DRAFT

DIRECTOR'S REPORT

for the

2016 Integrated Resource Plans

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Director of Research, Policy, and Planning

on behalf of the

Indiana Utility Regulatory Commission

IRPs Submitted by

Indianapolis Power & Light Company (IPL)

http://www.in.gov/iurc/files/ipl%202016%20irp_without%20attachments.pdf,

Northern Indiana Public Service Company (NIPSCO)

http://www.in.gov/iurc/files/NIPSCO%202016%20IRP%20Without%20Appendices.pdf ,

Vectren (SIGECO),

http://www.in.gov/iurc/files/SIGECO%202016%20IRP.pdf

and

An Update by Hoosier Energy

http://www.in.gov/iurc/files/Hoosier%20Energy_public%20version_2014%20irp%20update_110116.pdf

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EXECUTIVE SUMMARY

2016 INTEGRATED RESOURCE PLANS

Indianapolis Power & Light, Northern Indiana Public Service Company, Vectren, and Hoosier Energy

Purpose of IRPs

By statute[1] and rule,[2] integrated resource planning requires each utility that owns generating facilities to prepare an Integrated Resource Plan (IRP) and make continuing improvements to its planning as part of its obligation to ensure reliable and economical power supply to the citizens of Indiana. One of the primary goals of a well-reasoned, transparent, and comprehensive IRP is to narrow the contested issues and reduce the controversy to expedite Indiana Utility Regulatory Commission (IURC or Commission) proceedings for the benefit of customers, the utility, and the utility's investors. A key element in achieving this goal, as required by law and rule, is a public advisory process, otherwise known as a stakeholder process. At the outset, it is important to emphasize these are the utilities' plans. The Commission, by statute[3], does not take a position on the relative efficacies of any of the utilities' "Preferred Plans."

An IRP is a systematic approach to better understand the complexities of an uncertain future so utilities can maintain maximum flexibility to address resource requirements. Because absolutely accurate resource planning 20 years into the future is impossible, the objective of an IRP is to bolster credibility in a utility's efforts to capture a broad range of possible risks.[4] By identifying uncertainties and their associated risks, utilities will be better able to make timely adjustments to their resource portfolio to maintain reliable service at the lowest delivered cost to customers that is reasonably feasible.

Every utility and stakeholder anticipates substantial changes in the state's resource mix due to several factors,[5] and increasingly, Indiana's electric utilities are using IRPs as a foundation for their business plans. Since Indiana is part of a vast interconnected power system, Indiana is affected by the enormity of changes throughout the region and nation. Inherently, IRPs are very technical and complex in their use of mathematical modeling that integrates statistics, engineering, and economics to formulate a wide range of

[1] Indiana Code § 8-1-8.5-3.

[2] 170 IAC 4-7; *see also* "Draft Proposed Rule from IURC RM #11-07 dated 10/04/12", located at: http://www.in.gov/iurc/2843.htm ("Draft Proposed Rule")

[3] Indiana Code § 8-1-1-5.

[4] In addition to forecasting changes in customer use of electricity (load forecasting), IRPs must address uncertainties pertaining to the fuel markets, the future cost of resources and technological improvements in resources, changes in public policy, and the increasing ability to transmit energy over vast distances to access economical and reliable resources due to the operations of the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM).

[5] The primary *driver* of the change in resource mix is due to relatively low cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to *fracking* and improved technologies. As a result, coal-fired generating units are not as fully dispatched (or run as often) by MISO or PJM. The aging of Indiana's coal fleet, the dramatic decline in the cost of renewable resources, the increasing cost-effectiveness of energy efficiency as a resource, and environmental policies over the last several decades that reduced emissions from coal-fired plants are also drivers of change. Inherently, IRPs are forward looking so it is important for IRPs to consider a broad range of potential changes in environmental and other public policies.

possible narratives about plausible futures. The utilities should utilize IRPs to explore the possible implications of alternative resource decisions.

The IRPs should be regarded as *snap shots in time* that analyze multiple potential resource portfolios. Because IRPs are usually submitted to the Commission in November, changes occurring after submittal, such as any roll-back of environmental regulations through law, rulemaking, or executive orders (e.g., the Clean Power Plan (CPP)), review of Effluent Limitation Guidelines (ELG) rule, policy emanating from international agreements such as the Paris Accord, newly-discovered natural gas opportunities, and changes in technology do not normally require changes to this IRP. Statutorily, it is the utility's decision whether to modify their IRP or create a new IRP to support a case for a change in resources. Minor and significant changes will occur after submittal (or after the expensive and technically demanding modeling work has been completed). To avoid perpetual IRPs that are never completed as circumstances are always changing, modifying or preparing a new IRP to support a filing of a Certificate of Need case or other case may be appropriate. Such a decision is at the utility's discretion under the law and the Commission will evaluate the reasonableness of the utility's decision. As a result, these resource portfolios should not be regarded as being THE Plan that a utility commits to undertake. Rather, it should be regarded as a road map based on the best information and judgment at the time the analysis is undertaken. The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public policy, technological changes that change the cost-effectiveness of various resources, customer needs, etc.) and make appropriate and timely mid-course corrections to change their resource portfolios. Again, it is important that these decisions be made with stakeholder involvement.

Four Primary Areas of Focus

The Director recognizes the complexity of the several elements of IRPs and has selected the following four to highlight:

1) Fuel and commodity price forecasts;
2) Construction of resource portfolios based on the development of a wide range of scenarios and sensitivities;
3) The treatment of Demand-Side Management (DSM) on as comparable a basis as possible with all other resources; and
4) Discussion of the metrics that each utility considered to evaluate the IRPs.

The focus on these four areas is due to the complexity and difficulty of these topics but it should not be interpreted as suggesting that other topics such as the stakeholder process, load forecasting, and integration of customer-owned resources are not important to the credibility of the IRPs and the value to utilities and stakeholders.

General Observations

Perhaps due in part to the increasingly consequential decisions that utilities will be making, and in part to the commitment of the utilities and stakeholders to the IRP public advisory processes as good public policy, Indianapolis Power and Light Company (IPL), Northern Indiana Public Service Company (NIPSCO), and Southern Indiana Gas and Electric Company (Vectren) have all made significant improvements in all aspects of their IRPs. Indiana utilities are increasingly using state-of-the-art methods and are making continued enhancements to their planning processes. The utilities have all made a concerted effort to broaden stakeholder participation. All of the utilities have offered unprecedented transparency and candor. It is gratifying that the top management of each utility, top staff and subject matter experts have all been made available to facilitate the collegial stakeholder process.

Consistent with the law and the Draft Proposed Rule, each Indiana utility has recognized areas that will be improved in subsequent IRPs. For example, all three utilities recognized the need for improvements in their load forecasting, and IPL is undertaking an ambitious project to utilize "smart meters" (Advanced Metering Infrastructure or AMI) to increasingly rely on its own customers' usage data rather than reliance on information from other utilities. NIPSCO recognized the need to upgrade its modeling capabilities because its current long-term resource model was not capable of integrating probabilistic analysis or performing multiple optimizations of different resources. All utilities are committed to enhancing their stakeholder process. By going from a two year to three year IRP cycle, utilities can increase stakeholder input by: 1) establishing objective metrics to evaluate their IRP; 2) defining the assumptions (e.g., fuel prices, costs of renewable resources, costs of other resources); 3) constructing scenarios to provide a robust assessment of potential futures; and 4) reviewing the resulting resource portfolios.

In the four focus areas, the Director recognizes there is no right or wrong way to conduct the analysis; different approaches have been useful to advance the understanding of the various elements of IRPs but it is premature to standardize.

1. INTRODUCTION AND BACKGROUND

Since 1995, Indiana utilities that generate electricity have submitted IRPs. In 2016 by explicit statute[6] and rule,[7] the Commission requires each utility that owns generating facilities to prepare an IRP and make continuing improvements to their planning as part of their obligation to ensure the reliable and economical power supply to the citizens of Indiana. For several reasons (such as projected low cost natural gas, aging power plants, environmental regulations, decreasing cost of renewable energy resources, energy efficiency, customer-owned resources, and relatively low load growth), all Indiana utilities, in addition to utilities throughout the region and nation, are facing significant resource decisions that will largely remake the resource mix. One of the primary goals of a well-reasoned, transparent, and comprehensive IRP is to narrow the contested issues and reduce the controversy to expedite Commission proceedings for the benefit of customers, the utility, and the utility's investors. For the IRPs submitted on or after Nov. 1, 2012, the utilities voluntarily adhered to the Draft Proposed Rule from IURC RM #11-07 dated 10/04/2012 (Draft Proposed Rule), which proposed to modify 170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans. The Commission, utilities, and stakeholders collaboratively developed the Draft Proposed Rule, which is available on the Commission's website at http://www.in.gov/iurc/2843.htm

(IPL and NIPSCO submitted their IRPs on Nov. 1, 2016. Also on November 1, Hoosier Energy submitted an update to its 2014 IRP. Vectren was granted an extension to allow for a better understanding of the issues associated with ALCOA and larger customers generally, and submitted its 2016 IRP on December

[6] Indiana Code § 8-1-8.5-3.

[7] 170 IAC 4-7; *see also* "Draft Proposed Rule from IURC RM #11-07 dated 10/04/12", located at: http://www.in.gov/iurc/2843.htm

19, 2016. Links to the IRPs, appendices, and other documents can be found at http://www.in.gov/iurc/2630.htm.

Please note that the links shown below for each utility are public versions of the IRPs and do not include confidential information and most appendices:

1. Indianapolis Power & Light Company (IPL)

   http://www.in.gov/iurc/files/ipl%202016%20irp_without%20attachments.pdf

2. Hoosier Energy REC, Inc. (Hoosier Energy)

   http://www.in.gov/iurc/files/Hoosier%20Energy_public%20version_2014%20irp%20update_110116.pdf

3. Northern Indiana Public Service Company (NIPSCO)

   http://www.in.gov/iurc/files/NIPSCO%202016%20IRP%20Without%20Appendices.pdf

4. Southern Indiana Gas & Electric Company (SIGECO or Vectren)

   http://www.in.gov/iurc/files/SIGECO%202016%20IRP.pdf

Written comments regarding some of the IRPs were submitted by various entities, including:

1. Citizens Action Coalition, Earthjustice, IndianaDG, Sierra Club, Valley Watch (hereinafter referred to as CAC et al.)
2. Midwest Energy Efficiency Alliance
3. Indiana Coal Council
4. Alliance Resource Partners, LP
5. NIPSCO Industrial Group
6. Sunrise Coal, LLC
7. Joe Nickolick
8. Office of the Utility Consumer Counselor.

Links to these comments can be found at: http://www.in.gov/iurc/2630.htm

Section 2(k) of the Draft Proposed Rule limits the Director's Draft Report and Final Report to the informational, procedural, and methodological requirements of the rule, and Section 2(l) of the Draft Proposed Rule restricts the Director from commenting on the utility's preferred resource plan or any resource action chosen by the utility.

This Draft Report by the Director was issued July 28, 2017. Under the Draft Proposed Rule, supplemental or response comments to the Director's Draft Report may be submitted by the utility or any customer or interested party who submitted written comments on the utility's IRP earlier in the process. Supplemental or response comments must be submitted within 30 days from the date the Director issues the Draft Report. The Director may extend the deadline for submitting supplemental or response comments.

According to the Draft Proposed Rule, the Director shall issue a Final Report on the IRPs within 30 days following the deadline for submitting supplemental or response comments. The Director would be pleased to meet with utilities and/or stakeholders to discuss the Draft or Final Reports.

1.1 Summary

The 2016 IRPs submitted by IPL, NIPSCO, and Vectren were credible, well-reasoned, and represented a substantial improvement over previous years in all aspects of their IRPs. The utilities are increasingly viewing their IRPs as integral to their strategic planning and having substantial ramifications for their customers, investors, communities, and for policymakers. Certainly all three utilities are facing potentially dramatic changes in their resource mix over the next several years due to the following factors affecting the nation as a whole:

- The aging of the coal and nuclear generating fleets when combined with more stringent environmental regulations may accelerate retirement decisions. This is especially true for the smaller and older coal-fired generating units. In the next few years, decisions to retire larger and more efficient generating facilities that have far-reaching ramifications for the each utility's customers, the region, and the nation are certain to require increasingly difficult and rigorous analysis. Indiana law requires the Commission to consider the broad public interest when evaluating resource decisions and their consequences in CPCN processes or other proceedings. The Commission's authority does not extend to pre-approval of a utility's decision to retire resources. Nevertheless, the law requires the Commission to exercise its authority over the consequences of the utility's resource decisions, including ensuring that older generating facilities are not closed prematurely.
- In general, coal and nuclear generating units are having difficulties competing with natural gas and renewable resources in the regional economic dispatch of competitive wholesale power markets. That is, for regional economic dispatch by MISO or PJM, coal and even some nuclear units that serve other states are often "out of the money" and not dispatched as fully as they were as recently as two years ago and therefore unable to recover all of their fixed and variable operating costs. As a result, several utilities have planned to retire substantial portions of their coal-fired units. Nuclear units are increasingly struggling in the current market. Utilities in Ohio, Illinois, and other states are seeking state legislation to have customers subsidize the continued use of nuclear- and coal-fired generators. Against this backdrop of declining natural gas prices and increased cost-effectiveness of renewable resources, utilities evaluating the retention of coal and nuclear units will need to continually reevaluate the value of fuel and resource diversity while maintaining resource adequacy.
- Utilities are facing increasing costs due to maintenance and modernization of infrastructure. These utilities are also projecting low or even negative growth in electric sales, which means the increased costs will be spread over fewer kilowatt hour sales.
- Because the decisions about resources will become increasingly complex, contentious, and difficult, utilities will have to continually enhance their planning processes. In addition to dramatic changes in fuel markets and the cost of renewable resources, utilities will have to consider the planning ramifications of future potentially significant public policy changes, such as the roll-back of some environmental regulations (e.g., the CPP, ELG, Presidential Executive Orders, etc.).

With good reason, IPL, NIPSCO, and Vectren have sought to maintain as much optionality as possible in their IRPs. The Navy uses the phrase "point of extremis" to characterize maximum optionality. That is, waiting to make a very difficult decision until the last possible moment. To this end, the IRP analysis –

including the utility's selection of a preferred resource portfolio – should be regarded as an indicative analysis, in that the results are based on appropriate information available at the time the study was being conducted and does not bind the utility to adhere to the preferred resource portfolio, or any other resource portfolio. If there is information to support a different outcome in a matter before the Commission after an IRP used to support a resource decision is completed, the utility should assess whether an update to the IRP is appropriate. Ultimately, in the instance of a case before the Commission, the Commission, after consideration of testimony, will decide whether additional analysis is necessary to provide the Commission with the requisite information.

1.2 Areas of Primary Focus

The Director's Report of the 2016 IRPs for IPL, NIPSCO, Vectren, and an update by Hoosier Energy will primarily address the four most difficult and significant interrelated topics that were the subject of considerable conversation throughout the stakeholder processes. The four topics are: 1) fuel and commodity price projections; 2) scenario and risk analysis; 3) development of metrics for evaluating the IRPs; and 4) the treatment of energy efficiency on as comparable a basis as possible to other resources.

Utilities, in conjunction with stakeholders, will be evaluating future resource modeling programs, databases, and utility planning processes to continually enhance the credibility of the IRP processes. This continual reevaluation is imperative as decisions become increasingly complex. Just because these other topics are receiving a more cursory review should not be construed as being less important. It is also worth emphasizing that the individual topics being reviewed are all interrelated, which makes clear delineation between the topics impossible. The Director wishes to be abundantly clear that the comments address the methods used in the IRP process rather than the selection of a preferred resource portfolio.

The Director believes this has been the most transparent IRP process to date. The new three-year cycles contained in the more recent draft IRP rules will further reduce concerns and questions by affording stakeholders an opportunity to become more involved in the development of the IRPs from their inception through submittal. Most stakeholder concerns and questions about this and previous IRPs centered on the development of portfolios. This included developing assumptions, selection of appropriate data, construction of scenarios, the use of meaningful sensitivities, and the evaluation of model output and the resulting resource portfolios to reliably and economically meet the needs of Indiana. Stakeholder interest and participation in the IRP processes is likely to intensify as decisions to retire and restructure the resource mix are made.

From the analysis and the stakeholder comments, IPL, NIPSCO, and Vectren made significant improvements to their IRP analysis and their approaches. It is abundantly clear that Indiana utilities, like utilities throughout the nation, are facing daunting issues and there is no easy, single or perfect answer to address these issues. In some respects, Indiana utilities are on the cutting edge of long-term resource planning. The advances made by Indiana utilities should result in lower risk for their customers and investors. As Indiana utilities and their stakeholders realize, however, continued improvements is a goal we all share.

1.3 Presentation of Basic Information

The Director tried to compile the same set of basic information for each utility's IRP and found the task surprisingly difficult. For example, the Director tried to compare for each utility how its portfolio changed from the beginning of the forecast period to how it looked in the last year of the period. This information was presented in terms of generation capacity in either the IRP, appendices, or presentations from the public advisory stakeholder meetings. But comparable information showing how much energy was provided by resource type and how this changed over the forecast horizon was not presented by IPL and Vectren. Some of the basic information was presented by each utility in their IRP but no utility had all of the information in its IRP. Some of the information one utility had in its IRP was not included by other utilities but could be found in the stakeholder presentations. Some of the basic information could not be found in the IRPs, stakeholder meeting presentations, or other technical appendices. Even when utilities presented what appeared to be similar information, a closer examination showed the data was not comparable. Based on comments by the CAC et al., it appears they had much the same experience.

The problem is the IRPs and the associated appendices each provide a considerable amount of information but much is also not available, not well presented or must be laboriously sought and compiled, or is not comparable across utilities. These limitations reduce the usefulness of the IRPs to non-utility stakeholders and can be increasingly problematic over time for utilities, stakeholders, and policymakers. Without being unduly prescriptive, but in an effort to improve the immediate and longer-term value of the IRPs, the Director makes several suggestions that he hopes will serve as a starting point for a discussion that will involve the utilities and numerous stakeholders.

1. Make much greater use of tables and figures comparing resource retirements, additions, and other inputs across both the preferred and candidate portfolios. Examples are on Table 23 on page 131 of Indiana Michigan's 2015 IRP. Another example for consideration is Table 2 on Pp. 11 of the CAC et al. comments on Vectren's 2016 IRP.

2. Include tables showing how inputs or assumptions compare across scenarios. To make scenarios clearer, there needs to be a link of each scenario description to specific inputs. (CAC et al. Comments on Vectren IRP, Pp. 19). For example, which fuel forecasts were used in each scenario should be clearly specified.

