<u>**INDIANA UTILITY REGULATORY COMMISSION**</u>

ELECTRICITY DIRECTOR'S
FINAL REPORT
2014 - 2015 INTEGRATED RESOURCE PLANS
SUBMITTED BY
IPL, NIPSCO, VECTREN,
AND HOOSIER ENERGY

Date of the Report: June 10, 2015

ELECTRICITY DIRECTOR'S FINAL REPORT

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A. INTRODUCTION AND BACKGROUND

With the passage of P.L. 246-2015 (SEA 412-2015) on May 6, 2015, Indiana law now explicitly requires long-term resource planning for the State of Indiana. For the Integrated Resource Plans (IRPs) submitted on November 1, 2012, the utilities voluntarily adhered to the Draft Proposed Rule (Proposed Rule) to modify 170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans (RM 11-07). The Indiana Utility Regulatory Commission (IURC or Commission), utilities, and stakeholders collaboratively developed the Proposed Rule, which is available on the IURC website at http://www.in.gov/iurc/2674.htm.

Four Indiana utilities submitted their IRPs on November 1, 2014. Links to the IRPs and the utilities' comments regarding the Director's Draft Report http://www.in.gov/iurc/files/IRP_2015_Draft_3-3-15.pdf and other stakeholders' comments are included below. Please note these are the public versions and do not include confidential information and most appendices:

1. Indianapolis Power & Light Co. (IRP)
   http://www.in.gov/iurc/files/IPL_2014_IRP_Report.pdf

   Comments on the Draft Director's Report http://www.in.gov/iurc/files/IPL_Comments.pdf
2. Northern Indiana Public Service Co. (IRP)
   http://www.in.gov/iurc/files/NIPSCO_2014_IRP.pdf

   Comments on the Draft Director's Report
   http://www.in.gov/iurc/files/NIPSCO_Response_to_Draft_Report_Submitted_April_2_2015.pdf
3. Southern Indiana Gas & Electric Co. (Vectren) (IRP) http://www.in.gov/iurc/files/SIGECO-Vectren_2014_IRP_Report.pdf
   Comments on the Draft Director's Report
   http://www.in.gov/iurc/files/Vectren_Comments.pdf
4. Hoosier Energy (IRP) http://www.in.gov/iurc/files/Hoosier_Energy__IRP_-_44559_-_Public_Version_-_Volume_I.pdf
   Comments on the Draft Director's Report
   http://www.in.gov/iurc/files/Hoosier_Comments.pdf

Written comments regarding the IRPs and the Director's Draft Report were also submitted by various entities, including:

1. Citizen Action Coalition Comments on the Draft Director's Report
http://www.in.gov/iurc/files/CAC_EJ_SC_IndianaDG_VW_Comments_of_2014_IRP_Draft_Report--4-16-15.pdf

2. Earthjustice (see Stakeholder Commenters)

3. Sierra Club (see Stakeholder Commenters)

   Prepared by Synapse Energy Economics, Inc. http://www.in.gov/iurc/files/Comments of Sierra club re IPL.pdf

4. Hoosier Environmental Council
http://www.in.gov/iurc/files/Comments_of_Hoosier_Environmental_Council_re_Vectren_IPL_NIPSCO(2).pdf

5. Office of Utility Consumer Counselor
http://www.in.gov/iurc/files/Comments_of_OUCC_re_Vectren_South_IPL_NIPSCO_Hoosier_Energy(3).pdf
Comments on the Draft Director's Report http://www.in.gov/iurc/files/IRP_-_OUCC_Comments_-_IURC_Draft_Report__4-16-15_.pdf

6. Valley Watch http://www.in.gov/iurc/files/Comments_John_Blair_-_Vectren.pdf

7. Jean Webb http://in.gov/iurc/files/Vectren_South_Electric_Customer_J_Webb.pdf

8. Mark Bryant http://www.in.gov/iurc/files/Mark_Bryant_Valley_Watch.pdf

9. Joint Utility Commenters (IPL, NIPSCO, Vectren) Comments on the Draft Director's Report
http://www.in.gov/iurc/files/IPL_NIPSCO_Vectren_Joint_Comments.pdf

10. Stakeholder Commenters (Distributed Energy Alliance, Sierra Club – Hoosier Chapter, and Valley Watch)
http://www.in.gov/iurc/files/Comments_on_IPL_Vectren_NIPSCO_2014_IRPs_with_Exhibits-1-30-15-Redacted(2).pdf

The initial written comments were included in the Director's Draft Report, which was issued on March 3, 2015.

Section 2 (h) of the Proposed Rule requires the Electricity Director to issue a Draft Report on the IRPs no later than 120 days from the date a utility submits an IRP to the Commission. Section 2(k) of the 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 Proposed Rule restricts the Director from commenting on the utility's preferred resource plan or any resource action chosen by the utility.

Consistent with the Proposed Rule, this Final Report was issued within 30 days following the extended deadline for submitting supplemental or response comments.

The Importance of the IRP Process

While every major business dedicates substantial effort to forecasting demand for their products and planning to meet their customers' needs, few industries are as important as the electric system, which has been called the most complex man-made system in the world. Because of the critical importance of the industry, state-of-the-art planning processes are essential. The need for continual and immediate improvements is heightened by the risks resulting from significant changes due to aging infrastructure, increasingly rigorous environmental regulation, substantially reduced costs of natural gas, a potential paradigm change resulting in long-term low load growth, declining costs of renewable resources, and technologies including combined heat and power. The Proposed Rule anticipates continual improvements in all facets of the planning processes of Indiana utilities. The Director believes utilities have made substantial progress but, given the importance of long-term resource planning, much work remains to be done.

As with the prior Draft Director's Report, this Final Report also places considerable emphasis on the importance of robust risk analysis in IRPs. The Director has encouraged the utilities, in collaboration with their stakeholders, to develop scenarios and sensitivities that not only plan for a likely future but also assess the ramifications for a future with lower probability scenarios and sensitivities with possible high potential costs. To encourage utilities to undertake a more robust consideration of risk, the utilities are welcome to caveat their risk analyses, particularly those having a low probability, as being unlikely or other similar qualifying terms or phrases. In all instances, the Director urges utilities and stakeholders to develop an internally consistent narrative of all aspects of the IRP. This Final Report will, then, have greater emphasis on load forecasting because of its integral relationship with the long-term resource plans of each utility. Consistent with the previous Draft Director's Report, this critique will also stress the importance of stakeholder input, assessing the potential for new technologies, and increasingly sophisticated critical thought to the long-term potential for energy efficiency, demand-response, renewable energy resources and other distributed generation.

As a general observation, the Director believes that these IRPs represent an improvement over their prior IRPs. The commitment of the Chief Executive Officers and subject matter experts is commendable, the stakeholder processes were much improved. Utilities gave more appropriate recognition to the integration of the IRPs with the regional planning processes of the Regional Transmission Organizations. All of the utilities had an improved characterization of the significant risks they are likely to confront, including environmental risks, a potential paridigm change in customer usage resulting in long-term low load growth (maybe negative), lower cost trajectories for future gas costs and costs of renewable and other customer-owned resources. There was increased attention given to the difficult problem of treating DSM as a resource and the utilities' retention of outside experts to assist with the DSM analysis is also commendable. However, the IRP is evolutionary and the expectation is for continual improvements in tools, processes, and analysis in response to increased risks and attendent costs. Hopefully, future IRPs will provide a more detailed vision of enhancements to their planning processes. The Director wishes to express gratitude to the utilities and stakeholders that participated in the process; particularly those that offered comments.

B. PRIMARY ISSUES IN THE IRP PROCESS; UTILITIES', STAKEHOLDERS' AND DIRECTOR'S RESPONSES

The first section of this Report contains a summary of the primary issues that are addressed through the IRP process, and highlights the utilities' and stakeholders' comments. The Director's comments and responses are designed to serve as guidance to the utilities.

1. STAKEHOLDER PROCESS

IPL, NIPSCO, and Vectren (Joint Utility Commenters) correctly noted "ultimately, the question becomes 'what is the purpose of the IRP public advisory process?'"

