) that the characterization of EE in an IRP is often very different than the actual costs and potential for EE.

¹ Director's Draft Report, p. 29.

² Director's Draft Report, p. 34.

³ The Director notes that the difference between the historical approach and CAC decrement analysis is that the decrement approach "seeks to show how much DSM is viable." Director's Draft Report, p. 34.

⁴ The Director states "Specifically, if we understand the CAC's approach correctly, is the use of a consistent load decrement throughout the year which may over-state the value of EE in some periods and understate the value in other periods." *Id.*

⁵ We were not clear how "the contributions of EE may be improperly comingled with other DERs" since the decrements are intended to represent EE specifically and other DERs can be modeled separately, but would welcome any clarifications on this point. *Id.*

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A decrement analysis seeks to explore the value of EE from an avoided generation perspective rather than to determine what is viable.

We recognize, however, that in part because of the direct connection between Indiana IRPs and DSM plans, there is some discomfort with leaving the identification of the near-term level of EE to implement in a later docket. To address this issue, we would propose a hybrid approach in which the potential study is still used to characterize an “expected” level of savings in the next three-year plan, but is not the only level of savings explored in the DSM plan filing. The Director repeatedly emphasizes the importance of flexibility in IRPs, e.g. at page 3 of the Draft Report on NIPSCO's IRP, and we could not agree more. This was a primary motivation for our recommendation to do decrement modeling in IRPs. As it stands now, the assumption that the IRP supports a single, fixed level of incremental savings that must be in the 3-year DSM plan is incredibly rigid. Further, it is not supported by the experience of implementing EE in Indiana insofar as the utilities tend to overestimate cost and underestimate potential for EE.

The Director also raises some concerns about assuming a common load shape and whether that properly values energy efficiency. Specifically, the Director states:

The construction of the bundles necessitates the development of a single common load shape encompassing residential, commercial and small industrial end-uses in each bundle. While the formation of some type of aggregate load shape is necessary for this method of modeling EE for optimization analysis, it raises questions about the development of the common EE load shape. Even if the bundles were predicated on the highest load savings achievable in a given hour, there is still an assumption of significant homogeneity that may not capture important differing end-use load characteristics. The long-term treatment of EE is even more problematic because it suggests that, within the individual bundles and for the comparison among all the three bundles, there will be similar load shapes over the 20 plus years. The CAC's decrement approach was developed as a means to address what it sees as a problem of relying on long-term estimates of EE market potential. The decrement approach developed by CAC et al is a reasoned alternative (or supplement) to other methods in an attempt to ensure all cost-effective EE is considered. However, the implicit assumption is that the load shape decrements assume a uniform percent that remains constant throughout the year, which strains credulity. If this is an accurate characterization, the problem could be ameliorated by more granular load shape information that depicts the changing load shapes with the year and for the planning horizon.⁶

We would vigorously disagree that assuming a uniform percentage of load reduction throughout the year “strains credulity.” First, this is likely to be entirely consistent with the shape of the aggregated EE bundles modeled by the utilities. For example, Figure 1 below shows the

⁶ Director's Draft Report, pp. 20-21.

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normalized shape of the non-degraded savings modeled by I&M compared to the shape of its 2018 load.