3. The first year any resource is available for selection in a portfolio should be presented and the reason why some resources might be available later than others should also be noted. More specifically,

   - The first year a resource can be added to a portfolio;
   - The last year a resource can be added to a portfolio;
   - Limitations on the size of the resource that can be added;
   - The minimum and maximum number of units of a particular resource that can be added; and
   - Performance characteristics of generation facilities including forced outage rates, heat rate profiles, emission rates, and typical maintenance outages.

Also, if the availability of potential resources for model selection varied by scenario, then this should also be clearly presented. As mentioned by CAC et al, for each scenario or portfolio, it is important to note which resource changes are fixed (or set by the modeler) as compared to optimized (chosen by the model based on the constraints set by the modeler). (See pp. 10 of CAC's Comments on Vectren IRP)

4. The non-utility stakeholders would benefit from expanded use of graphics and simple tables. Well-developed graphics would aid a wide variety of audiences.

5. Given that future IRPs are going to be increasingly consequential in their ramifications, we urge all utilities to continue their efforts to improve the clarity and explanatory value of their narratives. With the new three-year cycle for IRPs, we recommend the additional time could be used to good effect to solicit input from stakeholders earlier in the process on the data, assumptions, and the development of scenarios and sensitivities. It is expected that stakeholders will also be active participants in this collaboration. The utilities, with input from their stakeholders, should objectively reassess their modeling capabilities and the databases necessary to make full use of state-of-the-art long-term resource modeling.

2. INDIANAPOLIS POWER AND LIGHT COMPANY

2.1 IPL'S Fuel and Commodity Price Analysis for 2016 IRP

Since natural gas price projections and the relationship between gas and coal prices seem to be the primary driver of the IRPs this round, the Director believes more discussion about the assumptions behind the fuel and commodity forecasts and data are warranted. We very much appreciate IPL's willingness to share confidential information from its consultants, which provided a narrative of its fuel and market price projections. However, the narratives did not seem to provide a comprehensive discussion of the complexities of the interrelationships of critical commodities. For example, the production and price relationship of oil to natural gas, natural gas to coal, and fuel prices to MISO market prices.

> *Natural gas/market price correlations – While IPL recognizes potential influences of resource mix changes on market prices, in this IRP correlations between fuel and market prices do not change significantly from recent historic trends. IRP Assumptions, 1.3* page 2

As a result of giving less consideration to fracking as a significant departure from historic trends, it appears that IPL may minimize the complex and changing interrelationships between oil price and production and the production and price of natural gas. To the extent that this concern may be valid, we offer some potential examples but encourage IPL to consider others.

1. Figures 8.40 and 8.41in the Company's IRP shows a somewhat surprising result that coal price became more important than natural gas prices after 2027. This is certainly an interesting scenario but it might argue for construction of a scenario/sensitivity that has a low natural gas price projection.

2. If natural gas price projections are as complex as we believe, this would seem to make estimates of the market price, which is largely dependent on the price differentials between coal and natural gas (the difference between the market price and coal price is sometimes referred to as the dark spread), more difficult. On page 11 of its IRP, IPL states: "*IPL uses a combination of multi-year contracts with staggered expiration dates to limit the extent of IPL's coal position open to the market in any given year. Many of these multi-year contracts contain some level of volumetric variability as an additional tool to address market variability.*" This seems like a well-reasoned approach but it isn't clear how coal prices varied in the longer-term using stochastic analysis (page 142). Regardless, this IRP analysis, and particularly future IRP analyses, would benefit from more complete discussion of natural gas, coal, and market price intricacies.

3. For IPL, the MISO's economic dispatch and forecast of market prices provide additional data points for consideration. That is, if the projections being used by the MISO show diminishing dispatch of coal-fired power plants, that should be an additional check, but certainly not the only check in determining the reasonableness of the fuel cost assumptions. Similarly, if coal is dispatched more frequently, IPL's planning should be sufficiently flexible to adjust.

The Indiana Coal Council commented that the 2.5% annual escalation rate for coal may be too high. IPL said that might be true but, while they utilized only one coal price forecast, they conducted probabilistic analysis on a wider range of possible forecasts to evaluate their portfolios (IPLs response to Indiana Coal Council on page 1 of the ICC's letter). The Director believes IPL's approach was a reasonable method to address the ICC's concerns. However, we agree with the Indiana Coal Council that it would probably be better to have more expansive scenarios than to rely on sensitivities. As IPL's resource decisions become more difficult, we are confident IPL will be rigorous in its evaluation methods.

2.2 Scenario and Risk Analysis

2.2.1 Models, Drivers, and Scenarios

To IPL's credit, all scenarios were developed in an atmosphere of transparency, and IPL actively solicited input from stakeholders. IPL identified four categories of drivers, which would impact IPL's resource portfolio choice. They are economics affecting load requirements, natural gas and wholesale electric market prices, Clean Power Plan and other environmental costs, and the level of customer distributed generation adoption. IPL considered how these drivers might interact in the future to develop specific scenarios.

1. A Base Case scenario
2. Robust Economy,
3. Recession Economy,
4. Strengthened Environmental, and
5. High Customer Adoption of Distributed Generation
6. Quick Transition

The Base Case included business-as-usual projections for identified drivers trending as currently expected for the study period. Four scenarios were developed by varying projections of the four main categories of drivers mentioned previously. The four scenarios are Robust Economy, Recession Economy, Strengthened Environmental, and High Customer Adoption of Distributed Generation. Another scenario called Quick Transition was formed based on stakeholder feedback. There are six scenarios in total.

The capacity expansion model produced six least-cost portfolios from the six scenarios. IPL then took the six portfolios and modeled them against the Base Case assumptions in the Production Cost Model to examine how each portfolio would fare if Base Case assumptions for the future come to fruition. To better understand the impact of carbon regulation on the Base Case, IPL conducted two deterministic sensitivities on the Base Case by using the Production Cost Model to simulate the Base Case portfolio and dispatched the units subject to different carbon prices. Additionally, stochastic analysis was conducted to assess the financial risk to each portfolio if key variables changed.

Based on the criterion of lowest cost to customers combined with considerations of risk, as well as other economic and environmental impacts, IPL chose a hybrid preferred resource portfolio. The portfolio is a mix of the portfolios from the Base Case, Strengthened Environmental, and Distributed Generation Scenarios. Selecting a Preferred Portfolio that was different from the Base Case, based on IPL's judgment might be regarded as unusual but it is not inconsistent with the IRP draft rule. Selecting a Preferred Plan that incorporates stakeholder and other input demonstrates a flexibility and optionality that the IRP draft rules intended to encourage. Since all of the IRP plans are indicative, they should not be characterized as representing a commitment to adopt the elements of the plan. However, for the integrity of the stakeholder process, the utility's Preferred Plan should be derived from the scenarios that were fully optimized and reflect information developed from sensitivity and probabilistic analyses. A narrative should be sufficiently detailed to track the evolution of the Preferred Plan.

IPL worked with several vendors and utilized multiple models to conduct scenario and sensitivity analysis. The DSM Market Potential Study was conducted by AEG through LoadMap. Load forecasts were performed by Itron using MetrixND. Capacity Expansion Model from ABB was used to develop optimized portfolios under various scenarios. ABB Strategic Planning Portfolio Production Cost Model and Financial Model were adopted to evaluate portfolios by providing present value of revenue requirements (PVRRs) in a Base Case future world.

2.2.2 Issues / Questions

The Director was impressed with the level of scrutiny and in-depth analysis of the computer runs and how the modeling affected the development of scenarios, sensitivities, and, ultimately, the portfolios that were provided by the CAC et al. Giving due regard for stakeholder comments adds credibility, increases understanding, and, hopefully, will reduce the number of contentious issues inherent in the increasing complexity and analytical difficulty of future IRPs. Hopefully, many of the concerns raised by the CAC et al. regarding assumptions, data, development of scenarios, integration of sensitivities, and appropriate metrics for objective review will be addressed earlier in the IRP process consistent with the change in the rule from two to three-year cycles.

All of IPL's optimized portfolios were evaluated under the Base Case Scenario assumptions rather than the assumptions of the corresponding scenarios. IPL argued that the comparison was helpful because it allowed one to see how each portfolio performed under the same set of assumptions. However, in this case, comparison among various portfolios based on the Present Value of Revenue Requirements (PVRR) is less meaningful because the Base Case portfolio has to be the least cost portfolio under Base Case scenario assumptions, according to the least-cost optimization criterion imbedded in the capacity expansion model.

For the probabilistic analysis, IPL evaluated each candidate portfolio under 50 combinations of input variables from random draws using the Production Cost Model. IPL seems to have overlooked changes in the capacity portfolio caused by changes of input assumptions by using this method. Upon reconsideration, would IPL agree that a more appropriate way might be running the capacity expansion model first under each set of assumptions to develop the capacity portfolio and then evaluating the portfolio with consideration of the operation and financial aspects of electrical generating units through the Production Cost Model? With regard to choosing the preferred plan, a more appropriate way might be comparing capacity portfolios derived from different input assumptions first. Resources found in the majority of scenarios might be considered in the preferred portfolio. However, in the end, IPL considered six metrics it regarded as important (page 7 of the Executive Summary) and it is IPL's decision to select a preferred portfolio.

2.3 Energy Efficiency

Like other Indiana utilities, there is a marked improvement in IPL's effort to model demand side management (DSM) in a manner comparable to supply-side resources and to group the resources into bundles that are then entered as selectable resources comparable to supply-side resources in the capacity expansion modeling software. The ability to treat DSM in a manner that is as comparable as possible to other supply-side resources is difficult and there is no single or perfect methodology. Like NIPSCO in this

IRP cycle, IPL contracted the Applied Energy Group (AEG) to use their LoadMap tool to perform a market potential study and Morgan Marketing Partners (MMP) to screen the DSM measures chosen for cost-effectiveness using their DSMore tool. The DSM measures that passed the screening were then grouped into 14 bundles (eight energy efficiency-based and six demand response-based). Seven of the energy efficiency based bundles were further split into three cost tiers.

To estimate the appropriate level of achievable and cost-effective DSM suitable for IPL's service territory, IPL hired AEG to prepare a Market Potential Study (MPS).[8] While the IRP covers the period 2017 to 2036, the MPS started in 2018 and covers DSM opportunities through 2037. A key objective of the MPS was to develop estimates of electric efficiency and demand response potential by customer class for the period 2018 to 2037 in the IPL service territory and develop inputs to represent DSM as a resource in IPL's IRP for the forecast period 2018-2037.

A screening process was used to develop an Achievable Potential for DSM that was used to create the DSM bundles for the IRP modeling. The process starts with all technically possible efficiency measures, or the Technical Potential. AEG prepared a list of available efficiency measures using IPL's current programs, the Indiana Technical Reference Manual version 2.2, and AEG's data base of energy efficiency measures. AEG then applied a cost-effectiveness screen using the Total Resource Cost (TRC) test as the main metric to determine the Economic Potential. This test selects any measure which, if installed in a given year, has a TRC net present value of lifetime benefits that exceed the Net Present Value of Revenue Requirements (NPVRR) of lifetime costs.

AEG estimated two levels of Achievable Potential from the Economic Potential: Maximum Achievable Potential (MAP) and Realistic Achievable Potential (RAP). MAP estimates consider customer adoption of economic measures when delivered through DSM programs under ideal conditions and an appropriate regulatory framework. RAP reflects program participation given DSM programs under typical market conditions and barriers to customer acceptance and constrained program budgets. A downward adjustment was applied to the MAP and RAP savings estimates in an amount proportional to the percentage of load that has elected to opt out of efficiency programs.

IPL considered three different DSM bundling options. Option A involved creating the program potential or actual programs - each DSM bundle represented a program. Option B involved creating end-use bundles with similar load shapes that are further disaggregated into cost tiers. Option C used MAP to create bundles based on similar load shape end uses. IPL selected Option B because they thought the method allowed for more creativity in program creation. Also, the cost tiers prevent cost-effective measures from being eliminated because they are bundled with high cost measures, which could happen with Option C. MAP was used to construct the DSM bundle inputs into the IRP.

IPL worked with AEG and Morgan Marketing Partners to create DM bundles using the DSMore cost-effectiveness model. Energy efficiency measures within MAP were bundled by sector and technology to take advantage of load shape similarities among like measures. Bundles were further divided by the direct cost to implement per MWh: up to $30/MWh, $30-60/MWh, and $60+/MWh. IPL decided to use

[8] A MPS assesses how much DSM (energy efficiency and demand response) is potentially achievable in a utility system. A MPS is normally used to estimate the level of Technical Potential, Economic Potential, and Achievable Potential. Technical Potential is the maximum energy efficiency available, assuming that cost and market adoption of technologies are not a barrier. Economic Potential is the amount of energy efficiency that is cost effective, meaning the economic benefit outweighs the cost. Achievable Potential is the amount of energy efficiency that is cost effective and can be achieved given customer preferences.

$30/MWh as the top-end of the low cost tier because this is roughly the delivery cost for IPL's 2016 DSM portfolio. It was determined the maximum number of bundles the capacity expansion model could reasonably handle was around 45. To meet this model limitation, IPL decided to split the IRP timeframe into a near-term period that is consistent with its next DSM filing period (2018 to 2020) and a long-term period of 2021 to 2036.

DSM in the IRP capacity expansion model is compared to building new generation or purchasing power to meet load requirements. This is done by giving supply-side characteristics, including load reduction or load shape change potential, and levelized cost in $/MWh and $/MW to the DSM bundles.

2.3.1 Issues / Questions

IPL, despite using the same consultants as NIPSCO, modeled DSM slightly differently than NIPSCO and substantially different from Vectren. In fact, all three companies differed as to how they handled model limitations that constrain how DSM can be modeled in the IRP resource optimization model. For IPL, in dealing with the limitation on the number of resources that the capacity expansion model could handle, it appears IPL reduced the DSM decision points to two years, 2018 and 2021. In 2018, the level of DSM for 2018 to 2021 is chosen. In 2021, the level of DSM for 2021 to 2036 is decided. This is according to the explanation in Section 7.3.3 (page 147) of the IRP main document which reads as follows: "For example, let's say the model picks the Residential Lighting block for the 2021–2036 period. The level of DSM within this bundle is pre-set for this period based on the Market Potential Study. DSM within this bundle is static and will not increase in year 2030, if there is a need for additional capacity to meet the reserve margin." To the degree that this is the case, the treatment of DSM in the capacity expansion decision is not quite on par with the supply-side resources whose decisions are made annually in the capacity expansion model to ensure the resources satisfy the reserve margin requirements.

Another problem area for any utility is to project how DSM costs change over time. IPL's costs per bundle appear to be based on costs contained in the MPS. These costs include incremental measure costs (IMC) of installed DSM measures, which is the difference in cost of a base case measure compared to the cost of a higher efficiency alternative. Other costs that were included were incentive costs and administrative costs that cover vendor implementation costs, EM&V costs, and IPL's internal costs. The administrative costs for modeling purposes were assumed to be 20% of IMC. A measure with an IMC of $10.00 would have an administrative cost of $2.00. IPL assumed future DSM costs escalated by 2.0% annually.

2.4 Metrics for Preferred Plan Development

As noted by IPL in its previous IRPs, IPL primarily used the PVRR of scenarios to compare candidate portfolios. In the current IRP, IPL recognizes that PVRR is important but does not tell the entire story of a portfolio's outcomes. For the 2016 IRP, IPL expanded the number of quantitative metrics in addition to PVRR used to evaluate resource portfolios. IPL used metrics that fit into four categories: cost, financial risk, environmental stewardship, and resiliency. In response to stakeholder feedback, IPL added metrics to measure sulphur dioxide (SO_2) and nitrogen oxide (NO_X) emissions, the percentage of IPL's resources that is distributed generation, and IPL's planning reserves. The following table shows the four metric categories, the individual metrics, and the metric definitions.

Category	Metric	Unit	Definition
Cost	Present Value Revenue Requirements (PVRR)	$MM	The total plan cost (capital and operating) expressed as the present value of revenue requirements over the study period
	Incremental Rate Impact (over 5 years)	cents/kWh	The incremental impact to customer rates of adding new resources, shown in five year time blocks
	Average Rate Impact (over 20 years)	cents/kWh	The average 20 year cost impact of adding new resources divided by total kWh sold
Financial Risk	Risk Exposure	$	The difference between the PVRR at the 95th percentile of probability and the PVRR at 50% percentile probability (expected value)
Environmental Stewardship	Annual average CO_2 emissions	tons/year	The annual average tons of CO_2 emitted over the study period
	Annual average SO_2 emissions	tons/year	The annual average tons of SO_2 emitted over the study period
	Annual average NO_x emissions	tons/year	The annual average tons of NO_x emitted over the study period
	CO_2 intensity	tons/MWh	Total tons of CO_2 during the study period per MWh of generation during the study period
Resiliency	Planning Reserves as a percent of load forecast	%	Planning reserves are the MW of supply above peak forecast. This metric measures planning reserves as a percent of peak load forecast
	Distributed Energy Generation	%	Percent of IPL's resources that is distributed generation, shown in five year time blocks
	Market reliance energy	%	Percent of customer load met with market purchases
	Market reliance capacity	MW	Total MW of capacity purchased from MISO capacity auction to meet peak demand plus 15% reserve margin

According to the IRP, the metrics provide a comparison of how the candidate portfolios differ in terms of cost, financial risk, environmental stewardship, and resiliency. The metrics also show the trade-offs that must be considered when selecting a preferred resource portfolio.

When discussing the model results, IPL introduces a metric/measure that is not mentioned in Figures 7.14 or 7.15 in the metrics development section of the IRP. IPL notes that portfolio diversity is important to mitigate risk of fuel price variation and/or potential fuel shortages. From a cost-mitigation or reliability standpoint, it may not be wise to pursue a portfolio that heavily relies on one fuel (p. 159). The value of fuel and resource diversity is pivotal in this IRP, and it is likely to be a central issue in the future IRPs – perhaps THE central issue for several years. As a result, fuel and resource diversity warrant a much more expansive narrative.

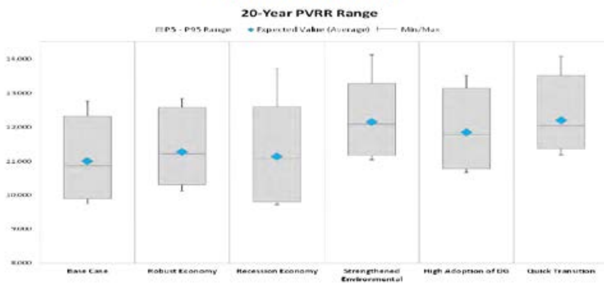
IPL also seems, at least initially, to make a distinction between the metrics used to evaluate and compare the resource portfolios listed above and the quantitative metrics used to review the stochastic analysis results, even though these latter metrics complement the other metrics. According to IPL, the stochastic analysis provides insight into how each portfolio performs against a range of futures. Each portfolio introduces risk by the nature of having varying mixes of resource types, so quantifying that risk and identifying the drivers of that risk helps guide the development of a preferred resource portfolio.