The Director agrees with the Joint Utility Commenters that they are primarily responsible for developing their utilities' "Plan." This preferred Plan might be the base case. The base case should describe the utility's best judgment (with input from stakeholders) as to what the world might look like in 20 years if the status quo would continue without any unduly speculative and significant changes to resources or laws/policies affecting customer use and resources. Utilities may also wish to construct alternative scenarios and sensitivities that provide useful insights and information about a broad spectrum of possible and significant variables regarding future load and resource requirements.

However, the Director makes a distinction between the utilities' Plan and the overall IRP process. The IRP requires meaningful stakeholder input. Ideally, the utilities would consider and, where the utility deems appropriate, include stakeholder input into the construction of their Plan. It is the intent of the proposed IRP Rule to ensure meaningful participation by stakeholders. To this end and for the sake of credibility, each utility should afford stakeholders the opportunity to work collaboratively with the utility to construct alternative scenarios and sensitivities.

The Director trusts that the utilities understand the Commission's statutory obligation to ensure reliable and economic electric service. To satisfy the statutory requirements, the Commission needs to have confidence in the credibility of the Integrated Resource Plans and the processes. In promulgating the IRP Rule and because of the importance of the analysis for a wide range of issues, the Commission provided a meaningful role for stakeholders that participate in the IRP process. The Director hopes the Joint Utility Commenters will recognize the mutual benefits of having informed stakeholders and an informed Commission. As with all aspects of the IRP Rule, continual improvements are anticipated and encouraged.

Perhaps the most gratifying aspect of the IRP process has been the continual improvements in the stakeholder process. All of the utilities made a concerted effort to encourage participation and there were significant numbers of people that attended or participated by phone (a range of 30-60 people was common). Unfortunately, despite the efforts of utilities, few large customers participated. Increased participation by commercial, industrial, and local government would enhance the IRP process. Utilities, generally, also had one-on-one conversations with some stakeholders and in some instances utilities conducted conference calls with multiple stakeholders. In short, the utilities went to considerable effort to provide access to the meetings. Without exception, the utilities' top officers and subject matter experts attended the sessions, which provides strong evidence of the utilities' commitment to their IRP processes. The utilities were gracious hosts and provided good information that benefited the process.

An important purpose of the IRP process is to expedite the construction and/or acquisition of all forms of cost-effective resources and to do so with less acrimony by having utilities, stakeholders, and Commission better understand the decisions and the alternatives. The Director believes better mutual understanding will enhance public confidence in the decision-making processes. Because the IRP analysis is complex, controversial, and difficult, it is important to have on-going education. To this end, the Director recommends the Commission accept the Joint Utility Commenters' proposal to discuss the type of on-going education that would enhance the IRP process without it being an undue burden on the utility and its IRP process.

CEO Comments at the 2015 Summer Reliability Forum In response to questions from Commissioners and Consumer Counselor David Stippler, all of the utility Chief Executive Officers (CEOs) expressed support for improving all aspects of the IRP stakeholder process; including continuing efforts to encourage commercial and industrial customer participation, improving the conduct of the forums, and providing mutually beneficial education. In response to questions from Consumer Counselor Stippler, there seemed to be agreement that stakeholders should have input into the development of the base case and the scenarios and sensitivities that are needed to assess alternative futures. The CEOs all recognized that meaningful stakeholder involvement was necessary for a successful IRP effort and recognized that this effort was subject to continual improvements. All of the utilities CEOs articulated the significant long-term risks and expressed support for the IRP process to assess those risks. Jim Stanley, CEO of NIPSCO, emphasized that no one involved in the process should attempt to use the IRP process to achieve a pre-determined outcome (e.g., shutting down all of the coal-fired facilities). The Director agrees that a well-designed planning process, with robust selection of scenarios and sensitivities, should allow the planning models to solve for the most reliable, resilient, and economic solutions rather than preferred or hardwired outcomes.

Joint Utility Commenters (IPL, NIPSCO, and Vectren) "[T]*he Commission staff encourages an expanded role for stakeholders in the development of the IRP. The Draft Report suggests that at the outset of the stakeholder process, the IOUs should facilitate the collaborative work among the utility and its stakeholders by discussing goals, providing an overview of the current system and how planning is done including the drivers of the load forecasts… The IOUs have an obligation to provide reliable service to customers that they take very seriously and resource planning is a key part of supporting this role. Thus, while stakeholder input on this process is positive, ultimately it cannot become burdensome or be allowed to interfere with successful resource planning… [T]he IRP is ultimately the responsibility of the utility alone…"* page 3 of IPL's, NIPSCO's, and Vectren's Joint Comments.

2. RISK ANALYSIS

The Director agrees with the Joint Utility Commenters that the individual Plan endorsed by a utility for this IRP cycle should reflect the utility's best judgment. However, the Director believes a credible Integrated Resource Planning process will have an expansive analysis of potential risks surrounding the utilities' plans in their development of unique futures using well-reasoned scenarios and sensitivities. Consistent with the Commission's statutory requirements for ensuring reliable and economical service, utilities should assess the resource ramifications of an expansive risk analysis that includes scenarios and sensitivities with a broad range of risks with well-reasoned narratives. The range of risk analysis should include both those events the utility regards as high probability events as well as relatively low probability events that have significant potential implications for affecting the delivered cost of electricity to customers and/or for reliability. The Director encourages utilities to enlist the input of stakeholders in the construction of scenarios and sensitivities. Of course, the utility has the discretion to accord alternative scenarios and sensitivities with a weight they deem to be appropriate and to characterize them accordingly. Correspondingly, the Commission has the obligation to weigh the utility analysis.

The Director also agrees with the Joint Utility Commenters that the IRP process should be regarded as evolutionary. The Director believes IRPs should strive for being state-of-the-art. Consistent with the intention of the IRP process to encourage continual improvement in all aspects of the IRP process and analysis, the Director encourages the utilities to consider new and innovative approaches to risk analysis. These tools and processes need not be viewed as alternatives. Rather, at a minimum, alternative approaches should be considered as supplemental or complementary.

CEO Comments - 2015 Summer Reliability Forum Utility CEOs enumerated several potential risks that confront the industry generally and their utilities specifically. In addition to the significant potential risks from increasingly stringent environmental regulations, the CEOs noted several other factors including, but not limited to, the projected relatively low-cost natural gas costs, low load growth, aging generation and other infrastructure, uncertain economic growth, regional resource considerations, declines in the cost of technologies such as wind, solar, and the potential for large customers to install combined heat and power.

Joint Utility Commenters (IPL, NIPSCO, and Vectren) "*The purpose of the IRP is to provide a snapshot in time of how the utility plans to meet customers' long term electric needs and the utility's assessment of the need for new resources. It is costly and time consuming with little to be gained to prepare extensive analysis at a time when no decision relative to resource additions is being made or for outcomes that have a very low probability of occurring."* page 4 of IPL's, NIPSCO's, and Vectren's Joint Comments. "*The Draft Report also invites utilities and stakeholders to consider having 'reasonably consistent definitions of important concepts.' Draft Report at 3. A technical conference to discuss the Commission staff's understanding of these terms would be beneficial. Conventional thinking on the terms ascribe[d] the following meaning:*

- *A scenario is a simulation of a future world technical, regulatory, and load environment.*
- *A sensitivity is a case run against a specific scenario varying only one element such as fuel prices.*

It is feasible that the same resource plan is chosen across various scenarios and sensitivities. This does not mean that the analysis is flawed. In fact, it adds certainty to decision making." page 4 of IPL's, NIPSCO's, and Vectren's Joint Comments.

OUCC Comments The OUCC stated: "*The utilities did not demonstrate in a clear manner whether these qualitative elements [e.g., political outlook, risk, portfolio mix, and human behavior] were considered and, if so, how they were accounted for in the modeling process."* page 1 of the OUCC Comments.