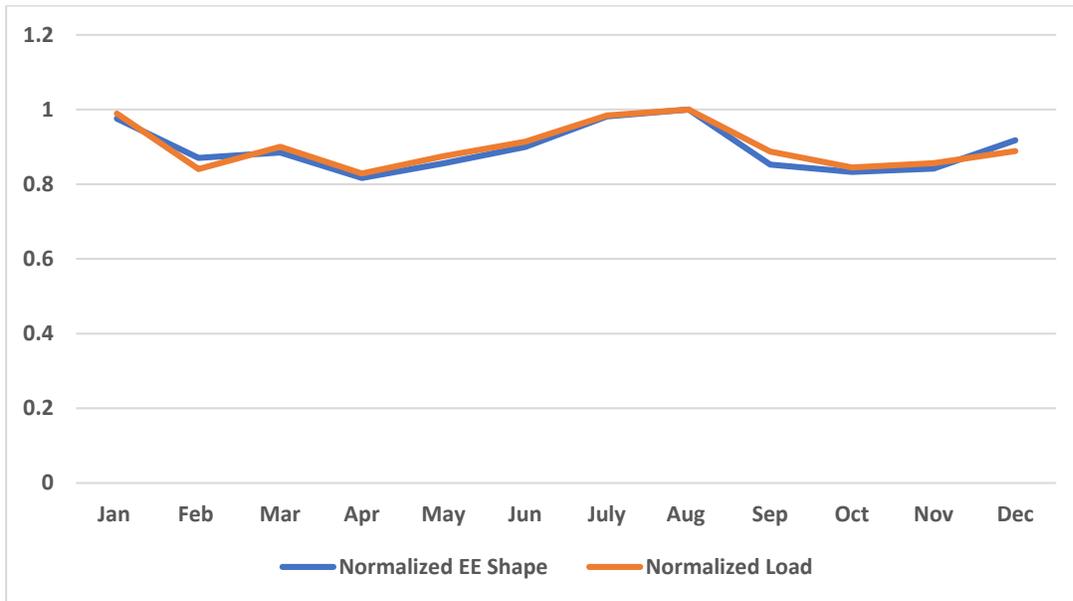


Figure 1. Shape of Normalized 2018 I&M Load and Aggregated EE Bundles⁷

The shape of load and the shape of the EE bundles are nearly identical. This makes logical sense to us since, where there is more consumption, there ought to be more opportunity to save energy cost-effectively and vice versa. Because IRPs are a long-term planning exercise, we think this is a very reasonable long-term assumption. If it is not, then the underlying load shapes of the bundles modeled by the utilities would also “strain credulity.”

Second, we understand and sympathize in many ways with the Director’s concerns about load shape data as laid out in the Draft Report. However, the manner in which more detailed load shape data could be used to improve the valuation of EE is an open question for several reasons:

1. Most IRP models cannot use hourly and sub-hourly data in resource optimization;
2. It may be the case that disaggregating EE into programs or measures is likely to reduce its value rather increase it; and
3. In our experience, the greatest limiter of EE in resource optimization is cost and availability assumptions, not shape.

We take each of these in turn.

While the movement away from Strategist and System Optimizer is generally a good thing in terms of the ability to better simulate resources like battery storage and solar plus storage and optimize a larger number of resources simultaneously, the new suite of IRP models are not

⁷ I&M Stakeholder Workshop #2 held on April 11, 2018, Slide 37. Retrieved from <https://indianamichiganpower.com/global/utilities/lib/docs/info/projects/IMIntegratedResourcePlan/April%2011%202018%20Presentation.pdf> and from Exhibit E of the I&M 2018 IRP.

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without their limitations. Most models, and therefore most IRPs, will have some timestep simplification for resource optimization purposes. This could include simulating a couple of “typical” days per month rather than all days of the month or aggregating multiple hours into a single timestep⁸ or both. This is necessary to condense the problem size into a manageable quantity. Best practice with most of these models is to then rerun the selected portfolio in an 8760 chronological production costing simulation; but this provides a more detailed look at the operation of the portfolio, it does not reoptimize the selection of any resource. If hourly or subhourly load shapes provide additional value in optimizing EE and DERs, the question becomes: how does one actually use that data for that purpose?

Second, it may be the case that disaggregating EE by program or measure, however this more specific shape data would dictate, would lead to an undervaluing of most EE. Most new IRP models are market models, meaning that they compare all resources to a market price forecast and build all cost-effective resources subject to a minimum and maximum reserve margin. So in the case that *no* resources are cost-effective, the model will build whatever resources have the least worst cost-effectiveness to meet the minimum reserve margin; and where *all* resources are cost-effective, the model will build the most cost-effective resources up to the maximum reserve margin. In our experience, most wind, solar, and gas resources are judged as cost-effective. Let's assume for argument's sake that all are equally as cost-effective as energy efficiency. Where the maximum reserve margin constraint is binding, the model will choose not to build the fewest resources possible and one or more cost-effective EE bundles will not be in the resulting plan insofar as it is the likely smaller resource of the four available resources. This would lead to the selection of a plan that could be just as optimal but with a different, decreased level of energy efficiency.

Third, in our view, the primary limiter of energy efficiency in Indiana IRPs has been overestimating cost and underestimating potential. Most recently, our review of Duke Energy Indiana's IRP showed that Duke was assuming energy efficiency costs twice or more than what it has historically. A more accurate load shape does nothing to rectify these types of fatal flaws.

All of this is not to say that load shape data should not be improved or that many of the steps the Director outlined in his Draft Report, such as increased utilization of end-use surveys, are not valuable—we agree that they are. We are just not clear how one would use this information to significantly benefit the consideration of EE within an IRP. It may be that there is a middle ground here. We suspect that the Director is well aware of literature on the topic of the time-value of EE including Lawrence Berkeley National Laboratory's (“LBNL”) report, “Time-varying value of electric energy efficiency.” The authors conclude, not surprisingly, that:

[I]n both California (Figure ES-2) and Massachusetts (Figure ES-3), savings with a residential air conditioning load shape have significantly more value than measures with other load shapes. In Georgia, (Figure ES-4) savings with a

⁸ Meaning that hours 1 – 6 may constitute one timestep, hours 7 – 11 another, hours 12 – 16 another, etc. Though not all models necessarily do this chronologically, e.g. System Optimizer.