There are several useful metrics presented by IPL to review the stochastic analysis:

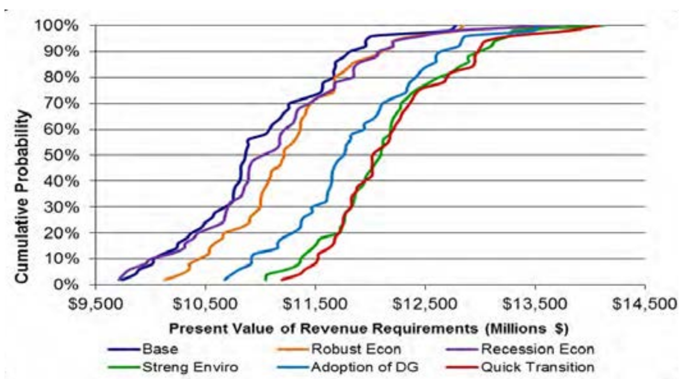
1. IRP Figure 8.35 (p. 184) "contains a summary of the range of PVRRs for each portfolio based on results from the stochastic model. The gray box represents the range of PVRRs between the

5th and 95th percentiles, which means that 90% of the PVRR outcomes fell in this range. The horizontal bar within that box is the 50th percentile or median value, and the blue diamond is the expected value or average of the outcomes. Two useful comparisons across the portfolios are the expected value and the height of the top of the 5th-95th box."

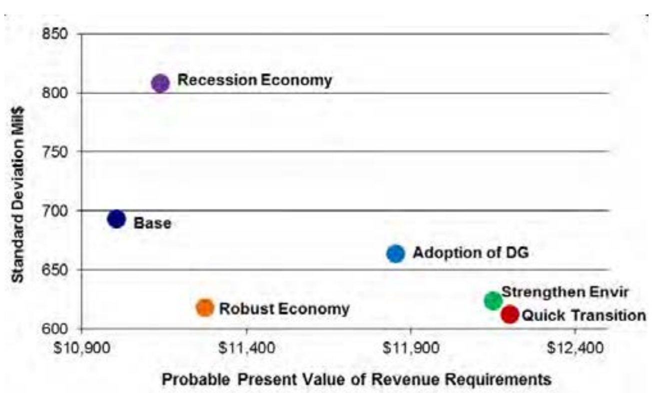
Figure 8.35 – PVRR Ranges



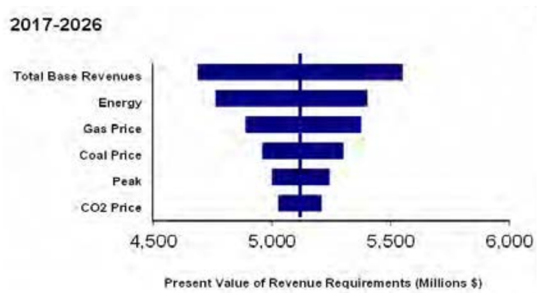
2. IRP Figure 8.36 (p.185), shown below, is a risk profile chart, or a cumulative probability chart. "The risk profile shows the distribution of PVRR outcomes from the fifty stochastic draws, showing the outcomes as the cumulative probability of each occurrence between 0% and 100%." The figure "contains the risk profiles for each portfolio, with PVRR along the X-axis and the cumulative probability on the Y-axis. For each line, the difference between the bottom left point and top right point on the line is the range which 100% of the outcomes are expected to fall." (p. 184)



3. IPL also uses a tradeoff diagram (Figure 8.37 on p.186) with the expected value of each portfolio against the standard deviation of the PVRR outcomes as another way to measure portfolio risk.



4. "An additional step IPL took was to identify the drivers of the risk by creating 'tornado charts' in 10-year periods for each portfolio. A tornado chart uses a regression analysis to measure changes in Total Base Revenues – the dependent variable – in response to changes in independent variables such as load, gas prices, coal prices, and carbon prices. The vertical line is the 'Expected Value,' and the 'Total Base Revenues' bar to the left and right of the Expected Value is the range of PVRRs for that scenario. The independent variables on the tornado chart are listed in order of their impact on the PVRR. For example, Figure 8.38 [shown below] shows that the load forecast, labeled 'energy,' has the highest impact on PVRR for the Base Case 2017-2026, and that CO_2 has the lowest impact. However, the changes to the PVRR are not cumulative through the independent variables: the sum of the independent variable horizontal bars will not equal the horizontal bars of the PVRR. Instead, the horizontal bars of the independent variables indicate the magnitude of change to the PVRR due to changes in one single variable." (p. 186)



In the Scenario Metrics Results section of the IRP report (pp. 193-206), IPL summarizes the results of eleven metrics in the four metrics categories. The metrics are further summarized in Figure 8.65 on page 206.

The stochastic analysis is used only in a limited manner in the Scenario Metrics Results section discussion. First, the Risk Profile chart for the Base Case is presented on page 196 but a better figure to use is Figure 8.36 on page 185, because information on the risk exposure of several scenario portfolios is presented in one place which makes for an easy comparison. The Director understands that the Risk Profile for the Base Case is presented to demonstrate how the difference between the expected value (the mean) and the 95th percentile probability is calculated, and that this is the metric IPL uses to evaluate the risk exposure of each portfolio in Figure 8.53 on page 197. This measure emphasizes the probability of higher costs relative to the expected value but also says nothing about the probability of lower costs. The Director believes consideration needs to be given to both the probability of both good and bad outcomes. This is the benefit of Figure 8.36 on page 185. It shows the probability of revenue requirements both above and below the expected value for each scenario portfolio and each scenario is on the same figure.

The Director believes greater use of the quantitative metrics used to evaluate the stochastic modeling results would have improved the comparison of the overall scenario metric results. The addition of the figures displaying the projected annual emissions of NOx and SO2 by scenario was a nice supplement to the metrics for the average annual SO2 and NOx emissions by scenario.

2.4.1 Portfolio Diversity

As noted above, IPL discusses a metric it calls portfolio diversity. IPL notes in the Model Results section that except for the Recession Economy and Strengthened Environmental scenarios, the scenarios result in a diverse portfolio of resources in 2036. Portfolio diversity is also explicitly presented by portfolio in several figures and discussed on pages 161-171. However, in the Scenario Metrics Results section, nothing is explicitly said about portfolio diversity. Perhaps this is because, as IPL mentioned, except for two portfolios, the remaining portfolios contain a diverse set of resources.

2.4.2 Resiliency

At the same time, one of the four metric categories used by IPL is resiliency, which they define as measuring customer exposure to price volatility and market reliance. IPL goes on to note that, "[b]y securing the required planning reserve margin requirement and limiting market reliance for capacity or energy, IPL and its customers can have a high level of resiliency." (p.202) It is clear that the concepts of portfolio diversity and resilience, as defined by IPL, are very similar but also different. It is unfortunate that IPL did not more clearly explore how each concept was interrelated. This would have added to a richer discussion of fuel and resource diversity.

IPL recognizes the risk of technological change and obsolescence in some metrics. One can argue that this is partially reflected in a couple of metrics (especially portfolio diversity) but more explicit discussion would have been helpful. IPL seems to recognize that some level of reliance on the market for both capacity and/or energy can be economic or risky but they do not seem to recognize that long-term resource acquisition embodied in both owned resources and Purchase Power Agreements (PPAs) represent their own forms of risk when all aspects of the electric utility world are changing rapidly and fundamentally.

IPL summarizes the metric results in Figure 8.65 (p. 206) as noted above but states the metrics are not meant to provide answers. Instead, they are meant to show the results in a way that will improve IPL's and stakeholders' understanding of each scenario, provide a comparison of each scenario, and allow IPL and stakeholders to ask questions and dig deeper into the results (p. 193). Despite the comments above, the Director believes the metrics developed and presented by IPL met this objective.

2.4.3 Assessment

IPL demonstrated a substantial improvement in the development and application of metrics to evaluate resource portfolios compared to the 2014 IRP. More importantly, IPL's 2016 IRP included a more explicit and extensive discussion of risks and uncertainties which were better connected to the metrics. The 2014 IRP had an emphasis on PVRR to evaluate alternative resource portfolios with minor recognition of annual air emissions of SO_2, NOx, and CO_2. The 2016 has an improved use of metrics to explore costs in various ways and includes a number of measures of resilience. The specific criticisms discussed above should not detract from the significant actions of IPL to better use more diverse metrics to evaluate resource portfolios.

3. NIPSCO

3.1 NIPSCO's Fuel and Commodity Price Analysis for 2016 IRP

Given the importance of fuel forecasts in retirement decisions that are a focal point of this IRP, it is surprising that NIPSCO only relied on one projection for fuel prices. The use of a single vendor forecast made the lack of a narrative to articulate the rationale for the forecast more problematic. The fuel forecast narrative is that the price of natural gas and coal is merely a function of demand. This seems to be an over-simplistic explanation to price forecasts for coal and natural gas.

While demand for natural gas and coal are likely to be important variables since much of the "fracking" [9]is for production of oil, it would seem that the production of oil should be a variable in projecting future natural gas prices.**[10]** Of course, oil prices and production in the United States is likely to be influenced by world-wide events. The export (or import) of Liquefied Natural Gas (LNG) might be an important variable, not just for the quantity but as a reference point for what it tells analysts about future price formation in the natural gas markets.

In the longer-term, NIPSCO should consider technological change in the production of oil, natural gas, and coal. Anecdotally, some coal companies may offer innovative prices that may increase the dark spread. However, the crucial test will be whether short-term coal prices can be sustainable over the longer term.

The CAC et al. raised a significant concern about NIPSCO's fuel and market-price forecasting. Hopefully to address concerns about transparency, analytical rigor, and credibility, these concerns can be minimized in future IRPs by starting the stakeholder process earlier and allowing stakeholders more involvement into the data, assumptions, development of scenarios, and sensitivities. CAC et al. wrote:

> *NIPSCO did not make data developed for it by PIRA available to stakeholders, including its emissions, power, and commodity price forecasts—despite the fact that CAC and Earthjustice have executed a Non-Disclosure Agreement with NIPSCO regarding exchange of confidential information utilized by the Company in its IRP analysis... In a phone call on February 27, 2017, NIPSCO staff* ***indicated that they do possess a narrative explaining and documenting PIRA's forecasts but they could not share it with CAC and Earthjustice. NIPSCO actions in withholding this information are antithetical to transparency and meaningful stakeholder participation****.[Emphasis added] In that same*

[9] Energy Information Administration, Drilling Productivity Report-Key tight oil and shale gas regions, June 2017.

[10] Prior to the development of shale gas, crude oil and natural gas prices tended to move together as they acted as substitutes for each other for various energy demands, such as space heating, electricity generation, and industrial processes. With the development of wet gas fields, that relationship has changed. The prices follow the same general trajectories, with the exceptions of the previously mentioned natural gas price spikes, until 2009, at which point they diverge. With the more moderate oil prices in the past couple years, the positive correlation of the two prices has returned. There appear to be two competing factors affecting the relationship between natural gas and oil prices. On the demand side, they act as substitutes for each other in various processes and end uses. Thus, an increase in oil prices results in an increase in natural gas demand and a corresponding increase in natural gas price. On the supply side, they are co-products in wet gas production. High oil prices spur increased drilling activity, which results in more natural gas supply and lower natural gas prices. From the onset of the shale boom until the drop in crude oil prices, the co-production effect was more significant and the price diverged. With lower oil prices, drilling activity is reduced and the demand substitution effect is more pronounced. The combined effect has been to keep natural gas prices relatively low and stable under both high and low oil prices. SUFG's update to the November 2013 report entitled *Natural Gas Market Study.*

> *call, NIPSCO staff stated that they did not know what the price setting unit was in their Base Case MISO power price forecast.*

The Indiana Coal Council expressed similar concerns and provided information that raised other concerns that NIPSCO's analysis of coal and natural gas price projections could be enhanced.

> *The outlook for natural gas supply, which is clearly the most important consideration in NIPSCO's IRP, is without any depth or context… Without discussion of the respective supply and demand for coal and natural gas, NIPSCO did not (and could not) provide the required discussion of risks and uncertainties for these sources of fuel, as required in the Draft Proposed Rule, §§ 4(23) and (8)(c)(8). More significantly, NIPSCO claims that it does not know what PIRA's assumptions were and PIRA provided no written documents to NIPSCO in support of the forecasts. This is highly unusual. If the forecasts are the consultant's standard forecast, they would come with accompanying assumptions. If the forecasts are customized to the client's request, which is often the case, the specific assumptions would be noted.…. By failing to instruct PIRA as to what assumptions should be assumed in the price forecasts, NIPSCO has no way of knowing whether the assumptions in the price forecasts are consistent with other parts of the IRP analysis. By failing to understand PIRA's assumptions vis-à-vis the price forecast, NIPSCO by definition cannot accept full responsibility for the content of the IRP because it claims no knowledge of what those assumptions are.* ICC pages 4-6 (1.11), (1.13), (1.21), (1.22), (1.23) and (1.24).

In conversations with NIPSCO staff, NIPSCO confirmed its belief that the primary driver of natural gas prices was the demand for natural gas. While this is a plausible theory, given the paradigm change in the natural gas markets, total reliance on changes in the demand for natural gas to dictate the price of natural gas seems problematic. Recent history has shown prices going down as demand for natural gas has increased, largely due to increases in oil production. For example, NIPSCO's assumption doesn't capture the nuanced and dynamic relationships between oil and natural gas markets or whether the historic correlations between natural gas and coal markets are changing. To the extent there are other possible explanations for the changing relationships between coal and natural gas prices, these other possible explanations did not influence the development of scenarios or sensitivities and, as a result, did not result in different portfolios that might have provided NIPSCO with additional valuable insights that might alter future plans.

NIPSCO's assumptions for future natural gas and coal prices led the Indiana Coal Council to observe, "[I]f the case assumed high gas prices, it also assumed high coal prices; if the case assumed low gas prices, it also assumed low coal prices. NIPSCO indicated this was the case because it used "correlated" commodity price assumptions. The term correlated was not specifically defined. Page 7 [2.2] and [2.3].

The Director agrees with the Indiana Coal Council that, "NIPSCO's use of a correlated price forecast between coal and gas prices is not explained." Page 10 [2.7].

While the Director agrees several of the comments of the Indiana Coal Council merit consideration by NIPSCO, according to NIPSCO, the ICC's concerns would not have changed the overall results of NIPSCO's IRP analysis.

The ultimate test is the economic dispatch of coal and natural gas generation in the Regional Transmission Organizations' (RTOs') markets. Over the 20-year planning horizon, NIPSCO recognized the need for *optionality* to provide an opportunity for mid-course corrections if the operations of coal-fired generation cover variable operating and fixed capital costs to permit retention and possible extension of the coal fleet. The *off ramps* that NIPSCO built in could allow for new clean coal technologies to be considered.

The importance of credible fuel price projections become increasingly important because future retirement decisions are likely to be increasingly close calls. Prudence dictates that credible and transparent analysis is essential for assessing reliability and cost ramifications.

3.2 Scenario and Risk Analysis

NIPSCO's construction of scenarios and sensitivities in the 2016-2017 IRP is a significant advancement over the 2014 IRP. The clarity of the narratives was commendable. The transparency throughout the IRP process afforded to stakeholders was exceptional. NIPSCO provided information that other utilities have not provided. We applaud this openness. To NIPSCO's credit, they were sensitive to the ramifications of these decisions on its employees, communities, and customers.

Resource optimization modeling included a reasonable amount of supply-side and demand-side options; portfolios associated with three planning strategies focusing on least cost, renewable and low carbon emissions, respectively, were identified for each scenario and sensitivity. Especially given what NIPSCO and others knew at the time the analysis was conducted about fuel cost projections and public policy, the analysis was credible. Results were presented in an informative way. However, like other utilities, NIPSCO performed much of the retirement analysis prior to the resource optimization. NIPSCO recognized the modeling limitations and said it intends to procure modeling software that is better able to simultaneously optimize more resources and reduce the reliance on pre-processing important decisions. NIPSCO contended that its Preferred Portfolio "*aligned with NIPSCO's reliability, compliance, diversity, and flexibility criteria; it almost always had lower costs to customers across the scenarios*." [Page 159].

3.2.1 Models, Drivers, and Scenarios

NIPSCO used the ANN Strategist Proview Capacity Expansion Model to perform the optimization on three portfolios including a least cost portfolio, a renewable portfolio, and a low emissions portfolio (Page 32 of the IRP). The resource alternatives included in this IRP cover 26 demand-side and about 20 supply-side options. Each resource option was individually and fully selectable during each optimization run. The objective of the model is to minimize the Net Present Value of Revenue Requirements (NPVRR).

The first step NIPSCO used in developing the 2016 IRP scenarios was to identify key drivers that could potentially affect its business environment. Then seven long-term commodity pricing cases were developed for the Strategist planning model, taking into consideration the correlations between economic condition, load growth, environmental policy, fuel prices and carbon cost. Those fundamental commodity prices serve as key assumptions for various scenarios in the analysis.

Five scenarios were developed by NIPSCO using different datasets that correspond to specific future worlds. The five scenarios were:

1. Base (B),
2. Challenged Economy (CE),
3. Aggressive Environmental Regulation (AE),
4. Booming Economy (BE), and
5. Base Delayed Carbon (BDC).

Then, a number of sensitivities were developed for each scenario by modifying a single variable each time to analyze the effects of a specific risk on the corresponding scenario. Although each sensitivity focused on a single risk, other related input data were changed accordingly. There were 10 sensitivities in total. In general, NIPSCO did a good job of setting up a comprehensive framework to capture possible futures and address various risk factors. However, there are some inconsistencies in the IRP report regarding the definition of scenarios, which are addressed in detail in the next section.

A separate retirement analysis was conducted before system-wide optimization was performed to identify the future resource mix. Based on the environmental compliance dates and the associated costs to run the existing coal-fired generation units, six retirement portfolios were developed. A combined cycle gas turbine (CCGT) was selected as a proxy for the replacement alternative because of its favorable levelized cost of energy, reliability, dispatchability, and straightforwardness to plan, permit and build. The six retirement portfolios were evaluated across all scenarios and sensitivities and were ranked based on the NPVRR. In addition, the ability of each portfolio to meet Clean Power Plan Compliance Targets, fuel and technology diversity, as well as community impact were considered during portfolio evaluation. A retirement portfolio without any significant difficulties or hurdles for each one of the evaluated criteria was selected as the preferred retirement option. Based on the retirement analysis, NIPSCO's preferred retirement plan is to accelerate the retirement of Bailly Units 7 and 8 and Schahfer Units 17 and 18 and to move forward with compliance investments for its remaining coal units. The entire retirement methodology sounds reasonable. However, some explanations of retirement portfolio design might be necessary to help audiences understand why some older units were set to run to the end of life but some younger units were set to retire soon in a few retirement portfolios to be evaluated. In the seventh page of the Executive Summary, a table lists ages of various coal units owned by NIPSCO. Based on ages shown in the table, Schahfer 17 and 18 are younger than Schahfer 14 and 15. In addition, all Schahfer units are younger than Michigan City. However, for Combination 4 displayed in Table 8-3, which was also the combination chosen as the preferred retirement option after evaluation, Schahfer 17 and 18 were set to retire in 2023, while Schahfer 14 and 15 are set to run to the end of life. In Combination 5, Michigan City was set to run to the end of life, while all Schahfer units were set to retire in 2023.