<u>Distributed Energy Alliance, Sierra Club – Hoosier Chapter, and Valley Watch (Collectively, "Stakeholder Commenters")</u> *"The Stakeholder Commenters agree with the Draft Report that 'robust risk analysis' are of considerable importance to the integrated resource planning process. We also echo the Draft Report that such risk analysis must examine a broad range of scenarios and sensitivities, that long-term resource decisions should not be "baked-in" to the IRP process, that meaningful opportunities for stakeholder involvement are critical, and that the designation of information as confidential should be limited and, where such designation is appropriate, proxy information should be provided.*

However, the Stakeholder Commenters take issue with the Director's Report:

- *Remove the suggestion that forecasts of environmental compliance costs be treated differently from forecasts of all other variables;*
- *Recommend that forecasts of environmental compliance costs be included in the base case if they are 'expected,' which is the same standard Staff proposes for other variables;*
- *Clarify that while the forecasted costs for compliance with the Clean Power Plan could not have been included in the 2014 IRPs, forecasted costs to comply with carbon regulations could and should have been included in the base case;*
- *Specify when forecasted environmental compliance costs are 'expected' and should therefore be included in the base case;*
- *Remove references to alternative scenarios and sensitivities as automatically being merely 'illustrative' and 'low probability';*
- *Recommend that utilities analyze the optimal mix of existing and new resources rather than assume that existing resources will continue to operate;*
- *Identify examples of probabilistic analyses that Staff have in mind when they recommend the use of probabilistic methods;*
- *Recommend that avoided cost analyses look beyond short-term marginal costs and include a comprehensive evaluation of the full suite of avoided costs and risk mitigation.*

We suggest that instead of using a different standard for inclusion of environmental compliance costs in the base case, Staff should define what it means for an environmental regulation to be 'expected.' We propose the following definition:

- *Environmental compliance costs are 'expected' if, at the time an IRP is developed, the anticipated compliance period falls within the time period analyzed in the IRP, and any of the following conditions is true:*

(1) *a state or federal agency has issued a proposed rule or notice of proposed rulemaking; or*

(2) *a state or federal agency has announced or a court has established a deadline for issuance of a final rule; or*

(3) *the utility has evaluated compliance options and costs for a potential future environmental standard as part of its internal planning processes."* page 5.

Director's Response to Joint Utility Commenters The Director agrees with the Joint Utility Commenters' general comments on page 4 about scenarios and sensitivities providing they are interpreted in an expansive manner. For example, an IRP scenario would also include fuel costs, capital costs, economic drivers, customer-owned resources, etc.:

- *"A scenario is a simulation of a future world technical, regulatory, and load environment.*
- *A sensitivity is a case run against a specific scenario varying only one element such as fuel prices."*

In theory, the Director accepts the Joint Utility Commenters assertion that "*It is feasible that the same resource plan is chosen across various scenarios and sensitivities. This does not mean that the analysis is flawed. In fact, it adds certainty to decision making."* However, the Director believes that this outcome is unlikely for scenarios and sensitivities that are based on a robust risk analysis. Moreover, while we understand the point that reaching the same conclusion using different analysis *"adds certainty to decision making,"* we suggest the same argument can be made for making greater use of probabilistic analysis to supplement current analytical methods. However, neither utilities nor stakeholders should intentionally construct the base case, scenarios, or sensitivities to arrive at a predetermined or desired resource outcome. Rather, utilities and stakeholders should agree that having significantly different – but plausible – drivers for scenarios and sensitivities provides the most meaningful information.

Director's General Response to the OUCC The Director agrees with the OUCC's qualitative risks as well as the risks that can be quantified, although they were not always as clearly articulated. Again, the Director recognizes this is an evolutionary process.

Director's Response to Stakeholder Commenters From the Director's perspective, a base case should be the utility's best judgment of the future but, for the sake of credibility and to ensure that stakeholders' input is meaningful, the utilities should give due consideration to the stakeholder's input.

The Director gives considerable deference to the utility's authority to develop "their" Plan. However, to avoid – or at least mitigate – controversy, it would seem to be prudent for the utility to obtain stakeholder input into the development of their Plan.

While the Director, according to the Draft Proposed Rule, accords considerable latitude for the utility to use their judgment on what should be included in their Plan, this does not mean that the utility's Plan should not be subject to critique. For example, a Plan that is also the base case that includes changes in infrastructure that does not have a high degree of certainty (e.g., perhaps within 3 to 5 years) may be subject to challenge as unreasonable since there may be time to consider alternative resources. That is, the planning process should not preempt consideration of alternatives that may be more efficacious and/or cost effective. On the other hand, the long-term load forecast that the utility deems to be most likely should be included in the base case and the utilities Plan; with the understanding that continual efforts will be made to improve the credibility of the load forecasts. For this round of IRPs, each utility took a different approach to the Proposed Draft Clean Power Plan's (CPP) CO_2 costs. In all instances, the decision to include or exclude CO_2 costs or to treat them in different ways was a matter of their expert judgment as to the degree of certainty about the timing and ramifications of the Clean Power Plan. However, a common failing was a lack of a well-reasoned narrative to explain their treatment or to construct a robust risk analysis of the potential ramifications of the proposed Clean Power Plan.

The Director agrees with the utilities that extensive analysis of the ramifications of the Clean Power Plan have been undertaken by MISO, PJM, and others. The results have varied considerably depending on the assumptions. However, if a utility or all utilities agree with the Stakeholder Commenters' proposed definition of "expected," the Director does not object to the Stakeholders' suggestion "*that instead of using a different standard for inclusion of environmental compliance costs in the base case, Staff should define what it means for an environmental regulation to be 'expected.' We propose the following definition: Environmental compliance costs are 'expected' if, at the time an IRP is developed, the anticipated compliance period falls within the time period analyzed in the IRP, and any of the following conditions is true: (1) a state or federal agency has issued a proposed rule or notice of proposed rulemaking; or (2) a state or federal agency has announced or a court has established a deadline for issuance of a final rule; or (3) the utility has evaluated compliance options and costs for a potential future environmental standard as part of its internal planning processes.*" page 5 of Stakeholders' Comments.

While the importance of the base case should not be understated, the Director believes the Stakeholder Commenters' concern for treatment of environmental regulatory costs (or some other important variables such as the cost of renewable resources or customer-owned resources) is more appropriate for the construction of alternative futures as defined by their scenarios and their sensitivities. Utilities should, in concert with stakeholders, consider plausible scenarios and sensitivities that might be characterized as "bookends" to better recognize the breadth of risks and attendant costs of uncertainty. Again, the Director believes a variety of scenarios and sensitivities that entail reasonable probabilities as well as those that have relatively low probabilities but significant ramifications should be analyzed. The construction of a robust risk analysis is, in the Director's perspective, essential and this is a major focus of the critique.

From these IRPs, it is clear that utilities are hesitant to undertake an expansive analysis of potential risks and assess their consequences. To encourage utilities to consider a more robust portfolio of risks through scenarios and sensitivities, the Director believes the utility should be able to characterize these as "low probability." Nevertheless, the combination of scenarios should be reflective of the perceived range of uncertainty. The concept is to move away from excessive consideration of what is thought most probable now and to put more emphasis on consideration of what is possible, and what the range of uncertainty says about the efficacy of different resource decisions.

To reiterate, each of the scenarios and their sensitivities should have a narrative that is internally consistent and within the realm of possibility but may be relatively low likelihood but with significant ramifications. Since trying to optimize these decisions, to the extent reasonably feasible, is a difficult undertaking, the Director urges utilities to adopt state-of-the-art planning tools, processes, and databases. Consistent with the evolutionary process of IRPs, such consideration should include an expanded use of **probabilistic methods as a supplemental analysis rather than an alternative**. With increased computing capabilities and software, it is increasingly possible to optimize two or more resources. Improved databases are essential to effectively utilize the capabilities of advanced software.

Consistent with the Director's encouragement for utilities to collaboratively undertake a more comprehensive assessment of potential risks and to do so using a variety of methods, we agree with the Stakeholder Commenters that avoided cost analyses should look beyond short-term marginal costs and include a comprehensive evaluation of avoided costs.

The Director agrees with Stakeholder Commenters "*All forecasts are predictions about an uncertain future — predictions which may turn out to be wrong. To take one example, very few, if any, utilities predicted the last recession and the dramatic decline in load that accompanied it. Similarly, very few, if any, utilities predicted the dramatic drop in natural gas prices caused by the shale gas boom. Forecasts of fuel prices, load, and other variables can, and often do, deviate significantly from the eventual reality.*" It is precisely for the reasons that are well-articulated by the Stakeholder Commenters that the Director encourages utilities to undertake robust risk analysis, make on-going improvements to the IRP process, and consider supplementing existing analytical tools and methods with probabilistic tools and analysis. Stakeholder Comments, page 3, April 16, 2015.