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residential air conditioning load shape also have more value than other measures. In contrast, savings with residential air conditioning load shapes in the Northwest (Figure ES-1) have the lowest value relative to measures with other load shapes reviewed in this study. One of the underlying causes of these differences is that the California, Massachusetts, and Georgia utility systems experience their peak demands in the summer, while the Northwest electricity system peaks during the winter.⁹

Rather than expending significant effort and modeling time on identifying more granular load shapes for all measures, it may make sense to focus on those likely to provide system benefits in the most costly hours of the year. For example, if summer hours are more costly according to the utility's production costing simulations or its market price forecast, then measures that provide significant summertime savings would be candidates for further analysis. This could be forcing in greater levels of residential air conditioning savings with a more tailored load shape to test the resulting benefits, etc.

In terms of the steps for data collection to promote better load shapes, one area of disagreement between CAC and the Director is on the use of AMI data. As GridLab's guide on maximizing the public interest through grid modernization explains:

In the authors' experience, all potential sources of smart meter benefit must be maximized to ensure customer benefits exceed customer costs. An emphasis on post-deployment benefit measurement and accountability is therefore a critical component of any smart meter plan. Another common issue is missing conservation benefits, as utilities have an economic incentive (called the throughput incentive) for selling ever-higher amounts of electricity. As a result, smart meter capabilities with a conservation effect are missing from many utilities' smart meter business cases. These include time-varying rates, prepayment, and compliance with the Connect My Data standard.¹⁰

We do not believe the use case for AMI has been sufficiently developed in Indiana nor that it can be cost-effectively used to provide more information about EE or whom to target for EE measures where AMI does not already exist.

2 NIPSCO's Modeling of Energy Efficiency

While NIPSCO attempted to model CAC's proposed decrement analysis for modeling energy efficiency, it appears that NIPSCO assigned a cost to those bundles and capped the potential at the level identified in NIPSCO's Market Potential Study, both of which are significant and material changes to our proposed methodology. Further, those runs were not part of the IRP so

⁹ See p. 14 of <https://emp.lbl.gov/sites/default/files/time-varying-value-of-ee-june2017.pdf>

¹⁰ "Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders", p. 13. Retrieved from http://gridlab.us/wp-content/uploads/2019/04/GridLab_VAGridMod_Final.pdf

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we have had no opportunity to evaluate their merits. We look forward to the opportunity to do so in NIPSCO's next DSM plan filing.

3 Resource Selection and Stochastic Analysis

We agree with the Director that “scenario and probabilistic analysis are complimentary rather than being substitutes.”¹¹ We would go a step further and say that sensitivity and probabilistic analysis are complimentary rather than substitutes and that not all variables of significance are appropriate for stochastic analysis. As we have stated in several pre-IRP stakeholder workshops, we strongly believe that stochastic analysis is appropriate only for variables with volatility, with randomness. Variables such as the capital cost of new resources are not volatile or random, but uncertain. For IRP purposes, we think stochastics are best limited to market prices, fuel prices, and load. Furthermore, the probability distributions that underlie stochastic simulation are projections themselves and complex enough that they are often subjective, black box assumptions with significant implications for the overall IRP and preferred plan selection. For many variables that the Indiana utilities subject to stochastic analysis, e.g., carbon prices, the data does not reasonably exist to develop meaningful probability distributions. For all these reasons, we remain concerned about the overreliance on stochastic analysis amongst the Indiana utilities.

With regards to the two-stage retirement and replacement analysis, the Director states:

*Despite the reasonableness of the two-stage analysis, both its rationale and the implementation, the Director would have liked to have seen a resource optimization with the timing of retirements and replacement options minimally constrained. We recognize that there are good reasons why the resulting portfolio might be unreasonable, but it still would have been a useful point of comparison.*¹²

We wholeheartedly agree. This is good practice amongst all the Indiana utilities. Constraints are almost always necessary to derive distinct portfolios, but a largely unconstrained optimization is very useful as a point of comparison.

4 Conclusion

We reiterate our appreciation for the Director's very thorough Draft Report on NIPSCO's 2018 IRP. It is attentive to both issues raised by stakeholders and those identified by the Director. Our primary ask of the Director is to reconsider the Report's language around the decrement approach. We welcome continued dialogue on this and other issues of importance to IRPs in Indiana.

¹¹ Director's Draft Report, p. 5.

¹² Director's Draft Report, p. 27.