Results were presented in a clear and logical way. For each scenario, capacity portfolios under the three planning strategies (Least Cost, Renewable Focus and Low Emission) were identified. Numbers of selected resources were listed by technology for each portfolio. Trajectories of annual carbon emissions were depicted by portfolio as well. In addition, energy mixes by planning strategy and scenario were summarized and compared with each other. Summary of NPVRR and DSM selection across the various scenarios and sensitives were provided. A preferred portfolio for the next 20 years was derived from analysis results based on a number of criteria, including providing affordable, flexible, diverse and reliable power to customers while considering the impact to environment, employment and the local economy. In addition, DSM groupings were broken into four categories according to the time of selection across various scenarios and sensitives, providing the basis upon which NIPSCO's 2017 DSM Plan would be determined.

3.2.2 Issues / Questions

In section 8.1.2 titled Fundamental Commodity Prices, descriptions about various commodity cases make sense but seemed to be too simplistic. As discussed in the Fuel and Commodity Price Projections section (e.g., page 15) of this Draft Director's Report, the drivers for the production and price of natural gas and coal seems likely to be more complex than simply the demand for natural gas and coal. However, figures illustrating the long-term projections of the major commodities lacked explanations, which detracted from the explanatory value of the descriptions. The following are some examples.

1. For coal prices in Figure 8-4 on p. 118 and Figure 8-5 on p. 119, the Very High case has a price decrease in the 2022 to 2024 timeframe. Explanations about the driving forces for those outcomes are not obvious and would benefit from a discussion.
2. In Figures 8-7 and 8-8 on p. 120, the on-peak and off-peak power prices show step increases in 2024 in the Base, Low and High cases. As described in scenarios, the carbon price comes into effect in 2023. Why were sudden increases in power prices observed in 2024?
3. Figure 8-9 on p. 121 shows capacity price in \$/kW-YR. The specific resource technology is not clear. Is it average capacity price across different technologies? How do capacity price projections shown in the graph correlate with the various commodity pricing cases? A detailed description might need to be added to the report to help the audiences understand the information presented in the graph.

In addition, there seem to be inconsistencies in the description of scenarios presented in different sections of the report.

1. In the Base Scenario Assumptions shown in p. 122, the report mentions that "The average price of Powder River Basin coal is slightly above \$1.00/MMbtu by 2035." However, in the coal price trajectories shown in Figure 8-4 in p. 118, no trajectory matches this description. The one closest would be the Base coal price trajectory, but coal price in that trajectory is no more than \$1.00/MMbtu in 2035 based on observation. In addition, assumptions about Powder River basin coal price and Illinois Basin coal price were not presented in Table 8-1: Scenarios and Sensitives Variable Descriptions on p. 130. Therefore, there is no way to know exactly which coal price assumption was used for various scenarios and sensitivities.
2. In the Challenged Economy Scenario Assumptions shown on p. 123, it is less clear which Powder River Basin coal trajectory was used in this scenario. In addition, the carbon price increase in 2023 mentioned in the description does not seem to be consistent with the information presented in Figure 8-7 and Figure 8-8.
3. In the Aggressive Environmental Regulation Scenario Assumptions shown on p. 124, the report mentions that "Energy load is increasing at 0.68% and peak demand is increasing at 0.80% (CAGR 2016-2037) annually over the study period." This same load assumption is shown in the Booming Economy Scenario Assumptions at the bottom of p. 124. However, in Table 8-1: Scenarios and Sensitivities Variable Descriptions, "Base Load" is shown for the Aggressive Environmental Regulation Scenario and "High Load" is shown for the Booming Economy Scenario in NIPSCO's explanation.
4. In the Booming Economy Scenario Assumptions shown in the beginning of p. 125, the report mentions that "A national carbon price comes into effect in 2023 (\$13.50/ton nominal increasing to \$38/ton in 2035)." Table 8-1 on p. 130 shows Base carbon price trajectory for this scenario. However, in Figure 8-6: CO_2 prices shown on p. 119, no trajectory matches the description about carbon prices in the Booming Economy Scenario on p. 125.

There are also some concerns about the DSM modeling mentioned on p. 142. As NIPSCO recognized, due to the inability of Strategist to optimize all 26 DSM groups simultaneously, the demand-side programs were broken down into the various end uses (residential, commercial and industrial) and optimized against an array of supply-side options. One shortcoming of this modeling methodology is a lack of competition among DSM groups of different end-uses, which is highly likely to lead to a portfolio different from modeling all 26 DSM groups simultaneously. Moreover, with the increase in peak demand relative to energy use, it would seem there are opportunities for more demand response that were not modeled. In part, the failure to more comprehensively optimize DSM and to optimize DSM with other resources seems to be a limitation of its current model and should be ameliorated by future models.

In Figure 8-31 on p. 159 the NPVRR for the preferred portfolio appears to be slightly smaller than the NPVRR for the least cost optimal solution, which is not feasible.

Finally, it seems that no scenario or sensitivity covered uncertainties of resource technology cost. Based on information provided at the August stakeholder workshop, capital costs for all technologies increase in nominal dollars at the same rate, based on proprietary consultant information. The reasonability of this is questionable considering that some technologies are less mature commercially (e.g., battery storage) than others.

The Director largely agrees with NIPSCO and its characterization of concerns raised by stakeholders regarding NIPSCO's consideration of retirements of some coal-fired generating units, the dynamics of the natural gas price projections being the primary driver, and NIPSCO's use of Cost of New Entry (CONE) merely as a proxy for the cost of new resources (see below quote).[11] However, the Director is confident that NIPSCO would agree with stakeholders that future IRPs will have to be increasingly rigorous as credible decisions are increasingly difficult and impactful.

> *The Industrial Group and ICC argued that NIPSCO was too aggressive in retiring the four units, while other stakeholders argued that NIPSCO should retire 100% of its coal fired generation almost immediately. NIPSCO endeavors to ensure that a reliable, compliant, flexible, diverse and affordable supply is available to meet customer needs, and its IRP demonstrates that it does just that. In the retirement analysis, the costs and benefits of continuing to operate the NIPSCO units, including the dispatch costs, recovery, maintenance, retrofitting and continuing to operate the affected units with the appropriate effluent limitation guidelines ("ELG") and coal combustion residuals ("CCR") compliance technologies were compared to costs and benefits of retiring and replacing the units with an alternative. The alternative, CONE, was used for retirement analysis only and was not NIPSCO's selection, but intended to be a conservative proxy for what could be readily built or purchased in the market. This analysis was evaluated across the 15 scenarios and sensitivities discussed with all the stakeholders throughout NIPSCO's 2016 IRP process.*
>
> *While cost to customers is a key decision driver, the decision to retire the four units took into account a variety of factors in addition to customer economics, which caused it to be a "preferred" choice for customers from the Company's standpoint. It is important to highlight that the model showed a lowest cost path of retiring 100% of coal which was not selected as the "preferred" path given these other factors.*
>
> *Even with ICC's comments regarding coal availability and pricing, the analysis would not change dramatically regarding the appropriateness to retire Units 7/8 and 17/18. There must be a balance among continued investment in operations and maintenance ("O&M"), maintenance capital, and maintaining the option to keep Units 17/18 open. However, key*

[11] Response Comments of Northern Indiana Public Service Company to Stakeholder Comments on NIPSCO's 2016 Integrated Resource Plan submitted April 28, 2017, pages 8 and 9.

variables such as environmental regulations can change over time and therefore NIPSCO will evaluate the value of developing a compliance option at Units 17/18 as part of its next IRP. It is important to remember that fuel and technology diversity is important as over-reliance on a single fuel-source may leave a utility and its customers unnecessarily exposed to various operational and financial risks from fuel supply disruptions and/or price volatility. Fuel and technology was quantified by the capacity mix by the end of the planning period.

Despite claims to the contrary, NIPSCO considered long-term gas forecasts in its retirement modeling, but NIPSCO's believes gas prices would need to rise dramatically and stay at a sustained high price to make it economical to continue to operate the units proposed for retirement. This, coupled with the correlated coal forecast, indicates that NIPSCO's Retirement Analysis is appropriate.

Additionally, there were concerns that NIPSCO's retirement path did not consider potential future changes to the ELG. NIPSCO believes that United States Environmental Protection Agency's ("EPA's") ELG rule is consistent with the requirements under the Clean Water Act. The ELG rule is a final rule, and NIPSCO has a responsibility to include it in future resource planning. Although it is possible that there may be changes to the rule which could affect compliance requirements, any changes would be speculative at this time.[12] *If changes to the final ELG rule are propagated, NIPSCO will include and consider any changes in future resource planning.*

Although the IRP is not required to consider factors such as whether or not NIPSCO attempted to sell units it is planning to retire, it does consider if the utility can meet its resource requirements. NIPSCO's IRP meets that standard. In addition, NIPSCO has done an assessment of the market value of the retiring units, and contrary to the ICC's assertions, NIPSCO has been willing to engage with parties interested in purchasing the retiring units.

3.3 Energy Efficiency

It should be noted that NIPSCO's DSM methodology is very similar to that used by IPL. In fact, they both used the same consultants – AEG to prepare a Market Potential Study (MPS) and Morgan Marketing Partners (MMP) to develop the Program Potential based on the MPS and to complete the overall benefit cost results based on the program potential as determined by the MPS.[13]

AEG estimated the technical, economic, and achievable potential at the measure level for energy efficiency and demand response within NIPSCO's service territory over the 2016 to 2036 planning horizon. MMP

[12] NIPSCO recognizes that the U.S. EPA Administrator announced on April 17, 2017, that the EPA issued an administrative stay of outstanding compliance deadlines for ELG and was also petitioning the U.S. Court of Appeals for the 5th Circuit to hold litigation challenging the final ELG rule in abeyance until September 12, 2017. The 2016 IRP was a point-in-time forecast completed in November 2016. Any impacts from the EPA's actions will be addressed in the next IRP.

[13] A MPS assesses how much DSM (energy efficiency and demand response) is potentially achievable in a utility system. A MPS is normally used to estimate the level of Technical Potential, Economic Potential, and Achievable Potential. Technical Potential is the maximum energy efficiency available, assuming that cost and market adoption of technologies are not a barrier. Economic Potential is the amount of energy efficiency that is cost effective, meaning the economic benefit outweighs the cost. Achievable Potential is the amount of energy efficiency that is cost effective and can be achieved given customer preferences.

used the measure-level savings estimates to develop the program potential. The program potential includes budget and impact estimates for the measures. The final budgets and impacts were then run through cost-effectiveness modeling using the DSMore tool to finalize the cost-effective program savings potential. The program potential step also includes information from NIPSCO's 2014 Evaluation, Measurement, and Verification (EM&V) report and applies that information to the Achievable Potential savings amount.

After the savings potential estimation process, the measures were bundled into DSM groupings. A grouping is defined as a bundle of measures with similar load shapes and end uses. Grouping measures by similar load shapes, end-uses, and customer segment (class) allows the IRP model to analyze large groups of measures more efficiently. NIPSCO elected not to further define its groupings by costs per kWh.

Due to a limit on the number of resource options that can be optimized simultaneously in the IRP model, the DSM program groupings were modeled sequentially by customer class (residential, commercial, and industrial). NIPSCO believes the sequentially optimization is comparable to a simultaneous co-optimization of all DSM programs.

3.3.1 Issues / Questions

NIPSCO made a number of improvements to its DSM analysis and the written description of this analysis in the IRP, and the information presented at the public advisory meetings was a very good improvement over prior IRPs. Nevertheless, improvement is an ongoing process as we all learn through experience. For example, NIPSCO also faced model limitations similar to that experienced by IPL and Vectren but chose a different work around. NIPSCO modeled DSM bundles sequentially; meaning that first residential bundles were optimized compared to supply-side resource options, then commercial sector bundles were optimized compared to supply-side options, and lastly industrial DSM options were optimized. Then NIPSCO generally put in the optimization model those residential, commercial, and industrial bundles that were selected in the sequential optimization. It is not clear if the selected combination of residential, commercial, and industrial DSM was locked in as a package in the optimization process or not. If the combined DSM groupings were locked in for the final supply-side optimization, then it could imply that the DSM groupings are not getting quite the same treatment as the supply side resources which are all included together in each scenario run.

NIPSCO discusses program grouping and portfolio budgets but it is not clear if its methodology for development of bundle costs differs much from that used by IPL. NIPSCO developed bundle costs in line with historic program cost allocations across the different budget categories. Each program grouping or bundle budget included categories for administration, implementation, incentives, and other. Administrative costs include NIPSCO staffing costs, planning and consulting costs, and EM&V costs. The "Other" category includes items such as low income measures which are paid by the utility but not classified as an incentive according to the California Standard Practice Manual. "Other" also includes some additional implementation costs for measures with very low incremental costs to include them in the portfolio. However, it is not clear how DSM bundle costs changed over time.

3.4 Metrics for Preferred Plan Development

NIPSCO's stated intent (p.3) is to develop a Preferred Plan that "follows a diverse and flexible supply strategy, with a mix of market purchases and different low fixed-cost generation types, to provide the best balanced mitigation against customer, technology and market risks." NIPSCO sees customer risk from the large concentration of load from its five largest customers. Approximately 40% of NIPSCO's energy demand and approximately 1,200 MW of peak load plus reserves meets the needs of these five customers. Loss of one or more of these customers would result in a significant decline in billing revenues.

NIPSCO defines technology risk as two separate risks from the perspective of a regulated utility.

Technology risks play a role in inducing market volatility, and they also have the potential to erode the value of existing assets. Technology changes drive a portion (but by no means all) of the volatility in market prices, both for capacity and energy. To the extent that a utility or its customers are exposed to market risk in general, they are exposed to this aspect of technology risk. Separately, technological and regulatory changes can render specific generation technologies obsolete and can force their premature retirement, such as is currently happening to coal generation. In its report, NIPSCO states:

…Fully avoiding technological obsolescence risk requires avoiding investing in generation, which exposes the utility and its customers to market risk. Investing in generation mitigates or eliminates market risk but exposes the utility and its customers to some amount of technological obsolescence risk.…Balancing these two risks in light of the technology choices available is key to mitigating overall supply portfolio risk. (p. 4)

NIPSCO continues by stating (p. 154) an important component of its supply strategy for the next 20 years is to reduce customer's and the company's exposure to customer load, market, and technology risks by intentionally allocating a portion of the portfolio to shorter duration supply. Another component is to strongly consider cost to customers, while considering all technologies and fuels as viable to provide shorter duration supply. (p. 155)

3.4.1 Retirement Analysis Metrics

NIPSCO's use of metrics to develop its Preferred Plan is applied to two different stages during the planning process, at the retirement planning stage and the optimization stage. The metrics appear to be the same across the two stages. For the retirement analysis, the six retirement portfolios were evaluated across all scenarios and sensitivities for a total of 90 optimization runs. Each model run was limited to the selection of a combined cycle gas turbine (CCGT) as a proxy. In all comparison analyses, the costs of the replacement unit was scaled on a megawatt basis to the same generating capacity as the existing unit by using a replacement capacity value of the CCGT.

Results for the six retirement scenarios were ranked from 1 to 6 with 1 being the portfolio having the lowest cost to customers or net present value of revenue requirement (NPVRR) and 6 having the highest. Figure 8-16 on page 137 of NIPSCO's IRP shows the NPVRR of the base scenario overlaid with range of NPVRR from all the scenarios and sensitivities. NIPSCO noted the magnitude of NPVRR changes depending on the specific scenario or sensitivity but the relative rankings of the retirement combinations generally remain the same within each scenario or sensitivity.

Retirement options under the Base scenario were analyzed to estimate their potential to meet Clean Power Plan compliance targets as shown in Figure 8-17 on page 138. Three of the six retirement combinations did not meet the CPP targets. Each retirement combination under the Base Scenario was also analyzed to show the diversity of each retirement combination. Portfolio diversity was measured as a percentage of forecast installed capacity in 2025. For example, a retirement combination portfolio might consist of 36% coal, 21% natural gas, 14% DSM, 3% renewables, and 26% other resources. Lastly, NIPSCO created a scorecard to show relative differences between the retirement portfolios using a number of quantitative and qualitative measures. The measures are NPVRR, Portfolio Diversity, Impact on Employees, Impact on

Communities and Local Economy, and Environmental Compliance. The scorecard used red, green, or yellow to show how each retirement combination was graded on each of the five measures. A red measure is viewed as worse, a yellow is better, and a green measure is viewed as good.

While recognizing that developing a "score card" to assess the relative importance of different metrics is a relatively new approach in the IRPs, it is not clear how the different measures are weighted in the score card. The score card would benefit from a more detailed narrative to detail those metrics that can be quantified as well as those metrics that do not lend themselves to quantification. For example, is NPVRR more important than the impact on the local economy? If yes, by how much and why? Also, the measure of portfolio diversity is based on installed capacity but might not a better measure be energy? At a minimum, the percentage of energy by fuel type and technology should have been considered. Also, the diversity consideration is limited since a significant resource "need" is shown in five of the retirement combinations but it is unspecified as to the type of resource. The way the retirement analyses were performed, CCGT capacity served as a proxy for other resources the model might have selected if given the opportunity. As noted by the CAC et al., the presentation of a retirement combination scorecard (p. 140 NIPSCO IRP) is qualitative and something of a *black box*. (p. 46 CAC comments on NIPSCO IRP)

3.4.2 Optimization Metrics

In the resource optimization modeling, NIPSCO broke down the DSM resources into residential, commercial, and industrial groups and sequentially modeled each group against an array of supply-side resources. This process was repeated for all 15 scenarios and sensitivities. NIPSCO developed a DSM plan based on these modeling results which was then used to evaluate the supply-side resources. NIPSCO utilized three planning strategies/portfolios, namely least cost, renewable focus, and low emissions portfolios across all scenarios and sensitivities. For the least-cost portfolio the model assessed all supply-side alternatives to develop a least cost plan. The model assessed a renewable focus portfolio by constraining the amount of fossil generation and increasing the amount of renewables. A low emissions portfolio was evaluated where the incremental amount of fossil generation and renewables was constrained to allow other low or non-emitting resources such as nuclear and batteries to be selected.