3. DEVELOPMENT OF SCENARIOS

The base case would be regarded as the status quo case that includes only known events and expected trends (e.g., forecast of fuel prices, economic forecasts, estimated future capital costs, most expected load forecast). The base case should describe what the utility (with input from stakeholders) would expect the world to look like in 20 years if the status quo would continue without any unduly speculative and significant changes to resources or laws/policies affecting resources that aren't known and measurable (at least to construct reasonable sensitivities). That is, to avoid concerns that resource decisions are predetermined or "baked in," the base case should not include a preferred portfolio of resources beyond those with a very high probability of being implemented in a relatively short time period (perhaps 3 to 5 years). The narrative for the base case should also discuss the anticipated uncertainties that would be addressed in scenarios and sensitivities. It would not be unreasonable for a base case to exclude federal or state legislative or regulatory changes where the timing of implementation and the ramifications are very speculative even if the regulations have a high degree of probability of being implemented. At the time of the 2013 and 2014 IRPs, for example, it might have been reasonable for the base case not to include the Clean Power Plan rules for carbon dioxide since the timing and implementation ramifications were very uncertain despite the likelihood that the regulations would be implemented at some point. However, it would be reasonable to expect utilities to construct at least a couple of scenarios and related sensitivities that would attempt to bracket the potential risks of the Clean Power Plan rule.

The development of alternative possible futures to the base case is done through the development of scenarios and sensitivities. These alternative scenarios are intended to evaluate a broad range of plausible risks with varying magnitudes and probabilities (such as varying load requirements, different fuel price projections, a range of environmental regulatory costs, a range of the cost of various technologies, etc.) and assess the potential ramifications of those risks. For credibility and usefulness, each scenario and its sensitivities should tell a distinct and well-reasoned story that likely results in a different resource mix.

The Director hopes utilities and stakeholders do not regard our critique as being prescriptive. Rather, we hope our suggestions are regarded as encouraging a more comprehensive assessment of potential futures as part of an on-going evolution of the IRP process. The Director believes it is mutually advantageous for utilities and stakeholders to collaboratively develop the scenarios and sensitivities to foster a meaningful stakeholder process. Moreover, while the development of the utility's "Plan" is the responsibility of the utility, the Director believes there are benefits to the utility and its stakeholders for collaboration in all aspects of the IRP process. A collaborative process in the construction of the base case and alternative scenarios and sensitivities can enhance the credibility of the results.

Director's Response to Joint Utility Commenters The Director, in general terms, accepts the first two bullet points provided they are sufficiently expansive. For example, the Director presumes the Joint Utility Commenters would include economic drivers. However, the Director has reservations about the Joint Utility Commenters statement on page 4 "*It is feasible the same resource plan is chosen across various scenarios and sensitivities. This does not mean that the analysis is flawed. In fact, it adds certainty to decision making.*"

As a theoretical matter this may be an accurate statement especially for relatively short run analysis with a limited spectrum of risks. However, for a 20-year-planning horizon for Indiana utilities that are examining a robust set of scenarios and sensitivities (including different assumptions of load growth, environmental costs, fuel costs, technological costs, etc.), it seems unlikely that different scenarios and sensitivities would have the same resulting resource mix. More importantly, from a planning perspective, having multiple scenarios that are too narrowly constructed and result in similar resource mixes does not provide utility decision makers, policymakers, or stakeholders as much useful information about the ramifications of potential risks and the options available to the utility to mitigate those ramifications.

4. ENERGY EFFICIENCY AND DEMAND RESPONSE DSM

The Director recognizes the difficulty of treating Demand Side Management (DSM) in a manner that is comparable to traditional generating resources. However, since the utilities, stakeholders, and Director all agree on the importance of DSM (Energy Efficiency-EE and Demand Response-DR) for meeting both short-term and long-term resource requirements, a concerted effort must be made to ensure that all cost-effective DSM is considered in the formulation of each utility's IRP.

CEO Comments - 2015 Summer Reliability Forum All of the CEO's emphasized the importance of Energy Efficiency and Demand Response as an integral component of their shorter-term and longer-term resource plans; especially with the passage of SEA 412. Integrating demand side management into the IRP process was considered to be essential to the success of IRPs and the inclusion of cost-effective DSM into the resource mix of Indiana utilities. The potential for DSM as an element in satisfying aggressive compliance requirements for the Clean Power Plan rule was also mentioned by CEOs.

__**Joint Utility Commenters**__ **"***The Draft Report expresses concern that a number of assumptions were 'baked-in' or 'hardwired' to the IRP process rather than using modeling to select appropriate resources. __Draft Report at 7__. While each utility will address concerns with its own IRP, generally speaking there are valid reasons why the analysis was handled as it was… it should be noted that all of the electric utilities consider DSM programs a planning resource comparable to supply resources. This is true whether the utility uses the California standard tests (TRC, UCT, PCT and/or RIM) from multiple planning objectives (cost effectiveness, rate impacts) versus supply resources, or in a production cost simulation model. Each method has its advantages. In either case, DSM causes a reduction in the load that then needs to be served by supply resources. The term 'baked in' or 'hardwired' implies that DSM integration is done without a resource planning evaluation and selection process. This is not the case. In short, the best planning models take into account certain specifics that are known or the utility wants to be achieved while allowing the model to select options that are outside of those known variables. In the case of DSM, it is appropriate to create a resource plan with some level of DSM included to ensure the on-going availability of programs for reasons such as customer acceptance, program delivery and customer satisfaction."* page 5 of Joint Utility Comments.

__**Director's Response to Joint Utility Commenters**__ Integrating DSM into the IRP is, admittedly, difficult. However, the treatment by utilities in this round of IRPs suggests that DSM may have been *hardwired* to varying extents. This is based on comments from the Joint Utility Commenters, combined with the fact that some DSM was held constant across multiple scenarios where the circumstances that reflect increased costs for new or retrofitted resources would, in all probability, result in greater amounts of DSM (both energy efficiency and demand response). Among other things, the Director understands, for example, that utilities bundle (package or pre-process) DSM into groups of DSM programs outside of the generation expansion planning model. If the bundling of various DSM programs is not done with care and sufficient detail, an unintentional bias may result which would cause the capacity expansion planning model to not pick DSM even though a more careful packaging of DSM might have resulted in its inclusion. While bundling DSM into discrete packages is appropriate, it is important that the details and the level of granularity be as comparable as possible to generating options to provide greater assurance that DSM and other resource options are treated as comparably as reasonably possible. The Director is concerned that this separate treatment creates a "separate but unequal" evaluation that may have other consequences. For example, treating DSM as a load reduction and saying it's treated as a resource requires a more detailed explanation. This is not merely an academic point because of the implications for resource adequacy and other ramifications, especially where DSM stays the same across scenarios.

5. CUSTOMER-OWNED AND DISTRIBUTED GENERATION

The Director recognizes that absent definitive information from customers, it is difficult to estimate the amount and timing of new or modified customer-owned generation. There seems to be growing acceptance that customers may calculate the benefits and costs differently than the utility. Given the importance of large customers, customer-owned generation such as combined heat and power is a significant risk that needs to be considered in the IRP process.

Joint Utility Commenters "...[U]*tilities constantly interact with large customers and apply what is learned in the forecast for both the short- and long-term. While the narrative could possibly be strengthened to make this clearer, the IOUs do interact with their customers and find that information invaluable in planning efforts. The Draft Report goes on to recommend that the utilities use end-use information by North American Industry Classification System (NAICS) in preparing the forecast. In talking about tailoring rates and other offerings to customers, it appears that the scope of the IRP is morphing into consideration of rate case issues. The IOUs recognize the need to plan based on the various customer classes, but tailoring rates is not an appropriate discussion for a planning document. The Draft Report notes that 'without exception, the utilities could have done more to explain their forecasting methods and how they are integrated to develop a cohesive company forecast and narrative*.' *The utilities will be mindful of this recommendation in the preparation of future IRPs."* page 6 of Joint Utility Comments.