For each scenario the number of selected resources for each of the three strategies was listed by technology in tables. The trajectory of annual carbon emissions by scenario for each of the three strategies was compared. The cumulative 2015 to 2037 energy mix was also compared by scenario for each strategy. Lastly, the NPVRR by scenario and sensitivities was compared for each of the three portfolios.

NIPSCO notes on page 158 of its plan that it used a number of criteria to evaluate and select its Preferred Plan and that economics played a significant role. However, as noted by the CAC et al., it is not at all clear where the Preferred Plan came from or how it was determined. Nor is it clear how the various metrics were used. All that we can tell is that NIPSCO says it emphasized economics and that it used information provided by other metrics; but we can say little more. It is a problem when NIPSCO develops a Preferred Plan but the connection between this plan and the preceding analyses is murky at best. This should be addressed in the narrative.

Information is poorly presented regarding the components of the Preferred Portfolio such that a reader can read the entire IRP and not have a clear picture of the Preferred Portfolio. For example, Table 8-21 (p. 158) presents the assets retired and added by year over the forecast period. But there are no units of measure to tell the reader, for example, how much DSM is acquired in 2023. The same criticism can be made with regard to purchases. The lack of basic information about the Preferred Plan, combined with the poor discussion relating the Preferred Plan to the IRP's analyses and metrics, makes any evaluation of the Preferred Portfolio problematic at best. Overall, the IRP would have benefited from having one location where each metric was defined and was clearly stated how these metrics, individually or as a group, addressed the three key risks identified by NIPSCO – customer, technology and market risks. The narratives for each of the metrics need to clearly tie back to the important risks on which presumably the company based its IRP.

It is important to note that NIPSCO's planning model is not capable of stochastic analyses so it relied on scenario analyses and sensitivity analyses in preparing its IRP. The result was that NIPSCO's IRP analyses and methodology differed considerably from that presented by Vectren and IPL, both of whom did perform a stochastic analysis in addition to scenario analyses. To be clear, the Director believes stochastic analyses is not a substitute for scenario analyses; rather, they are complements that provide different information which can be combined to hopefully make better resource decisions. The result is that NIPSCO's metrics to compare resource portfolios necessarily differed in several ways from the type of metrics utilized by IPL and Vectren. NIPSCO recognizes this modeling limitation and, to its credit, is in the process of evaluating options to improve its modeling capability.

3.4.3 Assessment

The circumstances NIPSCO encountered developing the 2016 IRP differed considerably from those for the 2014 IRP. As a result, NIPSCO had a much more thorough discussion of risks and uncertainties and various metrics used to evaluate how the different resource portfolios might perform given the future is unknown. The previous IRP had almost exclusive reliance on PVRR to compare the portfolios. That is not to say there was no recognition of other factors, but the discussion of these other factors was much less developed. NIPSCO explicitly included in the 2016 IRP metrics covering portfolio performance in the areas of portfolio diversity, impact on employees, impact on communities and the local economy, and environmental compliance. The various questions or issues discussed above are not meant to detract from the substantial improvement seen when comparing the 2014 and 2016 IRPs.

4. VECTREN

4.1. Vectren's Fuel and Commodity Price Analysis for 2016 IRP

Vectren's consideration of multiple fuel price forecasts is very commendable and appropriate given the importance of the decisions that Vectren faces. On Page 74, Vectren said it relied on an averaging of forecasts from several sources[14] to form a consensus forecast for natural gas, coal, and carbon. This single averaged forecast for all commodities constituted the base forecast. Vectren also constructed alternative commodity price forecasts that were phased in relative to the base forecast. So near-term, a natural gas price was limited to a fairly small deviation from the base forecast, and the difference could grow in the medium-term and more so in the long-term.

We understand Vectren considered averaging of higher and lower forecasts but felt that was problematic due to different assumptions and different planning horizons. We will defer to Vectren's professional judgment but hope future IRPs will make use of lower and higher forecasts to provide a more complete scenario analysis. On p. 194 of its IRP report, Vectren describes how stochastic distributions of each of the key variables were developed, with select values that are either one standard deviation above or below the base case values for the variable.

The Director agrees with Vectren that the phasing in of an increasing range of commodity forecasts is appropriate going from the short-, to mid-, and to longer-term projections to capture most expected risks. However, to better understand the risks there is concern that reliance on just one standard deviation that only captures approximately 68% of the expected variation around the mean (expected value) is more appropriate for short-term fuel price forecasts, while for forecasts beyond five years (or so), a wider range of forecasts is appropriate. Two standard deviations to capture about 95% of the expected variation around the mean would seem more appropriate to gain insights on the potential risks of low probability events that are very consequential. As Vectren aptly describes "*stochastic distributions that reflect a combination of historical data and informed judgment tend to capture 'black swan events' that are impossible to forecast but tend to occur quite frequently*." [Page 194].

Consistent with the previous comment, the Director agrees with the ICC that a higher natural gas price case might have provided useful information. A narrative that is based on widespread anti-fracking policies might provide a plausible, even if unlikely case (note, in Vectren's "High Regulatory" scenario there was at least some reduction in gas supply growth and increased cost due to restrictions on fracking – Page 183). That is, a broad fracking ban is a low probability event that could result in significant price increases for natural gas if realized. Similarly, with new oil and gas assessments upgraded by the U.S. Geological Survey in the Permian Basin just after Vectren submitted its IRP, a lower natural gas price case might also be warranted. However, given Vectren's considerable expertise in natural gas by virtue of being a combination utility, some deference is reasonably accorded.

The Director appreciates the ICC's review of Vectren's IRP but disagrees that "*Vectren's failure to include scenarios without the CPPs (Clean Power Plan) is a serious flaw of its analysis*." The ICC would seem to hold Vectren to an untenably high requirement to integrate new information rather than the intention of the IRP to be a *snap shot in time* based on reasonable assumptions and empirical information at the time the

[14] For natural gas and coal, 2016 spring forecasts from Ventyx, Wood Mackenzie, EVA, and PIRA are averaged. For carbon, forecasts from Pace Global, PIRA, and Wood Mackenzie were averaged.

IRP was being developed. While speculation about changes in environmental policies are interesting, the still-unfolding changes in environmental policy are well outside the snap shot in time that Vectren was required to comply with by the draft IRP Rule. This is why the IRPs are done periodically to capture established and emerging trends.

Similarly, because the modeling process takes place over several weeks – perhaps months - the Director would not require Vectren to reconsider projections of natural gas prices based on the U.S. Geological Survey's news release on November 16, 2016 of a massive natural gas potential in the Permian Basin[15] which was before Vectren submitted their IRP which might further reduce the use of coal. Moreover, the ICC noted that the start of Vectren's analysis of the potential ramifications of the CPP didn't occur until the 2021 to 2026 time frame. In the Director's opinion, it was appropriate for Vectren to give some effect to the CPP based on the best information available at the time it was conducting its analysis. Additionally, it is conceivable that some form of CO_2 regulation may occur in the 2021 to 2026 time frame. Regardless of the specific facts that the ICC raised, it is important to memorialize the chronology of events to ensure that Vectren's planning processes were not misconstrued to be deficient regarding the information used in its IRP analysis.

More broadly, the ICC raises an issue that is applicable to all Indiana utilities – specifically, under what conditions should a utility update an IRP in response to significant events or changes in assumptions to important drivers? Nevertheless, it is important to keep in mind the Northwest Power Planning Council principle for its planning process that there are "no facts about the future."

4.2 Scenario and Risk Analysis

Vectren's analysis and processes improved significantly over its last IRP due to the immediacy of some decisions as well as providing for flexibility in making significant longer-term decisions over the next 10 to 20 years. The context for this round of IRPs included concerns about the potential loss of significant customers, largely unforeseen changes in the Clean Power Plan, low natural gas price forecasts relative to coal prices, and a precipitous drop in the price of renewable resources, highlight the need to regard IRPs—as Vectren observed—as a *compass* rather than a commitment to a specific resource strategy. Therefore, as Vectren correctly noted, the IRPs must be resilient to allow for mid-course adjustments in the plan. On page 50 and 51, Vectren articulates its integrated resource planning objectives:

- Maintain reliability
- Minimize rate/cost to customers

[15] November 16, 2016 **USGS Estimates 20 Billion Barrels of Oil in Texas' Wolfcamp Shale Formation.** This is the largest estimate of continuous oil that USGS has ever assessed in the United States. The Wolfcamp shale in the Midland Basin portion of Texas' Permian Basin province contains an estimated mean **of** 20 billion barrels of oil, **16 trillion cubic feet of associated natural gas,** and 1.6 billion barrels of natural gas liquids**.** The estimate of continuous oil in the Midland Basin Wolfcamp shale assessment is nearly three times larger than that of the 2013 USGS Bakken-Three Forks resource assessment, making this the largest estimated continuous oil accumulation that USGS has assessed in the United States to date."*The fact that this is the largest assessment of continuous oil we have ever done just goes to show that, even in areas that have produced billions of barrels of oil, there is still the potential to find billions more*," said Walter Guidroz, program coordinator for the USGS Energy Resources Program. "*Changes in technology and industry practices can have significant effects on what resources are technically recoverable, and that's why we continue to perform resource assessments throughout the United States and the world*."[Emphasis Added].

- Mitigate risk to Vectren customers and shareholders
- Provide environmentally acceptable power leading to a lower carbon future
- Include a balanced mix of energy resources
- Minimize negative economic impact to the communities that Vectren serves

The changing environmental regulations warrant emphasis, not only because of the potential effects on the utility's resource decisions, but also because they highlight an inherent difficulty in developing public policy assumptions in IRP modeling. That is, what is the probability of changes in public policy? The question highlights the need to interject more diverse scenario analysis into the IRP process since scenarios and sensitivities are more suitable for addressing the possible ramifications of changes in public policy. Moreover, it adds to the rationale for maintaining maximum optionality. As Vectren stated:

> *While future carbon regulations are less certain than prior to the election, it is likely that new administrations will continue to pursue a long term lower carbon future. SIGECO's preferred portfolio positions the company to meet that expectation. (p. 47)*

> *Several developments have occurred since the last IRP was submitted in 2014, which helps to illustrate the dynamic nature of integrated resource planning. The IRP analysis and subsequent write up represent the best available information for a point in time. The following sections discuss some of the major changes that have occurred over the last two years. The robust risk analysis recognizes that conditions will change. Changes over the last few years provided SIGECO with valuable insight on how modeled scenario outcomes can change over time. (p. 52)*

In the Preferred Portfolio *(*beginning on page 33 see also page 44), Vectren mentions greater reliance on energy efficiency, the possible addition of a combined cycle gas turbine in 2024, and solar power plants (2018 and 2019). Vectren's Preferred Portfolio also contemplates the potential retirement of Bags natural gas unit 1 (in 2018) and unit 2 (2025), Northeast Units 1 and 2 (natural gas) in 2019, Brown coal-fired units 1 and 2 (2024), FB Culley Unit 2 (2024), exiting joint operations at Warrick 4 (2020), and upgrade at Culley 3 for compliance with National Effluent Limitation Guidelines (ELG) and Coal Combustion Residuals (CCR). Vectren noted the ELG/CCR, which it characterized as the main drivers of closing Vectren coal plants, will be much more difficult to change than the Clean Power Plan (CPP). However, this potential Preferred Plan would significantly reduce Vectren's reliance on coal and result in a significant reduction in CO_2 emissions.

Similarly, Vectren's request for a short delay in the submittal of its IRP in order to better understand the potential implications of ALCOA's decisions is an example of good planning practice, especially given the importance of ALCOA to the Vectren system. To accentuate the importance of ALCOA, Vectren noted on page 203 that "*Under all scenarios, additional resources were not selected until joint operations cease at Warrick 4, causing a planning reserve margin shortfall*." However, given the importance of Warrick to Vectren's resource adequacy and since Vectren did not know the status of ALCOA at the time the IRP was prepared, it would seem reasonable for Vectren to have run at least one scenario that retained the Warrick 4 unit.

The narratives for the scenarios were well reasoned and clear. For the 2016-2017 IRP, Vectren developed its Base Case (not the Preferred Case) predicated on what Vectren considered to be the most likely future at the time this IRP was being developed. This included pre-processing analysis of the retirement of some of their coal-fired generating units to reduce the complexity of the modeling analysis. Vectren also segmented its analysis of all scenarios into short-, medium-, and longer-term (see pages 170-173). This appears to give Vectren more focus on maintaining a high degree of optionality which is commendable. Vectren initially prepared ten additional alternative scenarios that considered input from its stakeholders (ultimately, the number of alternative scenarios were reduced to 6 optimized scenarios). The reduction in the number of scenarios is common. The differences in the scenarios were not sufficient to cause significant changes in the resulting portfolios and didn't provide additional insights that were valuable to Vectren's decision-making processes.

4.2.1 Models, Drivers, and Scenarios

ITRON developed the long-term, bottom-up energy and demand forecasts (see page 170). As discussed in the Fuel and Commodity Price Analysis and on page 74 of the IRP, Vectren developed a consensus base case projection that was informed by several independent firms for development of its analysis. Pace Global also provided future perspectives on the Midcontinent ISO's on- and off-peak prices. Burns and McDonnell and Pace Global provided cost projections for a variety of different resource technologies that, along with other resources, were modeled for economic dispatch using AURORAxmp. Dr. Richard Stevie developed cost forecasts for DSM. Strategist was used as the primary long-term resource planning model. Vectren's objective was to minimize the Net Present Value of all of the scenarios to find the optimum scenario.

Vectren relied on traditional drivers such as the load forecast, appliance/end-use saturation, energy efficiency, weather, economic factors, etc. As stated previously, projections about the cost of natural gas and coal were the primary drivers of this IRP. MISO market prices were also a factor. Known environmental costs and potential environmental costs were a significant driver as well, but it is important to be mindful that the Clean Power Plan had relatively minor effects on the final portfolios.[16] Historically, load growth was the primary driver for long-term planning for Vectren and most – if not all – utilities in the nation. For Vectren, changes in load such as the loss of ALCOA and the development of customer-owned generation by another large customer was a major consideration in this IRP. It is possible that Vectren will see some economic growth but because this is too speculative; the potential for load growth was treated as a scenario with a hypothetical load. Energy efficiency and the potential for other customers to install their own generating resources are also important considerations in this IRP.

Against this backdrop of significant uncertainty regarding environmental rules and dramatic changes in inter-fuel relationships, Vectren's 2016-2017 IRP represents a significant expansion of the number of scenarios and sensitivities from the 2014 IRP and provides a broader range of uncertainties and their attendant risks. Vectren's objective was "to test a relevant range for each of the key market drivers on how various technologies are selected under boundary conditions." (Vectren 2016 IRP, page 182).

For the 2016 IRP, Vectren developed fourteen portfolios (pages 82 and 83). Seven portfolios (including the Base Case) were optimized, but Vectren concluded the remaining scenarios would not provide sufficient insights to warrant optimization. Below are the 15 portfolios that were tested (Business as Usual, seven optimized portfolios, two stakeholder portfolios, and five diversified portfolios). Vectren hired Burns and McDonnell to find the best possible combinations of resource additions under various scenarios by using the optimization software Strategist. The risk analysis for various portfolios was conducted by Pace Global

[16] Arguably, the accumulation of the costs for environmental rules such as ELG, CCR, MATs, etc, taken as a whole, would have been a more significant driver. However, many of these costs were already *sunk costs* at the time the IRP modeling was done.

using EPIS' AURORAxmp dispatch model combined with Monte Carlo simulation for the selection of possible future states as inputs to AURORAxmp.

1. Business As Usual (Continue Coal) Portfolio (Optimized)
2. Base Scenario (aka Gas Heavy) Portfolio (Optimized)
3. Base + Large Load Scenario Portfolio (Optimized)
4. High Regulatory Scenario Portfolio (Optimized)
5. Low Regulatory Scenario Portfolio (Optimized)
6. High Economy Scenario Portfolio (Optimized)
7. Low Economy Scenario Portfolio (Optimized)
8. High Technology Scenario Portfolio
9. Stakeholder Portfolio
10. Stakeholder Portfolio (Cease Coal 2024)
11. FBC3, Fired Gas, & Renewables Portfolio
12. FBC3, Fired Gas, Early Solar, & EE Portfolio
13. FBC3, Unfired Gas .05, Early Solar, EE, & Renewables Portfolio
14. Unfired Gas Heavy with 50 MW Solar in 2019 Portfolio
15. Gas Portfolio with Renewables Portfolio

4.2.2 Issues / Questions

Warrick 4 was assumed to be retired in all of the scenarios due to the loss of ALCOA. This raised the question of whether there are any set of circumstances – including MISO market value - in which Warrick 4 would be retained.

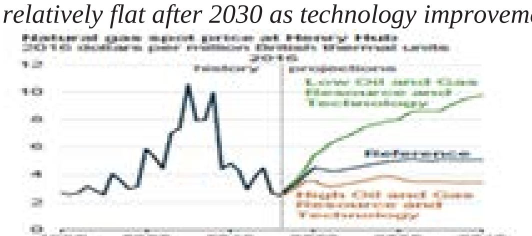
It bears reiterating from the fuel and commodity price discussion that the range of fuel price projections may have been unduly limited by using only one standard deviation from the expected value (mean). The relatively recent (5 years or so) experience in the natural gas industry provides support for a wider range of price trajectories. That is, few analysts ten years ago – even five years ago – would have thought the current price projections for natural gas to be within the realm of reasonable probabilities. Ten years ago, the notion of a *black swan event* might have been ascribed to the current projections for natural gas prices [17] and the attendant ramifications for coal in regional economic dispatch. Given Vecten's appropriate emphasis on maintaining options, having a more robust analysis of natural gas and commodity prices – higher and lower – would seem to be appropriate, especially for the mid and longer-term analysis.

Apart from whether the scenarios provided Vectren and its stakeholders with the most important information to make significant resource decisions, a more fundamental concern is capability of the model to handle the broad array of resource options in a holistic manner. That is, the capacity expansion model had limited ability to simultaneously evaluate and optimize more than a handful of resources. We recognize excessive run times may always be a consideration but the concern goes beyond run time. For example, was the model capable of simultaneously considering DSM, dynamic market conditions for buying and selling opportunities, renewable energy resources, possible new generating resources, and changes to the existing generating resource mix? Would other capacity expansion models be less limiting in their capabilities to conduct several multiple optimizations to better assess all resources and incorporate risk analysis?