Director's Response Again, the Director was gratified that the CEOs of all the Indiana utilities that addressed customer-owned generation during the 2015 Summer Reliability Forum recognized the potential risks of customer-owned generation and the possible ramifications for their customers. The CEOs also stressed it was difficult to anticipate a customer's decision to install their own resources because the decision may not be consistent with the utility's understanding of the benefits and costs.

6. INTERRELATION OF RATES WITH THE IRP

The Director vigorously disagrees with the Joint Utility Commenters when they state that it is not appropriate to discuss rates and rate designs in a resource planning document. The design of rates is critically important since that is the primary means by which a utility conveys information about the cost of electric service to customers. Rates can encourage consumption at some times and discourage consumption at other times; rates also impact customer decisions to acquire appliances or equipment with varying characteristics. Rate design is also of paramount importance when evaluating the cost effectiveness of demand response. In fact, the current DSM rules recognize innovative rate design as a DSM resource (See 170 IAC 4-7-6 (b)).

C. DIRECTOR'S GENERAL COMMENTS REGARDING THE IRP PROCESS

Every utility should:

1) Include a discussion within the IRPs on how they intend to make continual improvements to the IRP process, the databases, and the analytical tools. Utilities should consider:

   a. Methods for enhancing the stakeholder participation and obtaining meaningful input;

   b. Regular updates of DSM (energy efficiency and demand response) potential and improvements to the methods for integrating DSM into the planning process;

   c. Incorporation of different means for assessing risk and integrating risk into the utility's planning process;

   d. Coordination with their Regional Transmission Organization in matters of resource planning and operations. <u>The Director requests that utilities provide the same information on resource adequacy to the Commission that utilities provide to their RTO(s).</u> Additionally, to the extent that RTOs facilitate compliance with environmental regulations, the Director requests that utilities provide a discussion of the utilities' participation in the program and the effect on the IRP;

   e. The use of new technologies, such as Smart Grid and Advanced Metering Infrastructure that may enhance the quality or quantity of information available for use in the IRP process; and

   f. Methods for better forecasting of distributed and customer-owned generation.

2) To the extent possible, utilities should provide all of the relevant information in the public version of the IRP. If proprietary or confidential information is used in the utility's IRP analysis, the utility should provide a discussion of the information in the public version and a more detailed discussion of the information and the relevance in the confidential version of the IRP. That is, the Director should not have to search for information in an appendix or a confidential supplement that was an important element of the IRP.

3) Narratives for each alternative future (the scenarios and sensitivities) should be included in the public document and not force the reader to scour the redacted information in their IRPs to piece together how the various scenarios and sensitivities were developed.

4) Sufficient detail about forecasting methods (including equations, methods, and data sources) must be included in the public version to the extent possible.

5) Details about how DSM (both energy efficiency and demand response) was developed should be contained in the public version. Discussion of whether DSM – particularly demand response –should be treated as a load adjustment or as a resource should be explicitly discussed. The utility should provide commentary on how DSM is treated in comparison to electric generation options. This would include how DSM was "bundled" and integrated into the planning process. This should be well written and provide sufficient detail for the reader to be able to understand the utility's process.

6) Considering SEA 412's statutory integration of DSM with the IRP process and the potential for DSM to serve as a compliance measure for future environmental regulations, future IRPs will need to include a more robust discussion of the development of cost-effective DSM and greater attention to Evaluation Measurement & Verification (EM&V) analysis of DSM/EE programs. As stated previously, increased efforts to more fully integrate DSM into the resource planning process in a manner that is as comparable as possible to other resources will be essential.

7) Graphics used in the public version are essential to helping the reader understand important concepts and have improved since the previous IRPs but more work remains to be done. Utilities should not redact critical information if at all possible. Recognizing there are proprietary concerns for some data, the utility should make every effort to use public data or a composite of public and proprietary data as a substitute for the sole use of proprietary data.

D. DIRECTOR'S COMMENTS REGARDING THE UTILITIES' IRPs

1. IPL's INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

This Final Director's Report reflects the following issues and emphasizes those that the Director regards as the most important concerns. This Report does not address all the questions and concerns raised by the Director or stakeholders in the Draft Director's Report. The issues are:

- Risk and Uncertainty Analysis
    - Natural Gas Prices
    - Environmental Costs Such as those Related to Carbon Dioxide Prices
- Load Forecasting

- Demand Side Management (DSM)
- Distributed and Customer-Owned Generation
- Regional Considerations
- Stakeholder Process

Risk and Uncertainty Analysis

The Director expressed concerns that the risk and uncertainty analysis performed by IPL was too constrained, that the relationship between steps was unclear, and that consideration of some uncertainties was problematic.

IPL'S Comments on Risk Analysis and Scenario Development On page 2 of IPL's response to the Director's Draft Report, regarding the selection of scenarios being "arbitrary", IPL stated:: "*The creation of the five resource plans is not arbitrary, but based on results and knowledge from a number of analyses…IPL identified five different resource plans to determine the impact of Petersburg 1 and 2 retiring early, symbolic of the Low Gas and High Environmental results… Thus, when determining the creation of the plans for further analysis, IPL also incorporated additional information, including the size and age of the units and the results gathered from the analysis conducted for the National Pollutant Discharge Elimination System ("NPDES") NPDES, compliance filing (Cause No. 44540)… The results identified retrofitting all four Petersburg units as the reasonable least cost plan and is consistent with the IRP results… Due to these results, IPL limited the retirements when creating the scenario resources plans to Petersburg Units 1 & 2 as a way of creating plans that could be more competitive in multiple scenarios. These resource plans were shown to be economically less favorable compared to IPL's base resource plan. A resource plan that further adds the retirement of Petersburg Unit 4 would be even less economically competitive. Additionally, the retirement of Petersburg Units 1, 2, and 4 would fail to accomplish IPL's goal of a low-cost diversified portfolio, as the plan would create a portfolio that is predominantly natural gas fired generation.*

More broadly, IPL includes multiple planning inputs into its scenario resource plan development and modeling and believe this process and interpretation provides better insight from a resource-planning perspective. IPL will work to be more transparent with this step in the process in its next IRP." IPL's response to the Director's Draft Report, page 3.

<u>Director's Response</u> IPL identified three drivers that were viewed to have the largest impact on future plans, along with having a great deal of uncertainty linked to them: environmental regulation, natural gas prices, and load variation.

IPL considered four environmental *landscapes* (scenarios) around costs and timing of effective dates for proposed CO_2 regulation: EPA Shadow Price (Base), ICF Mass Cap (Environmental), Waxman-Markey (High Environmental) and No CO_2 (Low Environmental).

IPL considered five fuel forecasts of NG prices: Base Gas Prices, High Gas Prices Landscape, Low Gas Prices Landscape, Environmental Prices Landscape and Mass Cap Prices Landscape.

IPL considered three demand and energy forecasts for load sensitivity: Base Load Forecast, High Load Forecast and Low Load Forecast.

Derived from the three key drivers, IPL created eight scenarios to screen the capacity expansion resources. The eight scenarios are as follow:

1. Base – Ventyx Base Gas/Market Prices, EPA Shadow carbon price starting 2020 and Base Load Forecast;
2. High Load – Ventyx Base Gas/Market Prices, EPA Shadow carbon price starting 2020 and High Load Forecast;
3. Low Load – Ventyx Base Gas/Market Prices, EPA Shadow carbon price starting 2020 and Low Load Forecast;
4. High Gas – Ventyx High Gas/Market Prices, EPA Shadow carbon price starting 2020 and Base Load Forecast;
5. Low Gas – Ventyx Low Gas/Market Prices, EPA Shadow carbon price starting 2020 and Base Load Forecast;
6. High Environmental – Ventyx Environmental Gas/Market Prices, Waxman-Markey proxy Ventyx Fall 2013 carbon price starting 2025 and Base Load Forecast;
7. Environmental – Ventyx Mass Cap Gas/Market Prices, Mass Cap ICF carbon price starting 2020 and Base Load Forecast;
8. Low Environmental – Ventyx Base Gas/Market Prices, no carbon policy and Base Load Forecast.

Resource options included in capacity expansion modeling were NGCT, NGCC, Nuclear, Photovoltaic and Wind turbine. Additionally, the model was used to determine if the early retirement of the four units at

Petersburg was economic in each scenario. Each one of the eight scenarios produced one capacity expansion plan.

Based on the results of the capacity expansion modeling, five plans were created to be tested for future landscapes (six of the eight future landscapes) in order to evaluate a range of resource options and combinations of resources. Under each future landscape, the first and second least cost plans among the five were identified.

The Director has a number of concerns that were not adequately addressed by IPL in their response comments to the Draft IRP report. For example, a significant remaining issue is the relationship between the resource plans that resulted from each of the eight initial scenarios evaluated and the subsequent five resource plans that were further analyzed.

Also the inclusion of carbon prices in the first five of the eight initial scenarios is problematic and raises questions about the interpretation and usefulness of the results. This is discussed more later in this section.

Optimization of the first eight scenarios showed that it might be economic to retire Petersburg units 1, 2, and 4 under the Low Gas scenario or retire Petersburg unit 1 in 2024 in the High Environmental scenario. Most of the other scenarios show no capacity is retired or built until 2030 or later. IPL then identified five different resource plans to determine the impact of retiring early Petersburg Units 1 & 2. IPL said this is symbolic of the low Gas and High Environmental results. The five resource plans developed by IPL outside of the modeling optimization process were then tested using six of the eight scenarios used in the initial optimization process.

While IPL's identification of key drivers they deemed most likely to affect their long-term resources was very credible and well articulated, The Director is concerned that the five resource plans developed by IPL for further analysis have little apparent relationship to any of the eight optimized resource plans. Plans 1 and 2 lock in IPL's existing capacity while Plans 3 – 5 assume Petersburg units 1 and 2 are retired in 2024. Why were both Petersburg units 1 and 2 forced to retire in the same year, a result strikingly different from the earlier optimization?

In IPL's comment about the five different resource plans to determine the impact of Petersburg 1 and 2 retiring early, use of the term "symbolic" of the Low Gas and High Environmental results indicate that the results were not objectively derived by the generation expansion planning model. The Director's concern was heightened by the following comment suggesting that IPL predetermined the outcome: "*Due to these results, IPL limited the retirements when creating the scenario resources plans to Petersburg Units 1 & 2 as a way of creating plans that could be more competitive in multiple scenarios…*" page 3 of IPL's Response to the Director's Draft Report. Given these circumstances, it is reasonable for the Director to conclude that IPL used what might be called professional judgment to develop the five resource plans. Effective and appropriate use of such judgment is critical for effective long-term resource planning but the basis for its use and how it was used must be clearly articulated. Such was not the case here.

Notwithstanding IPL's rationale and citations to work that were not included in the IRP, the Director still does not understand the relationship between the five resource plans created by IPL for further analysis and the initial resource plans developed for each of the eight scenarios. For example, one scenario had Petersburg 1, 2, and 4 retiring in 2020 and another scenario had Petersburg 1 retiring in 2024. But three of the five plans created by IPL for additional analysis locked in the retirement of Petersburg 1 and 2 in the year 2024 and the other two plans created by IPL had no retirements. The creation of the plans for further analysis appears to be arbitrary which creates serious doubt about the conclusions IPL derives as to the preferred resource plan.

IPL's Response Regarding Natural Gas Prices **"***IPL recognizes that a detailed description on the natural gas prices is not provided until Confidential Attachment 5.1. IPL will provide this information more transparently in future IRPs along with more intuitive scenario names and narratives."* page 2 of IPL's Response to the Draft Director's Report.

Director's Response The Director appreciates IPL's recognition that the public IRP version should have more discussion of the critical drivers such as natural gas prices and greater transparency within the public version of the IRP (e.g., populating graphs with public domain or blended public domain and proprietary data) would be beneficial for this information.

IPL's Response Regarding Environmental Costs Such as those Related to Carbon Dioxide Prices
"*IPL modeled 4 CO_2 futures, as identified on page 51 of the IRP, to robustly analyze possibilities including no CO_2 costs, the EPA shadow price landscape as a fixed cost, and an ICF Mass Cap landscape and the more extreme proposed Waxman-Markey legislation as variable costs… The first CO_2 landscape based on the Clean Power Plan ("CPP") which IPL named the EPA Shadow Price landscape, reflects fixed compliance costs based on a $/kW which do not directly affect unit dispatch but do affect the PVRR analysis. The second CPP CO_2 landscape, which IPL named ICF Mass Cap, assumes a CO_2 tax applied as a variable cost to existing generation which directly affects unit dispatch. The variable costs modeled as $/MWh were correlated to market and gas prices. The use of a no CO_2 landscape and a CO_2 landscape representative of the Waxman-Markey legislation provide an effective bound around the potential CO_2 futures."* page 4 of IPL's Response to the Draft Director's Report.

Synapse Comments On page 5, **"***In Section* 3 *the Company's carbon price is not applied properly in most scenarios* [*and*] *as a result, the Company's analysis biases the results towards continued operation and investment in its coal fleet. Future Environmental spending is not all included in IPL's modeling. The Company provided a range of estimates for compliance with upcoming environmental regulations such as Coal Combustion Residuals (CCR), Effluent Limitation Guidelines (ELG). Cooling Water Intake (Section* 316 *(b) of the Clean Water Act, Cross-State Air Pollution Rule (CSAPR), and National Ambient Air Quality Standards (NAAQS). However, it appears that most or all of these future costs were not included in the IRP modeling."*

On pages 5 and 6, Synapse states, *"It also appears that the Company's eight modeling scenarios failed to account for all of the potential costs associated with these environmental compliance obligations… After the capacity expansion modeling, IPL evaluated five portfolios (Plan* 1 -5) *under multiple scenarios of natural gas and carbon prices. This analysis was limited to simply testing five portfolios against different commodity price variations ... the IRP lost the opportunity to review how different explicit variable changes impact the choices of portfolio.. By only changing gas and carbon costs, individually, it is impossible to see the results with combinations of risks (e.g., High Gas / High Environmental).*" On page 9, Synapse explains that the Base, Low Gas, and High Gas scenarios only apply carbon costs as a fixed cost rather than as a variable cost. As a result, dispatch of coal units aren't affected. This favors coal-fired units in the dispatch. (Synapse Energy Economics, Inc. on Behalf of Sierra Club.)

Director's Response to IPL The Director agrees with Synapse that IPL's construction of scenarios and sensitivities seems intended to favor its coal fleet. The Director wonders if the resource mix would have been the same if the drivers for the scenarios and sensitivities were significantly (but plausibly) different? The Director commends IPL for inclusion of a range of CO_2 costs in their analysis. However, and notwithstanding IPL's use of the Waxman-Markey estimates, we believe the range of CO_2 costs was too constrained especially if other environmental risks were integrated into the analysis. The Director agrees with IPL that, as more information is known, the treatment of CO_2 and other environmental costs will be much clearer for the next IRP.

Additionally, the Director is concerned about the validity of modeling a fixed carbon price used as the shadow price for CO_2 but only applied after the fact so that it is modeled as a fixed cost in most of the scenarios for a couple of reasons. First, it seems more likely CO_2 would be treated as a variable cost which would affect the dispatch. Secondly, making meaningful comparisons between scenarios that treat CO_2 as a fixed cost compared to a scenario that treats CO_2 as a variable cost would be difficult. That is, it's not clear what the purpose of the different treatments was intending to accomplish.

<u>IPL’S Response to Load Forecasting</u> “*IPL concurs that the application of the State Utility Forecasting Group derived (IPL-specific) load range to IPL's Base Forecast was not specifically intended for IRP analysis. However, IPL viewed this range as a reasonable proxy to represent a multitude of potential differences from our base forecast, including but not limited to DSM adoption rates, economic growth, and Distributed Generation ("DG") growth. IPL recognizes that this is an area for potential improvement for future IRP iterations and will look to improve upon this methodology.”* page 4 of IPL’s Response to the Draft Director’s Report.

<u>Director’s Response</u> The Director is pleased with IPL’s recognition that their load forecasting can be enhanced. Because the load forecast is integral to the development of scenarios and sensitivities, the Director would like IPL to discuss the changes made in the various forecasts, discuss the rationale for these differences/changes, and how they would contribute to the different scenarios developed in a manner that is logically consistent.