Modeling results were evaluated via multiple metrics using a scorecard. The purpose was to find an appropriate balance of all metrics across the several scenarios so the choice of a portfolio performs well across the different metrics. On pages 33 and 44, Vectren identified a Preferred Portfolio Plan that, Vectren contends, balances the energy mix for its generation portfolio with the addition of a new combined cycle gas turbine facility (2024), solar power plants (2018 and 2019), and energy efficiency, while significantly reducing reliance on coal-fired electric generation and results in a significant reduction of CO_2 using Mass Compliance limits. In addition to retiring Warrick 4 in 2020, Vectren's Preferred Portfolio also contemplates the potential retirement of Bags natural gas unit 1 (in 2018) and unit 2 (2025), Northeast Units 1 and 2 (natural gas) in 2019, Brown coal-fired units 1 and 2 (2024), FB Culley Unit 2 (2024), and upgrade Culley 3 for compliance with National Effluent Limitation Guidelines (ELG) and Coal Combustion Residuals (CCR). Vectren noted the ELG/CCR, which they characterized as the main drivers of closing Vectren coal plants, will be much more difficult to change than the CPP.

While the narratives for the scenarios were well done, the Director is confident that Vectren would agree that there are reasonable scenarios that could result in different portfolios and provide a more robust assessment of potential risks. On p. 81 of the IRP report, Vectren mentioned that the seven optimized portfolios created using Strategist "looked very similar with a heavy reliance on gas resources and varying levels of energy efficiency. Some included renewables in the late 2020s through the 2030s." Therefore,

[17] The EIA's Short-Term Energy Outlook (May 8) 2007 stated *The Henry Hub natural gas spot price is expected to average $7.84 per thousand cubic feet (mcf or $7.56 per MMBtu) in 2007, a 90-cent increase from the 2006 average, and $8.16 per mcf ($7.87 per MMBtu) in 2008.* Natural gas reached an all-time high of $15.39 per MMBtu ($15.96 / Mcf) during December of 2005. On June 22, 2017, the Henry Hub Natural Gas spot price was 2. 88 per Mcf ($2.77 MMBtu). In EIA's Annual Energy Outlook for 2017 (page 56), said: *Reference case prices rise modestly from 2020 through 2030 as electric power consumption increases; however, natural gas prices stay relatively flat after 2030 as technology improvements keep pace with rising demand.*



Vectren continued with self-identified stakeholder portfolios (non-optimized) and the so-called diversified portfolios because “Vectren believes there is value in a balanced portfolio as a way to reduce risk.” The modeling results gave credence to the preferred portfolio being one of the diversified portfolios that was analyzed based on the scorecard evaluation. For Vectren, like all utilities, future IRPs need to critically examine the value of resource diversity and to do so in the context of the MISO and state requirements for reliability and economic benefits.

Two of the optimized portfolios, one from Scenario D: High Regulatory Scenario and the other one from Scenario F: High Economy Scenario, were derived from scenarios with relatively high natural gas prices (please refer to Figure 2.3 on p.78). If the model still chose to invest heavily in gas, it means investment in gas makes economic sense even with much higher gas prices. Wouldn’t a better way to test the risk be to raise the gas price to more extreme levels and see what the model selects based on the least cost criterion, rather than subjectively identifying some so-called diversified portfolios to test? More broadly, and while recognizing the number of resource options are more limited for Vectren, the usefulness of the scenario analysis may have been lessened due to the narrowness of the ranges for the important drivers that resulted in portfolios that were not often very distinct from other portfolios.

In addition, according to evaluation results shown in the scorecard on p. 85, Portfolio F actually performed well in terms of creating the right balance between satisfying the competing objectives. While the approach for ranking the portfolios according to several different criteria is good, the distinctions between rankings (red/yellow/green) seemed arbitrary. The arbitrariness of these rankings was subsequently confirmed in a data request by the CAC et al.[18] The arbitrariness, combined with the significant effects on overall rankings, raises concern. For example, the preferred portfolio ranks ninth in terms of NPVRR but gets the same green light as the lowest cost portfolio. While the use of only 3 possible rankings may be visually appealing, it exacerbates the importance of arbitrary distinctions.

Has Vectren done any retrospective analysis to see if their DSM analysis may have been limited by the same inability to optimize DSM and other resources simultaneously? As intimated by comments on Page 80 of the IRP that the iterative nature of Strategist resulted in considering only options that seemed to be viable. More broadly, has Vectren done any analysis to determine if modeling limitations resulted in a more restricted list of resources?

Despite some concerns, Vectren prepared credible and well-reasoned scenarios. As with other Indiana utilities, the degree of analytical rigor needs to be continually enhanced as the decisions become more controversial and difficult.

4.3 Energy Efficiency

Vectren used the same methodology in its 2014 IRP to analyze and model energy efficiency, which is one reasonable approach and is consistent with current practices by some utilities to address this difficult topic. Specifically, Vectren’s effort to model DSM resources in a manner reasonably comparable to supply-side

[18] CAC et al.’s Data Request 1.20 asked: Please provide the spreadsheet used to develop Figure 2.6 including the metrics measured for each of the objectives and the ranges used to determine whether a particular portfolio has a green bubble, red bubble, partially green and partially yellow bubble, etc. Vectren responded initially: Please see the Risk Analysis section (page 41-70) of the final stakeholder deck presented on November 29, 2016 (included in attachment 3.1 Stakeholder Materials) for details on how the IRP Portfolio Balanced Scorecard was developed. See the legends in the slides for each of the variables where the specifics were provided. In some instances, we used “break points” as the basis for colors.

resources is similar to the approach taken by other Indiana utilities filing their IRPs in 2016. Vectren starts off with a DSM Market Potential Study (MPS) to assess how much DSM (energy efficiency and demand response) is potentially achievable in its system. The methodology combines a dedicated MPS carried out by the EnerNOC Consulting Corporation in 2013 with a 2014 Electric Power Research Institute (EPRI) study "U.S. Energy Efficiency Potential Through 2035." The sole purpose of the Market Potential Study (MPS) was to construct an annual 2% incremental energy efficiency cap. However the construction of DSM bundles to be offered to the capacity expansion model differs substantially with the other utilities in that it didn't rely on the MPS. Instead of constructing DSM bundles by assembling measures with similar load shapes, end uses, and customer classes, Vectren set an annual cap of 2% of total eligible retail sales from the MPS. It then chose generic DSM savings in 8 blocks of 0.25% of eligible retail sales (not including large customers that have opted out) for each year of the 20 year planning horizon.

The two Market Potential Studies used by Vectren in the IRP estimated the level of Technical Potential, Economic Potential, and Achievable Potential. Technical Potential is the maximum energy efficiency available, assuming that cost and market adoption of technologies are not a barrier. Economic Potential is the amount of energy efficiency that is cost effective, meaning the economic benefit outweighs the cost. Achievable Potential is the amount of energy efficiency that is cost effective and can be achieved given customer preferences. The Market Potential studies were used solely to guide the level of DSM resources to be included in the IRP analytical process as well as the maximum levels that seem reasonable.

The component programs for the blocks are assumed to initially be those approved in Cause No. 44645. For the first two years of the planning horizon (2016 and 2017), it is assumed that the current set of approved programs are being implemented. No minimum level of energy efficiency impacts have been locked in for the planning process. The 0.25% blocks already reflect a 20% adjustment for free riders. As a starting point, the cost of the energy efficiency programs approved in Cause No. 44645 is used for the 2017 DSM resource options.

Vectren developed estimates of how the cost of each energy efficiency bundle increases as the penetration of energy efficiency increases. The estimates are based on a study done by Dr. Richard Stevie with Integral Analytics, Inc. The study found that program costs per kWh increase as the cumulative penetration of energy efficiency increases. This means that achieving 1% savings in a given year means that achieving an additional 1% the next year and every year thereafter causes the costs of EE bundles to achieve that incremental 1% to increase by 4.12% each year of the planning period. The starting cost for the second 1% of blocks is assumed to be the ending cost (in real dollars) for the first 1%. A different growth rate in cost is applied to the second set of four blocks. The second set of four blocks is expected to grow at a rate of 1.72%. The lower growth rate in cost applied to blocks 5-8 allows for economies of operation within a given year, while the higher growth rate applied to blocks 1-4 tries to capture the impact on cost over time.

Based on Dr. Stevie's modeling results, high and low energy efficiency cost trajectories were developed using the estimated standard errors of the model coefficients used to develop the Base energy efficiency cost projection. The high and low cost trajectories were created by applying plus and minus one standard deviation to the model coefficients (which would capture about 68% of the variation of outcomes around the "expected value" – or the "mean").

4.3.1 Issues / Questions

Vectren should be recognized overall for its improved analysis and interesting approaches to address a number of difficult issues that arise when evaluating energy efficiency programs. But these interesting approaches also raise a number of questions. Vectren assumed the decision to select any amount of energy efficiency is made in 2018; meaning once a bundle is selected in 2018 that bundle is kept in place every following year through the planning horizon. The implication is that a new set of energy efficiency program participants had to be recruited each year at a cost that increased 4% per year. It is unclear whether the model optimization only considered the cost of the initial year the DSM bundle was selected or if it somehow considered the cost over all the remaining years in the 20 year planning horizon as well. As noted by CAC et al. on page 36 of their comments, it is not clear "whether connecting the initial years' savings to later years would serve to bias the model against selection of energy efficiency that is not realistic." In response, Vectren performed additional analysis which looked at the competitiveness of energy efficiency over a 3-year block from 2018-2020 rather than selecting the block for the entire study period. The results showed that blocks 1-4 in 2018-2020 are relatively similar in cost as a plan with no blocks of energy efficiency under the base scenario. It is not clear to the Director whether the additional analysis performed by Vectren really answers the issue expressed by CAC et al.

Vectren should be commended for making an interesting effort to project how bundle costs changed over time and as program penetration increased. As a starting point, the cost of energy efficiency programs approved in Cause No. 44645 was used for the DSM resource options. Vectren also contracted with Dr. Richard Stevie, VP of Forecasting with Integral Analytics Inc., to evaluate how the cost to achieve incremental energy efficiency savings changes as the cumulative market penetration of energy efficiency increases. Market penetration represents the cumulative achievement of energy efficiency savings as a percent of retail energy sales. The concept is that as market penetration increases and the available Market Potential begins to deplete, the cost to achieve additional program participants may increase.

The analysis was based on the Energy Information Administration's (EIA) Form 861 which contains data by utility on DSM program spending and load impacts. There are a number of limitations when using this data, which Dr. Stevie recognizes and tries to minimize by using the most recent 3 years of data, 2010 to 2012. Another way to minimize data limitations was to look at total annual spending relative to the first year impacts.

The Director appreciates the analysis performed by Dr. Stevie but is concerned that if the adjustments made to correct for admitted serious data limitations is sufficient to overcome the problems being addressed. Drawing strong policy recommendations in such circumstances is probably not warranted. More on this topic is discussed below in CAC et al.'s comments on energy efficiency. Hopefully, future analysis will be more reliant on empirical data derived from DSM effects by Vectren's customers.

4.4. Metrics for Preferred Plan Development

Vectren states the main objective of its IRP is to select a Preferred Portfolio of resources to best meet customers' needs for reliable, reasonably priced, environmentally acceptable power over a wide range of future market and regulatory conditions, taking into account risk and uncertainty. Specifically, Vectren's objectives are:

- Maintain reliability
- Minimize rate/cost to customers
- Mitigate risk to Vectren customers and shareholders
- Provide environmentally acceptable power leading to a lower carbon future

- Include a balanced mix of energy resources
- Minimize negative economic impact to the communities Vectren serves

Vectren analyzed 15 portfolios using a number of metrics each of which were given a green color for the best performers, a red color for a worst performer, and a yellow or caution color for something between. A scorecard was used to show the color for each portfolio under seven metrics. The seven metrics were:

- Portfolio NPVRR
- Risk
- Cost Risk Trade-off
- Balance/Flexibility
- Environmental
- Local Economic Impact
- Overall

Most of these metrics consisted of multiple measures.

A. *Portfolio NPVRR* looked at which portfolio had the lowest mean or average costs across 200 modeling iterations. Portfolios within 5% of the lowest expected cost portfolio were given a green color, and portfolios that were 10% or more expensive than the lowest were given a red color.

B. The *Risk Metric* included four different measures, each designed to capture a different risk. One measure of risk was volatility which is the standard deviation of the mean NPVRR. Portfolios whose standard deviation was within 10% of the least volatile portfolio were given a green color. Portfolios that had standard deviations 15% or more than the lowest volatile portfolio were given a red.

The second measure of risk is exposure to volatilities in the wholesale energy market prices. The portfolio with the lowest average purchases from the market is subject to the least market price volatility. Those with less than 800 GWhs per year on average were given a green color and those above 1,200 GWhs were given a red color.

The third measure assessed is the exposure to MISO capacity market prices. The average number of additional capacity purchases across all 200 iterations was computed to see which needed the most incremental capacity purchases. Portfolios purchasing less than 20 MW per year on average received a green color and those above 35 MW received a red color.

The fourth risk measure is remote generation. Portfolios with generation assets located away from Vectren's service territory are thought to be exposed to greater risk of transmission congestion and outages.

C. *Cost-Risk Tradeoff* relates two variables: expected costs and the standard deviation of cost. It is meant to provide a metric of whether a portfolio hedges risk in a cost effective manner. Vectren presented a figure (p. 229) that measured portfolio standard deviation along the vertical axis and expected portfolio cost along the horizontal axis.

D. All of the portfolios would easily meet or exceed the requirements of the CPP. Also, nearly all of the portfolios will reduce SO_2 and NOx levels by over 80%.

E. According to Vectren, balance and flexibility are important objectives to "ensure that Vectren has a diverse generation mix that does not rely too heavily on the economics and viability of one technology or one site." (p. 229). Portfolios with the greatest number of technologies are ranked higher than those with fewer technologies. Also, portfolios with more net sales into the wholesale market have the flexibility to adapt to unexpected breakthroughs in technology.

Sub-measures for Balance and Flexibility include the following:

- Percentage of the portfolio consisting of the largest technology in MW (for example wind or gas-fired generation)
- The largest power source (for example a combined cycle unit or a coal-fired unit)
- Percentage reliance of the largest technology to meet energy requirements in 2036 (for example gas or wind)
- Balanced energy metric based on the number of technologies relied on (for example gas, wind, solar EE, coal)
- Market flexibility as measured by net sales into the wholesale market.
- There was also a summary metric based on the other six sub-measures in this category

F. The last metric is local economic impact to the community. According to the IRP, this includes local output reductions and tax losses if local generation facilities are closed. Construction additions and operation of replacement generation was considered.

The customer rates metric, which is actually based on the portfolio's NPVRR, is useful, but is, by itself, limited. Knowing the mean or average NPVRR for one portfolio compared to other portfolios is of limited value without having information on the variability within the metric. Fortunately, Vectren presents information related to costs risks under other performance metrics. The risk metric included, as one element, the standard deviation of 20 year cost NPVRR. Another metric evaluated the cost-risk tradeoff by relating the expected value (or mean) of the 20 year NPVRR for a portfolio to the portfolio's standard deviation.

4.4.1 Risk Metric

Vectren presented three different measures relating to the NPVRR but each was discussed separately with no reference to the other two measures. It is often the case that a portfolio with a higher average NPVRR and a lower variability will be preferable to a resource portfolio with a lower average NPVRR but higher variability. Based on the information presented by Vectren, it is difficult to determine how the portfolios compare. It looks like Portfolio D has the best Cost Risk tradeoff but how the other portfolios compare is difficult to determine, given the information presented. The Director wonders if the cost-risk tradeoff could have been better presented using some other measure such as a cumulative probability chart. The risk probability chart would have shown the distribution of PVRR outcomes from the stochastic draws, showing the outcomes as the cumulative probability of each occurrence between 0% and 100%. The figure contains the risk profiles for each portfolio, with PVRR along the X-axis and the cumulative probability on the Y-axis. For each line, the difference between the bottom left point and top right point on the line is the range which 100% of the outcomes are expected to fall. This type of figure was used by IPL and has been used by other Indiana utilities including IMPA and I&M.

As noted above, the risk metric consists of four separate measures and each receives equal weight. Two of the measures relate to exposure to different aspects of the MISO markets. One measures exposure to the MISO wholesale energy market and the other measures exposure to the MISO capacity market. A third measure considered the risk from transmission issues from remote sources to Vectren which primarily affected those resource portfolios with greater reliance on wind generation.

An obvious question is how the thresholds were developed for exposure to the MISO capacity and energy markets? There is no discussion of thresholds in the IRP itself or the slides for the November 29, 2016 stakeholder meeting that addressed the performance metrics. Especially without a narrative that has been informed by discussions with MISO, it is hard to avoid the conclusion that the thresholds for good levels and bad levels of exposure is arbitrary. Without knowing why the thresholds were set where they are it is difficult to understand the significance when one portfolio receives a green light while another receives a red light. As for the third measure dealing with remoteness of resources to Vectren, there does not appear to be a definition of remoteness. Is it merely any resource that is not directly interconnected to the Vectren transmission system? Are there different degrees of "remoteness"? If yes, on what are these degrees based? If remoteness is based only on whether a resource is directly connected to Vectren's transmission system, then this is a blunt measure. Again, it would seem that MISO would be a good resource to help Vectren quantify the metrics.

4.4.2 Flexibility Metric

The balance and flexibility metric discussion in the IRP differs quite a bit from that in the November 29, 2016 stakeholder meeting presentation. For example, the IRP (p. 230) states that portfolios with more net sales have the flexibility to adapt to unexpected breakthroughs in technology. The November 29 stakeholder presentation says portfolios with higher net sales provide a cushion against higher than expected load, as well as redundancy to quickly adapt to unexpected change. The idea is to reduce the likelihood of exposing customers to wholesale energy market volatilities (p. 72). It is not clear to the Director why higher net sales is protection against unexpected change - be it technological change or something else. For example, higher net sales could also indicate greater sunk costs associated with generation facilities.

4.4.3 Diversity Metric

To some extent, flexibility concerns are addressed by Vectren's diversity metric, which uses four measures. These measures cover both the percentage of energy and capacity requirements satisfied by one technology, the largest single generation source, and the total number of technologies utilized. It is important to note that these measures are based on the projected load and resources for 2036. Again, it is not clear how the thresholds were set for green, yellow, or red classification for the specific measures. Nor is it clear how the summary metric was developed based on the four diversity measures and the net sales measure.

CAC et al. (on pages 47-57) has a number of criticisms of the black box scorecard assessment used by Vectren. Its exercise demonstrates how small changes to the scorecard ranking system implemented by Vectren can result in very different rankings of portfolios. As CAC et al. noted, the scorecard methodology used by Vectren is not robust to small changes in metric assumptions nor is it the only possible interpretation of the data on which Vectren relies. (CAC et. al. comments on Vectren IRP, p. 51) The Director concurs with this criticism.