With regard to elasticity, the Director agrees that price elasticity was incorporated into IPL’s10 year base case forecast but it would be helpful for a more detailed discussion of the methodology so that we understand how it affects the development of the various scenarios and sensitivities (including DSM). It isn’t entirely clear, for example, how IPL’s specific elasticity may have been integrated into the adjusted SUFG high and low load forecast on an internally consistent basis. Additionally, IPL should discuss where they get the estimates (e.g., a source like Global Insight or does IPL develop estimates in-house?). Either is fine but it would help if elasticity estimates were more transparent.

More generally, the Director is concerned that the load forecast methodology used by IPL might seriously understate the extent of uncertainty associated with load. There are several different ways to develop a range of load forecasts and it is not obvious that one is necessarily better than another. The concern is that most utilities understate load forecast uncertainty and this is not adequately recognized by the utility and other stakeholders. For example, if an econometric formulation is used, the standard deviation of the error term in the model formulation can be used to derive the low and high forecasts (for instance, they can be two standard deviations from the mean). In doing this, a utility does not need alternate economic projections but this tends to understate the uncertainty because it treats drivers as having no uncertainty. It is also appropriate to use alternate economic assumptions. But only having alternate projections for some economic drivers means some other drivers (like population) don’t change between the high, base, and low forecasts. This also tends to understate the uncertainty.

As described above, IPL’s approach to developing high and low load forecasts make it difficult to judge how well IPL captured the extent of load forecast uncertainty. The SUFG bands are driven by changes in economic growth assumptions but IPL states that they interpret them as representing uncertainties from economics, DSM program impacts, and technological and behavioral changes. IPL's interpretation of SUFG's bands is incorrect. SUFG's bands are based on changes to real personal income, non-manufacturing employment, and gross state product only. DSM, for example, is the same in all three SUFG load forecasts. It would be better for IPL to develop forecast bands in-house.

It is the Director's perspective that it is critical to sound integrated resource planning for the load forecast to attempt to reflect, to the extent reasonably possible, the range of uncertainty inherent in any long-term forecast of load. Failure to do this can mean the uncertainty and risk analysis conducted at the end of the planning process is less useful than might otherwise have been the case.

IPL'S Response to DSM In the DSM Modeling Appendix on page 20 of IPL's response to the Draft Director's Report, *IPL agrees with the Commission staff that DSM should be considered a resource, and as such should be evaluated and selected consistently, comparably, and objectively versus supply side resources in order to provide a reliable, low cost, low risk portfolio to all its customers*. IPL discussed their DSM Screening Process and Evaluation (beginning on page 107 of their IRP*): Screening of demand-side measures is a multi-step process. Measures are first qualitatively screened and then logically grouped into prospective programs. These programs are then systematically evaluated with the aforementioned cost effectiveness tests IPL calculates future avoided costs and compares them to projected savings*.

By way of background, on page 111 of IPL's IRP, IPL discusses the tests used to derive its prospective DSM programs. First, IPL will look at the RIM test. For programs that don't pass the RIM Test, IPL will include programs that pass the TRC and UCT tests. Programs that fail the TRC test may still be included if they are deemed useful for market continuity, market transformation, public education, synergy with other programs, or other reasons. Finally, IPL uses the PCT. *In Cause 44497, IPL also introduced the concept of a hybrid test which was identified as the Customer Balance Test (CBT). This is to assess the degree of subsidization but not as a pass / fail test. Programs that are found to be cost-effective from the UCT and TRC test perspective can be further ranked by the CBT ratio. The CBT is not used as a pass /fail test but serves as an indicator that programs that did pass the TRC or UCT tests…should be further examined to determine whether other factors warranted their inclusion in the DSM plan.* pages 111 -112 of IPL's IRP.

Director's Comments The Director recognizes that IPL made a commitment to expanded reliance on DSM (e.g., page 97 and comments made by IPL including by Ms. Kelly Huntington during the 2015 Summer Reliability Forum). IPL states they made an effort to treat DSM in a comparable manner to traditional generating resources. However, it isn't clear how IPL integrates DSM into their resource plans.

The Director recognizes the difficulty of integrating DSM into the planning process and treating DSM similarly to traditional generating resources but separate treatment of DSM from other resources gives, at a minimum, the appearance of being separate and unequal. The doubt as to whether demand-side resources are being treated comparably to supply-side resources is all the stronger when the level of DSM resources, included in the various resource plans developed from different scenarios, is the same. It is not definitive but an unchanging level of DSM, under a range of different scenarios, is sufficient cause to doubt the reality of comparable treatment.

For example, on page 47 Figure 4.3 and despite Figure 4B.5 on page 121 showing substantially greater DSM potential, DR is held constant at 63 MW through 2025. DSM is often not included in IPL's discussion of resources in the Public Version or the Confidential Version which also raises concern that DSM was not truly integrated with other resources in the planning model outputs. If the Director misunderstands IPL's treatment of DSM, it would be helpful to the Director to better understand how IPL constructed the DSM packages and, then, screened them. The Director also has concern about the avoided cost calculations since they don't appear to change significantly even when IPL is considering other resources.

The Director is also concerned given the difficulty required to try to understand how IPL analyzed DSM. The discussion of DSM is disjointed because related material is presented across a range of sections of the primary IRP document and multiple appendices. This might be necessary but imposes a heavy burden on IPL to clearly explain and document all facets of their DSM analysis and this was not done. For example, Section 4B Demand-Side Management does not explain what level of DSM has been included in the planning process. Only by looking at Figure 4D.6 on page 145 in the Load Forecast section can one know the DSM assumptions applied to the load forecast.

IPL'S Response to Distributed and Customer-Owned Generation In response to the Director's comments that customer-owned and distributed generation appeared to be "baked into" the IRP analysis, IPL responded: "*While increased Distributed Generation was not explicitly modeled…, IPL did model a Low load scenario, which as discussed in the IRP could represent a multitude of differences from the base case, including but not limited to increased DSM participation, slow economic growth and increased Distributed Generation. While IPL recognizes that some customers may wish to install distributed generation for reasons other than financial economics, IPL's experience over the past several years shows very little DG growth other than the growth emerging from our Rate REP. IPL will continue to monitor DG growth and plan to model high DG penetration in future IRPs as a sensitivity.*" page 4 of IPL's Response to the Draft Director's Report.

Director's Response The Director recognizes that forecasting distributed and customer-owned generation is difficult and may be a worthwhile topic for the Contemporary Issues forum. While subtracting this resource from load like "DSM" or "slow economic growth" has some intuitive appeal, customer-owned and distributed generation is likely to have a greater demand component than DSM and slow economic growth. The Director agrees with IPL that continued monitoring of changes in this resource is appropriate (Smart Grid and AMI should provide a wealth of data over time), we hope we can have a more extensive discussion of Distributed Generation (DG) related issues as they affect long-term resource planning and more explicit modeling that incorporates the experience of DG adoption in Indiana and other states.

IPL's Response to Regional Consideration Initial (January 30, 2015) Comments from the Citizens Action Coalition, Earthjustice, Indiana DG, and Sierra Club state: *"The most recent revisions to the IRP rule were intended to recognize the increasing regional interconnectedness of Indiana utilities, and to facilitate a collaborative process for evaluation of the potential ramification of a range of risk and uncertainties facing the electric sector, such as increasingly stringent environmental regulations (including region of greenhouse gas emissions) and increasingly low-cost and available demand-side renewable resources... [A]s detailed, the three utilities* [NIPSCO, IPL, and Vectren] each *undervalue, and in some cases disregard, clean, low-cost energy and resources by failing to analyze demand-side and supply-side resource alternatives on a consistent and comparable basis."* page 1 of Initial (January 30, 2015) Comments from the Citizens Action Coalition, Earthjustice, Indiana DG, and Sierra Club.

The Director's Response The Director agrees with CAC, Earthjustice, Indiana DG, and Sierra Club that the IRPs should give due consideration of regional resources and, depending on the final disposition of any rule, the potential for regional environmental compliance. The Director has confidence that utilities will incorporate the information about the ramifications of environmental regulations as more information is available.