4.4.4 Assessment

Vectren's circumstance is quite similar to NIPSCO's, in that both utilities are considering the reasonableness of making significant changes to its resource portfolio in the next several years. Similar to NIPSCO, Vectren relied extensively on PVRR to compare resource portfolios in its 2014 IRP, but has made a significant number of improvements in the 2016 IRP. There is an extensive discussion of risks and uncertainties and an explicit effort to have metrics that specifically address these risks and uncertainties to evaluate portfolio performance. Vectren included metrics to measure balance and flexibility of portfolios, local economic impact, cost-risk tradeoff, and environmental compliance. The specific questions and issues discussed above are not meant to detract from the significant improvements in the use of metrics implemented by Vectren in the 2016 IRP. Rather, the questions and issues are intended to further discussion amongst the various stakeholders and Vectren to make ongoing improvements.

5. HOOSIER ENERGY

5.1 Scenario and Risk Analysis

Hoosier Energy filed an update, rather than a full IRP, as part of the change to a three-year IRP cycle. Its update was well-organized and credible.

5.1.1 Models

Hoosier Energy contracted with GDS Associates to perform IRP analysis by using the Strategist Integrated Planning System developed by *Ventyx*. The model simulates production operations of all combinations of potential resource additions, then compares across those combinations to determine the portfolio of expansion units necessary to achieve planning reserve margin criteria at the lowest cost. The model is the same as the one used in 2014 IRP process.

5.1.2 Method

Hoosier Energy started with a Base Case scenario. Eight sensitivities were developed for the Base Case by incorporating different assumptions about load and energy, fuel prices, renewable prices, carbon prices and overnight costs for Combined Cycle and Combustion Turbine construction. In addition to the Base Case scenario, an Environmental Future scenario was developed, which included carbon emissions limits and a limited amount of wind over the 2017 to 2036 timeframe. Seven sensitivities were developed for the Environmental Future Scenario with varying limits on wind and solar and those limits combined with low power and gas prices.

Hoosier Energy reported the least cost plans under each scenario and sensitivity. Nevertheless, it did not reach a preferred resource plan after the analysis. A short-term action plan indicated that the next major resource increment would be required around the years 2023/2024 based on modeling results.

5.1.3 Issues

In Hoosier Energy's IRP analysis, only supply-side alternatives were included in the modeling. The demand-side resource options were predetermined and incorporated into the load forecast. The supply-side and the demand-side alternatives were not evaluated on the same basis in the resource plan process.

Hoosier Energy included a very limited number of scenarios: Base Case scenario and Environmental Future scenario. Usually, a scenario represents a possible future depicted by a set of input assumptions about economy, market condition, load and energy forecast, environmental regulation, and so on. From the perspective of identifying possible future states, two scenarios seem insufficient.

In addition, Hoosier Energy lacked a systematic framework to compare various portfolios. Except cost, no other criteria were established to make comparison. Modeling results were presented in a way less informative, which did not lead to a preferred portfolio plan.

5.2 Energy Efficiency

Hoosier Energy's circumstance is quite different from that of the other three utilities that submitted IRPs this round. NIPSCO, IPL, and Vectren all prepared completely new IRPs consistent with the schedule in the draft IRP rule. Hoosier Energy was scheduled to provide only an update of the IRP with a completely new IRP to be prepared for 2017. This is part of the transition to a three-year cycle for each utility to prepare an IRP going forward.

Hoosier Energy's discussion of demand-side resources is minimal but it appears DSM was reflected in the IRP a couple of different ways. First, DSM resource options were selected and developed as part of the 2013 GDS Associates market potential study and incorporated into the load forecast. Second, GDS developed a 2016 update of its study. Based on the updated assumptions, an additional 3.5 MW of DSM was selected in 2017 in some of the Strategist scenarios. How either step was done is not discussed.

The Director understands that Hoosier Energy was only providing an update to its IRP as requested under the draft rule. He anticipates that Hoosier Energy will have a fuller discussion of how DSM resources are accounted for in their 2017 IRP.

5.3 Metrics for Preferred Plan Development

Hoosier Energy developed two scenarios that were analyzed with Strategist – a Base Case and an Environmental Future. Eight sensitivities were analyzed for the base case and seven sensitivities for the environmental future scenario. Tables for each scenario and sensitivity showed the five lowest cost expansion plans (from the top 100) selected by the Strategist model. The NPVRR of each resource portfolio was the only information presented. No other metrics for plan evaluation was discussed.

Staff understands that Hoosier Energy was only providing an update to their IRP as requested under the draft rule. We anticipate that Hoosier Energy will have a fuller discussion of performance metrics in its 2017 IRP to inform its decision as to the composition of the preferred resource plan.

6. CAC ET AL. COMMENTS

CAC et al. raised a number of concerns as to how the utilities modeled DSM. Attention was especially focused on the use of market potential studies, bundle creation, and the projection of energy efficiency costs over a 20-year forecast horizon. CAC et al. also proposed an alternative DSM modeling methodology that they think avoids many of the difficulties they see with the methodologies used by the utilities.

CAC et al. commented that much of the analysis reflected in the market potential studies is opaque with assumptions that are unspecified or less than clear. (CAC et al. Comments on IPL IRP, pp. 39 – 42) They are also concerned how the market potential studies were used to screen potential EE programs multiple times. (CAC et al. Comments on NIPSCO IRP, pp. 28-30) Essentially, CAC et al. have a number of questions regarding the movement from the MPS to what is included for consideration in the optimization model and how the energy efficiency in the Preferred Plan relates to what occurred throughout the process.

CAC et al. thought Vectren's treatment of DSM was in many respects superior to that done by IPL and NIPSCO. Much of this is the direct result of how Vectren created its DSM bundles compared to the methodology used by IPL and NIPSCO. In CAC et al's. opinion, they thought Vectren's approach had beneficial attributes because it "does not rely on such black box elements as 'achievable potential' rates. In addition it does not appear that Vectren performed any cost-effectiveness pre-screening of measures, which generally serves only to result in more screens for the energy efficiency than supply-side measures." (CAC et al. Comments on Vectren IRP, p. 35)

Perhaps CAC et al. reserved their largest concern for how efficiency program costs were projected to change over the 20-year planning period. As noted above, both IPL and NIPSCO assume initial bundle costs similar to existing DSM programs or base information on market potential studies, and each company made assumptions as to the rate of annual escalation in bundle costs. It is not clear on what these annual cost increase projections are based. Vectren's approach based initial bundle costs on programs they are currently marketing, but the rate of cost increase is based on a study done by Dr. Richard Stevie.

CAC et al consultants prepared a paper critiquing the analysis done by Dr. Stevie. (CAC et al. Comments on Vectren IRP, Attachment A) They found that Stevie's analysis:

- is based on highly questionable data sources,
- relies on regression analysis that is sensitive to the inclusion or exclusion of problematic data entries, and seems to depend on unusual choices in variable and model specification, and
- is applied incorrectly and incompletely in the utility filing where the consultants were able to review confidential workpapers.

CAC et al. concludes the "result is higher energy efficiency costs than would otherwise be expected in utility planning and, consequently, less efficiency chosen in optimal resource planning." (CAC et al. Comments on Vectren IRP, Attachment A, p. 3)

To Vectren's credit, they recognize that DSM resource costs are a component of the integration of DSM into the resource plan. The uncertainty around DSM costs, especially considering a 20-year implementation period, means that alternate views of these costs should be examined in the context of the scenario and stochastic risk analyses. (Vectren IRP p. 134)

Vectren developed high and low DSM resource cost trajectories using the estimated standard errors of the model coefficients used in the development of the base case cost projection. These high and low load cost trajectories were created by applying plus and minus one standard deviation error to the DSM costs regression model coefficients. (Vectren IRP p. 135)

The use of high, low, and base DSM costs forecasts is very useful conceptually, but the Director shares CAC et al's. concern about the methodology and data used to develop the base case DSM costs trajectories based on EIA data. For example, the costs for an individual DSM block 1- 4 increases by 4.9% per year in the high case, 4.2% in the base case, and 3.4% in the low case. Given low inflation rates all three rates of DSM costs increase translates into substantial increases in the real (meaning inflation-adjusted) costs of DSM. This appears to be inconsistent with other historical evidence. Also, while using high and low DSM cost trajectories is methodologically reasonable to evaluate how sensitive modeling results are to changes in DSM costs, the apparent high increases in real costs over time across all three projections raises questions about how the method was applied and the reasonableness of the results. More fundamentally, the methodology used by Vectren appears to underestimate the role of technological change and changing public attitudes about energy consumption. It is not clear to the Director that this can be adequately captured when using only three years of data. The ideal solution would be to develop a Vectren specific load research – including DSM load research – database, but this takes time. Borrowing data from neighboring utilities and selected utilities that have substantial experience and expertise is a second-best alternative. However, as Vectren knows, borrowing data from other utilities must be carefully done since there are considerable differences in how utilities treat DSM. The lack of uniformity in treatment and reporting of DSM to the EIA is a primary reason that reliance on EIA DSM data is concerning.

CAC et al. recommends moving away from the current approach of using bundles to evaluate the potential for EE in IRP modeling and instead trying to focus on the value of EE. This, they suggest, can be done by moving to an avoided cost proxy for DSM. A utility will use IRP modeling to estimate the value of increasing zero cost decrements of load so that an implicit avoided cost for each decrement is developed. Under this approach, the appropriate level of energy savings is calculated in a DSM proceeding but relies on avoided costs developed from the IRP. This approach eliminates the need at the IRP modeling stage to develop assumptions about the cost and performance of DSM over the 20-year planning horizon. CAC et al. notes the avoided cost proxy requires having portfolios with distinct levels of energy savings but similar resource choices and other input assumptions so that the cost differences between the portfolios is driven by the level of energy savings rather than some unrelated characteristic. (See p. 40 CAC et al's. Comments on IPL IRP and p. 38 of CAC's Comments on NIPSCO's IRP)

The Director shares CAC et al.'s concern about the ability to develop assumptions about DSM bundle characteristics and cost trajectories over a 20-year modeling horizon. As a result, the Director appreciates the alternative methodology proposed by CAC et al. While conceptually reasonable, the idea, however, has to be more fully developed and analyzed using appropriate models so there is better understanding of how use of the technique compares to other techniques of EE modeling being used across the nation.

7. MIDWEST ENERGY EFFICIENCY ALLIANCE (MEEA) COMMENTS

MEEA shared many of the same concerns expressed by the CAC et al. They liked each utility choosing to model EE as a selectable resource but also expressed a number of concerns about the EE modeling methodologies used by NIPSCO and IPL, which are listed below.

1. Each utility used its respective MPS to screen EE programs which MEEA believes unreasonably limits the amount of EE included as an input to the IRP optimization modeling. They prefer the "Technical Potential" be input to the IRP models. (MEEA NIPSCO comments, p. 3)
2. Each bundle was based on individual measures which could be leaving savings on the table that could be achieved with a well-designed portfolio of programs. (p. 2 MEEA NIPSCO Comments)
3. The savings levels are too low. In MEEA's experience it is not uncommon that higher levels of cost-effective energy savings can be achieved as technology, program design, and program delivery mature. (MEEA Comments on NIPSCO, p.4)

MEEA did like IPL's method of separating the bundles into cost-tiers compared to the no-tiers approach used by NIPSCO. They believe bundles based on cost tiers prevent an all-or-nothing selection in the IRP modeling. (MEEA Comments on IPL, p. 2)

MEEA especially liked Vectren's approach to bundle construction, as compared to IPL and NIPSCO. But MEEA had one caveat – the 2% cap on incremental annual energy savings appears to be arbitrary, as do the 0.25% size of the bundle increments. They questioned if the 2% level was too low. Also, they wondered if smaller increments of 0.10% had been used would more energy savings have been selected. (MEEA Comments on Vectren, p. 2) MEEA, in addition, thought Vectren's approach of allowing the model to select EE by cost per kWh in a measure-agnostic fashion avoids limiting what EE is available to the IRP model. This avoids limiting the utility's later DSM planning because it selects savings rather than specific measure types. (MEEA Vectren Comments, p. 3)

According to MEEA, NIPSCO used Version 1 of the Indiana Technical Reference Manual (TRM) in its MPS whereas IPL used Version 2.2. They asked the commission to provide guidance on which version of the TRM should be used in IRP modeling. It is the Director's opinion that the most recent version or data should be used whenever possible. (MEEA Comments on IPL, p. 3)

Utility Responses to MEEA

Both IPL and NIPSCO disagree with MEEA that their modeling is flawed because they failed to include MPS Technical Potential in the IRP optimization. IPL says they intentionally chose to input MAP in the

IRP modeling rather than the lower RAP so as not to limit the amount of DSM available for the IRP model to select. (p. 3, IPL Reply to Stakeholder Comments). NIPSCO states it made a conscious decision to screen EE measures for what was not just possible in its service territory, but also what was practical. (NIPSCO Reply Comments p. 6) In order for the EE bundles to be the most accurate representation of what is available, NIPSCO elected to use the more conservative, but more typical market by also running the EE program potential on all of its measures before including them in the optimization. (NIPSCO Reply Comments, p. 7)

As to the assertion that the savings level is too low, IPL emphasizes that, after opt-outs are considered, the IRP-selected energy efficiency amounts are more than 1% per year of the eligible load. (IPL Reply Comments p. 3) NIPSCO noted that many DSM programs passed the DSM pre-screening process but were ultimately not selected in the model optimization process. As a result, any DSM program that was unable or narrowly able to pass the screening would be highly unlikely to be chosen in the resource optimization. (pg. 2-3 NIPSCO Reply to Stakeholder Comments)

8. GENERAL COMMENTS

8.1 Fuel and Commodity Price Analysis for Director's Report on 2016 IRP

The Director recognizes any expectation of precisely accurate forecasts of future fuel and market prices, especially long-term price forecasts, is an impossible objective to attain. Rather, the emphasis should be placed on the plausibility and credibility of different narratives and assumptions that, considered with other factors, provide a broad range of possible outcomes. Given the significance of decisions being confronted by Indiana utilities and their stakeholders, it is important to memorialize the importance of fuel prices—particularly natural gas prices—in relation to coal prices. Similarly, it is important to note that environmental policies affecting coal are changing at the national level but, at this point, it is difficult to anticipate the ramifications. These changes were made after utilities conducted their analysis and generally occurred after the IRPs were submitted. The importance of fuel prices is preeminent in this IRP cycle and warrant well-constructed scenarios, sensitivities, probabilistic analysis, and multiple data sources. Moreover, since Indiana utilities are members of the Midcontinent ISO (MISO) or the PJM, it is also necessary for Indiana utilities to consider market prices and regional resources to maximize the value of their own resources over the 20-year planning horizon.

8.1.1 Construction of Fuel Forecasts

Developing low probability, but highly consequential scenarios, as well as more likely scenarios, is consistent with good industry practice.[19] Similarly, for fuel price projections, forecasts of market energy and capacity costs, load forecasts, environmental regulations and other important variables, especially those that are likely to be primary drivers of resource decisions, should capture a wide variety of assumptions and projections. Analysis of more extreme fuel price assumptions and forecasts should result in different resource portfolios that provide useful insights that could not be provided by too narrow a view.

Just as well-reasoned narratives are essential in the construction of scenarios, it is also imperative that well-reasoned narratives support fuel price projections. Even extreme fuel price forecasts should be supported

[19] The Northwest Power and Conservation Council "Northwest Conservation and Electric Power Plan". The Council's planning process is based on the principle that "there are no facts about the future." The Council tests thousands of resource strategies across 800 different futures to identify the elements of these strategies that are the most successful (i.e., have lower cost and economic risk) over the widest range of future conditions. (page 3-30). The Regional Portfolio Model (RPM) [A stochastic not deterministic model] uses both natural gas and wholesale electricity prices as the basis for creating 800 futures. Each future has a unique series of natural gas and electricity prices through the 20-year planning period. [For natural gas prices] These price series include excursions below and above the price ranges shown here for both electricity and natural gas to reflect the volatility and uncertainty in future commodity prices. (page 8-2). The high and low forecasts are intended to be extreme views of possible future prices from today's context… In reality, prices may at various times in the future resemble any of the forecast range. Such cycles in natural gas prices, as well as shorter-term volatility, are captured in the Council's Regional Portfolio Model.(page 8-8). The future is uncertain. Therefore, the ultimate cost and risk of resource development decisions made today are impacted by factors that are largely out of the control of decision makers. To assess the potential cost and risk of different resource strategies, it is essential to identify those future uncertainties that have the potential to significantly affect a resource strategy's cost or risk, and to bracket the range of those uncertainties. (page 15-4). Seventh Power Plan, Adopted February 10, 2016.

by a credible narrative story. For example, what can history—especially recent history—tell us?[20] What combination of factors might cause significant natural gas price escalations (or significant price declines)? What factors, taken together, might cause a significant increase in forecast market energy and/or capacity costs that would alter resource decisions?

To be clear, there is no expectation that the utilities' preferred resource plans will be based on very extreme cases. However, it is important to know the point of inflection when extreme scenarios result in dramatic changes in resource portfolios. For example, what price do natural gas and coal price projections have to reach for utilities to retain their coal-fired generation? Similarly, what natural gas and coal price projections would cause a utility to retire all coal-fired generation? For either of these two examples of high and low fuel and market prices, how does the capacity expansion planning model's selection of other resources change and what are the ramifications?

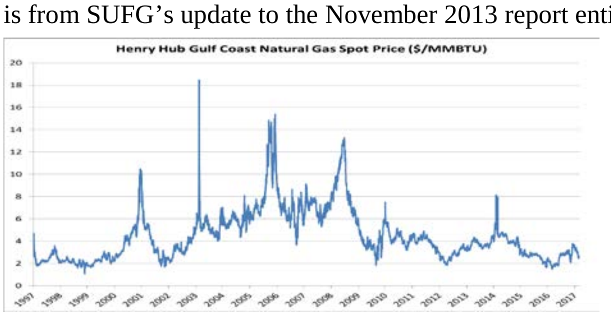
Because business decisions are likely to be increasingly formulated as a result of the IRP process, analysis, and data, and because of the importance of fuel as a driver, utilities should consider using multiple (two or more) independent fuel price forecasts. Ideally, at least one of these forecasts should be a credible forecast in the public domain such as from the Energy Information Administration (EIA). Each of the fuel price forecasts should be supported by a reasonable and credible narrative.

8.1.2 Commodity Forecast Framework

Since the MISO and PJM conduct security constrained economic dispatch to ensure the lowest cost combination of resources are dispatched at any moment in time, subject to constraints, it is essential that Indiana utilities give consideration to a variety of different energy and capacity market price scenarios and sensitivities that could affect their operational and longer-term resource decisions. As with fuel and other forecasts, long-term regional estimates should be supported by credible narratives. For example, regardless of the spread between coal and natural gas prices used in economic dispatch decisions, if a resource is not frequently "in the money" for MISO's and PJM's dispatch, this should be part of a narrative and should be a reference point for the reasonableness of portfolios.

A statewide and regional perspective could provide useful insights and it would be consistent with the IRP statute and draft rules. A statewide (ideally a regional) analysis could provide additional perspectives to

[20] With the exception of a brief spike in early 2014 that was related to an extreme cold spell (commonly referred to as the polar vortex), natural gas prices have remained low since 2013. It should be noted that the 2014 spike was less extreme than those during the winters of 2000/2001, 2003, 2006, and 2008. Horizontal drilling and hydraulic fracturing has allowed the U.S. to capture significant amounts of natural gas from shale formations, where it was previously uneconomic. The result has been a transformation of the characteristics of natural gas prices. This is illustrated by the graph on the following page (data source: Energy Information Administration (EIA)). Information is from SUFG's update to the November 2013 report entitled Natural Gas Market Study. (p. 1).



inform the Commission, policymakers, and stakeholders, and help Indiana utilities assess retirement, retention, and repowering decisions, as well as the potential for future joint projects if technology improvements result in making certain resources economically viable.

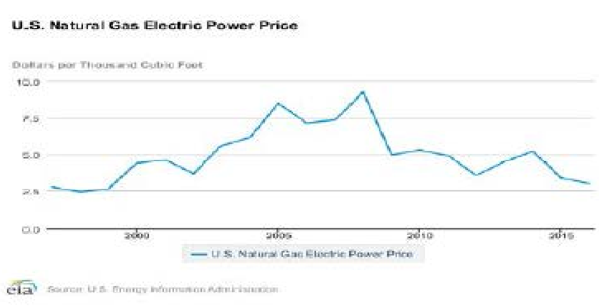
Ideally, Indiana utilities would work with their respective RTOs to consider the broader regional implications of a variety of short, mid-term, and long-run resource options that are comparatively economical and provide appropriate reliability. For example, if a significant amount of coal-fired capacity is being retired in the MISO and/or PJM regions, would this influence retirement decisions for coal units in Indiana?

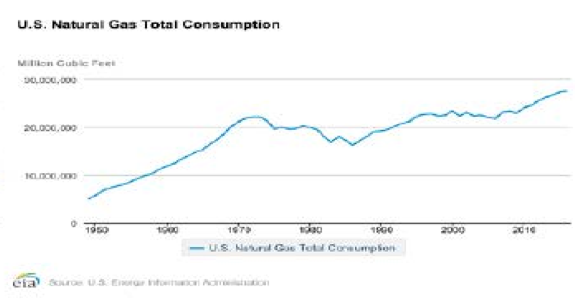
8.1.3 Discussion of Common Issues / Questions

IPL, NIPSCO, and Vectren all used reputable consultants that specialize in energy price forecasts. IPL and Vectren used more than one fuel price projection in their IRPs which seemed appropriate given the importance of fuel prices in this round of IRPs. Especially with the natural gas expertise of NIPSCO and Vectren, as combination utilities, the expectation is higher for well-reasoned narratives to explain the price projections.

To varying extents and owing to the complex interactions of fuel and wholesale electric market prices on load and resources, the narratives offered by IPL, NIPSCO, and Vectren to support their development of assumptions about fuel and wholesale electric market price projections may be too constrained. On page 170 of Vectren's IRP, for example, Vectren said: "…The current over-supply of natural gas continues to dominate the market dynamics. However, low prices eventually result in restricted production and reduced gas supply. Coupled with new LNG export terminals and new heavy industrial facilities, demand rise and gas markets begin to tighten, …Meanwhile coal prices remain depressed in the near short-term as domestic markets remain soft , with a modest price recovery beginning in in 2018." While all of the utilities made similar observations which have considerable merit and plausibility, the fuel and commodity markets seem far more nuanced than traditional supply and demand analysis would offer. For example, none of the utilities advanced an argument predicated on significant technological enhancements and the complex and, often non-intuitive, price elasticity of supply interactions among oil, natural gas, and coal. For future IRPs, foreign trade complexities should also be included in the analysis.[21] It seems that natural gas supplies, for instance, can change quite quickly to changes in the price of oil or natural gas. To the extent that the fuel

[21] According to the EIA (2016), significant improvements in drilling efficiency, well completion techniques, fracturing technologies, and multi-well drill sites (8 to 10 horizontal wells from a single well pad) have substantially increased gas supply.. From 2012 – 2016, well productivity has increased by roughly 300 percent. As a result, natural gas prices are likely to be steadier and less volatile than in the past. As oil and gas producers continue to improve well completion technologies, each well will become more productive and impactful on overall supply.





and market price projections were too constrained, it has an adverse effect on the development of scenarios and sensitives. For example, depending on assumptions for price projections, couldn't reasonable scenarios be constructed for Indiana utilities to address the following types of potentialities?

- Is it possible for natural gas and coal prices to diverge during periods over the 20-year planning horizon?
- Is it possible that reduced customer demand for electricity (perhaps a recession) may not result in lower natural gas or coal prices? Recall the recessions of the 1970s and 1980s where the price of natural gas, coal, and nuclear fuel were very high.
- Would the utilities agree that some level of increased customer demand may not always result in higher coal and/or natural gas prices? Recent history provides an example.
- Are there opportunities for the coal industry, perhaps in concert with the railroads, to lower the delivered cost of coal to a point that may slow the retirement rate of coal-fired power plants?
- Suppose the FERC and the courts reject current attempts by states to subsidize the continued operation of coal and/or nuclear generating units. Does this affect the economics of Indiana generating resources? Correspondingly, did the utilities consider the implications that might result from most utilities retaining much of their coal (and nuclear) generating fleets?
- Suppose state and/or federal law bans fracking in much of the United States. While an admittedly unlikely event, should this be considered in the development of scenarios?
- After the IRPs were submitted, substantial fracking opportunities were discovered (e.g., the Permian Basin). Recognizing the IRPs are a snap shot in time and the IRP analysis was completed before substantial new natural gas potential was public, do the utilities feel the lower natural gas prices projections used in their scenarios might have been even lower?
- Recognizing that the IRPs were developed with the expectation there would be no change in environmental policy, would it have been useful to model a diminished environmental policy?
- What, if any effect, was given to coal and natural gas industry bankruptcies? Did these influence the narratives to justify the fuel price projections?
- What would be the ramifications of lower renewable and EE prices - perhaps due to increased efficiencies beyond those currently projected - on fuel and commodity price forecasts?
- In developing utilities' scenarios and sensitivities from the narratives provided by independent experts for fuel price projections, did the companies' fuel price projections consider international trade and markets for coal and liquefied natural gas exports (imports) over the 20-year planning horizon and the effect on domestic markets?
- What happens to this scenario if trade practices become very restrictive?

Of course there are other potential scenarios. We urge the utilities to give increased consideration to plausible scenarios, including those that have significant ramifications but relatively low probabilities of occurrence. To be clear, there is no intended implication that utilities should run several additional scenarios. Rather, the intention is an expansion of the narratives for the scenarios to have considered a wider range of possible fuel and commodity price projections in the construction of scenarios.

Historically, fuel and resource diversity was also thought to provide greater reliability and serve to moderate volatile commodity prices. More diverse resource portfolios, however, are not necessarily more reliable. The historical price volatility that characterized the natural gas industry for decades may be largely a thing of the past due to fracking, but future prices could be influenced by global markets. Long-term decisions should be informed by an understanding of the dynamics and inter-related complexities of U.S. commodity markets and the influence of global markets. It is incumbent on the utilities to continually evaluate the commodity markets and assess the complex U.S. market interactions while valuing fuel and resource diversity.

8.2. Scenario and Risk Analysis

All Indiana utilities, as well as utilities throughout the nation, are confronting significant uncertainties and risks that seem certain to result in changes in their resource portfolios due, primarily, to projections of low natural gas prices compared to coal. The aging of the existing coal fleet and the very high cost of building new coal-fired generating units poses a significant economic challenge to coal as a fuel source. Even nuclear units in many regions struggle to be cost competitive in the current markets. The rapidly declining cost of renewable resources and the increased capability of the transmission system to carry these resources to distant markets is also a factor. DSM, including improved appliance and end-use efficiencies, is a resource that is likely to be increasingly utilized, even at a time when load growth is minimal or even declining.

Based on these national uncertainties and risks, the Director sees challenges to valid concerns about the rigor and credibility of load forecasting for larger customers in Indiana. Because of the importance of larger customers for NIPSCO and Vectren, in particular, the risks of over- or under-forecasting the demand and energy use of larger customers is important. Especially taken together, changes in the operations and business climate have significant ramifications for these utilities, their employees, customers, communities, and investors.

Each utility said they were taking steps to improve its forecasting for its customers – including the largest customers. These factors heighten the importance of recognizing, assessing, and bracketing the broad range of potential risks and provides opportunities for utilities to develop resilient strategies to minimize adverse consequences of risks. IPL and Vectren made excellent progress in attempting to interject greater use of probabilistic analysis into traditional scenario-based analysis with the recognition that it is a work in progress. Consistent with the IRP draft rule, these initial efforts will mature in future cycles. NIPSCO's efforts to improve its risk analysis were not as successful due to the inability of its models to integrate probabilistic analysis into its IRP. As a result, NIPSCO's IRP was almost certainly not as informative as NIPSCO would have preferred. According to NIPSCO, future IRPs, using more comprehensive state-of-the-art models and improved databases, will not suffer the same limitations.

8.3 Energy Efficiency Issues / Questions

Each of the three utilities is to be congratulated on the significant methodological improvements made so that DSM and other supply-side resource options are treated more comparably. A comparison of the methodologies across the utilities is informative but brings a number of questions to mind.

NIPSCO and IPL used a very similar approach to create DSM bundles, which is in sharp contrast to that used by Vectren. To be clear, the differences in approach should not imply that one method is more efficacious than another. IPL and NIPSCO combined measures with similar load shapes, customer classes, and end uses into bundles. Vectren chose to base bundles on generic DSM savings in eight blocks of 0.25% each year of the planning horizon. The component programs for the blocks developed by Vectren are assumed to initially be those approved in Cause No. 44645.

With regard to Vectren's methodology, every bundle is exactly the same except for costs. More importantly, the load shape of the energy efficiency bundles was exactly the same across the bundles and through time. Vectren used the Strategist default DSM load shape for each bundle which is very comparable to the DSMore load shape used in the 2013 Vectren MPS. In contrast, the bundles prepared by IPL and NIPSCO had load shapes that differed across bundles at any point in time. It is unclear if the load shapes were held constant over time but that appears to be the case. It is not obvious to the Director which approach to developing bundles is superior. Is a uniform bundle, with a uniform load shape, preferable to bundles based on end-use with associated load shapes? Is a resource optimization model going to select a different aggregate amount of DSM based on how these bundles are assembled?

Based on the information available from IPL, NIPSCO, and Vectren, it is not clear that one approach to handle limitations in optimization modeling is superior to another. Certainly, the state-of-the-art computing capability – including reduced run times and modeling sophistication to conduct simultaneous optimization rather than painstaking iterations – has advanced significantly in the last five years. It is likely that models will grow increasingly capable, thus reducing the limitation over time. Regardless of advances in modeling capabilities that are warranted to address the increasingly complex and financially consequential decisions that utilities have to confront in the next few years, the benefits of these new capabilities may not be fully realized until utilities have additional statistically-credible experience to better document the changes in how different customer's use energy and the effects on system peak demand, both within Indiana and across the country, to better inform resource decisions in the future. IPL, in particular, should be commended for its expansive deployment of Advanced Metering Infrastructure (AMI) and its willingness to explore how to more fully develop the information needed for the next generation of DSM analysis.

For Vectren, the different bundle creation processes also demonstrated an entirely different role for - or use of - the respective Market Potential Studies. Vectren's use of identical bundles with a generic load shape was not based in any way on its MPS except to provide indicative information as to the maximum amount of energy efficiency available in its service territory. In other words, Vectren used the MPS to decide if the maximum annual potential savings was 2% or something else. Thus, the MPS was used to decide how many bundles should be considered in any one year which Vectren decided was eight bundles. At this early stage of DSM analysis, the Director takes no position on the efficacy of this approach compared to alternatives except to suggest that the MPS may provide more useful information than was utilized by Vectren.

Both IPL and NIPSCO made extensive use of their respective MPS. Each company used the Market Potential Study to determine the different levels of DSM potential: technical, economic, and achievable. This information was then used by MMP to develop bundles that would be used as resource options in the IRP optimization process. Importantly, the MPS analyses was based on individual measure data and so were the bundles that were fed into the optimization model. The penetration of the measures in each bundle was based on information contained in the MPS.

For both IPL and NIPSCO, MMP utilized the DSMore economic analysis tool to perform a final screening to determine whether the measures coming out of the MPS were cost effective, taking into account utility specific rates, cost escalation rates, discount rates, and avoided costs. Vectren did not perform this step given how they developed its DSM bundles. Vectren instead used its most recent MPS to make sure that Vectren's 2016 levelized DSM cost (the starting point for this analysis) was reasonable.

For all the similarity in overall methodology used by NIPSCO and IPL, there are a couple of differences to note.

1. Both NIPSCO and IPL used the Achievable Potential as determined in their respective MPS. IPL divided the Achievable Potential into 2 levels - MAP and RAP. MAP estimates consider customer adoption of economic measures when delivered through DSM programs under ideal conditions and an appropriate regulatory framework. RAP reflects program participation given DSM programs under typical market conditions and barriers to customer acceptance and constrained program budgets. IPL used the MAP measure estimates to construct the DSM bundles input into the IRP optimization modeling. NIPSCO used a Program Potential based on cost-effectiveness analyses at the measure level by MMP using the screening tool DSMore. Measures that came out of this analyses were combined into bundles by end-use and load shape. IPL also used MMP "to create the DSM bundles using the DSMore cost-effectiveness model."

It appears that NIPSCO used a more conservative version of Achievable Potential than IPL on which it based the DSM bundles. NIPSCO defined Achievable Potential as refining the Economic Potential by applying customer participation rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that affect market penetration of DSM measures (p. 77). As noted above, IPL used MAP to develop bundles, and MAP estimates consider customer adoption of economic DSM measures under ideal market, implementation, and customer preference conditions, and an appropriate regulatory framework. It would appear that NIPSCO was more conservative because its definition of Achievable Potential is probably closer to IPL's RAP rather than MAP.

2. IPL and NIPSCO both developed bundles by grouping measures by sector, end use, and similarity of load shape. However, IPL went one step further and disaggregated its bundles by the direct cost to implement per MWh. The three price tiers were: up to $30/MWh, $30-60/MWh, and $60 plus/MWh. As IPL noted, creating cost tiers addresses the issue of having highly cost-effective measures lumped into bundles with marginally cost-effective measures. Such a structure could result in some cost-effective measures not being selected. NIPSCO recognizes the potential problem of mixing higher cost and lower cost DSM measures in the same bundle.

Perhaps the most difficult area to compare and try to draw conclusions is how the cost of the bundles were developed by each utility and how the cost varied both across bundles and within the same bundle over the forecast period. CAC et al. expressed concerns the DSM bundle methodologies implemented by each of the utilities required a forecast of DSM bundle cost and performance trajectories over a 20-year period regardless of the specific cost projection methodology used. Vectren used an approach for bundle cost projections that was very different from that implemented by NIPSCO and IPL.

8.4. Metric Definitions and Interrelatedness

The Director appreciates the development and implementation of metrics used by the utilities in their respective IRPs. Our primary interest is to enter into a conversation to further everyone's understanding of the usefulness of individual metrics and how to best consider the metrics and the story they tell in a holistic manner. Clearly some metrics are more directly relevant to the specific risk being evaluated than others and that needs to be better understood. Another issue is how metrics are weighted. Should all risk measures be weighted equally or are there circumstances where a different weighting is reasonable? Also, some of the metrics probably need to be more clearly defined in a narrative so that their limitations and strengths can be better understood. Lastly, the interrelationships between various measures needs to be more fully understood. That is, are some redundant, are some telling the same story from different perspectives, and are other measures more appropriately evaluated only when also considering other metrics? What are the limitations and strengths of using a scorecard based on informed judgment to evaluate the performance of various resource portfolios across a diverse range of potential futures?

Examples of clearer and more specific definitions can be found in the PJM Interconnection report titled "PJM's Evolving Resource Mix and System Reliability," published March 30, 2017. PJM notes,

> *Fuel diversity in the electric system generally is defined as utilizing multiple resource types to meet demand. A more diversified system is intuitively expected to have increased flexibility and adaptability to: 1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility and fuel supply disruptions, and 3) reliably mitigate instabilities caused by weather and other unforeseen system shocks. In this way, fuel supply diversity can be considered a system-wide hedging tool that helps ensure a stable, reliable supply of electricity. (p. 8)*

PJM also says diversity consists of three basic properties: variety, balance and disparity. As each of these properties increase, diversity also increases. PJM defines the characteristics of diversity as:

- Variety is a measure of how many different resource types are on the system. A system with more resource types in its generation mix has greater variety.
- Balance is a measure of how much grid operators rely on certain resource types. Balance increases as the reliance on different resource types in a generation mix is becoming more evenly distributed.
- Disparity is a measure of the degree of difference among the resource types relative to each other. Disparity can relate to the geographic distribution of resource types – generation resources that are evenly distributed across the system are more disparate than concentrated pockets of generation resources. Disparity also relates to operational characteristics of resources – a system with resource types that have different operational characteristics is more disparate than a system with in which all of the resource types have similar operational characteristics. (p. 9)

PJM also defines resilience differently than how this term is used by IPL in its risk metric discussion.

The Director recognizes that the metrics and definitions developed for a region as large as a RTO may not be applicable to a single utility, but the specificity in the definitions used by PJM is worthy of emulation where appropriate. Also, the PJM report makes clear that the relationship between diversity and reliability is not linear. More generally, the costs, benefits, and reliability values of fuel and resource diversity is dynamic and extremely important. Future IRPs should devote considerable attention to developing and interpreting different risk metrics and should be informed by experts and stakeholders.

A critical objective should be a robust or resilient plan. How is this defined? How should it be measured? The utilities seem to be using different definitions but a key common aspect is exposure to the wholesale power market. More specifically, exposure beyond some undefined level is generally thought to be bad but there seems to be little recognition, except for NIPSCO, that length of commitment to a specific resource – particularly one that is capital intensive and long-lived can also be a problem. Steel in the ground eliminates market exposure in a sense but has the downside that the costs are sunk and thus are probably exposed to the highest degree of technological risk. Again, a more detailed discussion of the uncertainties, risks, and ramifications of fuel and resource diversity under a variety of scenarios would be helpful.