IPL's Response to the Stakeholder Process The Director was gratified by comments made by IPL's President and CEO Kelly Huntington during the 2015 Summer Reliability Forum that the stakeholder process provided valuable insights and committed to making on-going improvements to enhance the process. Ms. Huntington attended all of the Stakeholder meetings and made her subject matter experts available to stakeholders throughout the process which contributed to the perception that IPL does, indeed, consider the IRP stakeholder process to be important. IPL credited the public participation process as influencing their construction of scenarios and sensitivities (e.g., page 50 of IPL's IRP) and identified increasingly stringent environmental regulations, natural gas prices, and load variation as the key risk factors.

In questions from Consumer Counselor Stippler, Ms. Huntington agreed stakeholder input in the construction of the base case as well as alternative futures as described by scenarios and their attendant sensitivities was important to ensure a meaningful stakeholder process. Also to IPL's credit, they made a concerted effort to encourage participation by larger customers. Ms. Huntington and the IPL staff also acknowledged the evolutionary nature of the IRP process. The Director appreciates Ms. Huntington's support for a meaningful stakeholder process.

It would be helpful for all utilities to include important information, in some form, in the public version of the IRP Report rather than referencing confidential information. The usefulness of some of the graphics used during the Stakeholder meetings was compromised because of confidentiality concerns. Of greater concern was that some of the IRP analysis was predicated on other work (such as another matter before the Commission). It would have been very helpful to relate that information in the IRP filing and might have mitigated some of the Director's concerns about the robustness of IPL's risk analysis. To this end, the Director appreciates IPL's willingness to provide more discussion of critical factors and to be more transparent.

2. NIPSCO'S INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

This Final Director's Report reflects the following issues and emphasizes those that the Director regards as the most important concerns. This does not address all the questions and concerns raised by the Director or stakeholders in the Draft Director's Report on the 2014 IRPs. The issues are:

- Risk Analysis
- Load Forecasting
- Demand Side Management (DSM) Consideration
- Distributed and Customer-Owned Generation
- Stakeholder Process

<u>Risk and Uncertainty Analysis</u>

NIPSCO's risk and uncertainty analysis is too constrained and has too much information that was buried in appendices with little insight provided as to how the limited analysis was used by NIPSCO or informed the analysis.

NIPSCO uses the Strategist expansion planning module PROVIEW from Ventyx. The model simulates real world operation of NIPSCO's generation, transmission, and distribution system. The simulation has the capability to determine the cost and reliability effects of various resource plans. All feasible plans that satisfy the constraints within Strategist are ranked based on the Net Present Value of Revenue Requirements (NPVRR). The long-term resource plan that has the lowest NPVRR is selected as the preferred case.

To derive the best case, NIPSCO used market value to initially screen the supply and demand-side resources to limit the total number of options that can be examined at one time and within a single analysis. Each option was valued using a discounted cash flow. Only options with a positive discounted cash flow and a benefit/cost ratio of greater than 1 passed the initial screen. Any resource combination that passed the screen was eligible to be included in the resource plan development.

NIPSCO then used PROVIEW to examine the following:

1. **Gas Plan**: This included self-build supply-side peaking and intermediate options only;
2. **DSM/Gas Plan**: Gas Plan mixed with DSM options excluding the industrial direct load control (DLC);
3. **DSM/Gas/DLC Plan**: The Gas Plan mixed with all DSM options including industrial DLC:
4. **DSM/Non Gas Plan**: Coal and nuclear mixed with DSM options;
5. **DSM/Gas/Renewable Plan**: Renewable resources mixed with DSM options;
6. **DSM/Renewable Plan**: Renewable resources mixed with DSM options;
7. **Early Retirements Plan**: Early retirements of Bailly 7 and 8 were included in the DSM/Gas Plan.

These plans were evaluated under the same set of assumptions identified as the SLOW ECONOMIC IMPROVEMENT SCENARIO, considered NIPSCO's base case assumptions. The DSM/Gas/DLC Plan was the least cost expansion plan among the seven alternatives mentioned above. DSM/Gas was the second lowest cost option. However, since the potential to increase industrial Direct Load Control, characterized as unlimited curtailments and short notice interruptions was unknown when filing the Plan, the DSM/Gas Plan was designated as the base case. The resource expansion plan of the base case called for a new Combined Cycle Gas Turbine in 2023 and another CCGT in 2035.

NIPSCO developed another scenario named "Aggressive Environmental Regulations" which was treated as sensitivities to the Gas Plan, the DSM/Gas Plan, and the DSM/Gas/Renewable Plan. The Aggressive Environmental plan included increased environmental regulation compliance costs, higher natural gas prices, and increased electric prices. It also included a 5% Renewable Portfolio Standard (RPS) by 2020.

NIPSCO opted for a deterministic approach for sensitivity analysis – using single point estimates: expected, best, and worst for the input variables. This deterministic approach was extended to intra-variable correlations. Tested sensitivities included: high and low load growth, high construction cost escalation, high and low commodity market conditions, and aggressive regulation.

NIPSCO's Comments Regarding Risk Analysis *"The 2014 IRP scenarios demonstrate that NIPSCO has comprehensively examined a range of plausible future states of the world and is recommending a prudent path forward based on our analysis of available data….NIPSCO conducted many sensitivities and scenarios and highlighted the items defined in the IRP report. Under every 'stress test,' the plans called for a CCGT to be built when a coal unit is retired. This is not an issue of 'probabilistic' versus 'deterministic' with scenarios and sensitivities. The simple fact is that the resource additions are driven by the retirement of existing generation assets. No amount of added analysis, or stochastic analysis, is going to change the fact that when large generation assets retire, they must be replaced with equivalent high to mid load factor resources. Relatedly, the Draft Report states that NIPSCO (i) did not consistently evaluate retirements of its existing coal-fired generating units on a level playing field with other, potentially less expensive, resources, (ii) failed to model the possibility of retiring each of its units, (iii) placed an arbitrary constraint on its modeling of retirement alternatives, and (iv) did not model the possibility of retiring any of the Schahfer facility during the planning period. In response to these items in the Draft Report, NIPSCO would point out that it assumed out-of-service dates for coal-fired units based on average life spans of sixty years. While the service life of an individual unit can be longer or shorter, as a unit approaches retirement, additional analysis will be conducted to better estimate the projected out-of-service date. Simply stated, the model did not select any units for retirement. NIPSCO further evaluated the impact of early retirement on its oldest units, Unit 7, Unit 8 and Unit 12 which were placed into service in 1963, 1968 and 1974, respectively. Early retirements did not provide any economic benefits."* page 3 of NIPSCO's Response to the Draft Director's Report.

Director's Response to NIPSCO At the outset and in contrast to NIPSCO's representation that "*NIPSCO has comprehensively examined a range of plausible future states of the world,"* NIPSCO had just one "alternative" scenario to its base case. The Director and Commission staff, in conversation with NIPSCO staff during the formulation of their IRP, expressed the concern that the lack of alternative scenarios and associated sensitivities is insufficient to provide a reasonable or credible assessment of the risks that NIPSCO has articulated. The Director reiterates the concern here. No narrative was included as to how the "alternative" Scenario case affected NIPSCO's IRP analysis.

In comments on the Draft IRP report, NIPSCO states that an optimal plan was developed as a result of the optimization based on the assumptions in the Aggressive Environmental scenario and that the information is presented in Confidential Appendix J on page 7,346. NIPSCO goes on to say the optimal plan under this scenario is plan 1; the first 1,824 plans are reported on pages 7,346 through 7,573 in the Proview Least Cost Optimization System-Planning Period Plan Comparison report (See request 1-1 in NIPSCO's Comments).

In Request 1-2 NIPSCO states the sensitivities conducted on the Aggressive Environmental Scenario are summarized at the bottom of page 634 of Appendix E. It states that high load growth, low load growth, Synapse Carbon Forecast, and solar resource additions sensitivities were included.

The Director acknowledges that NIPSCO appears to have performed a broader range of uncertainty analysis than discussed in the main IRP report. However, it remains the case that the reader of the IRP has no knowledge or understanding of what the results of the Aggressive Environmental Regulations scenario analysis were or of how the analysis affected (or not) NIPSCO's thinking because NIPSCO failed to discuss these matters in the body of the IRP report. A reader should not have to wade through thousands of pages of computer results to find the appropriate files. After all, how is it possible that a company creates two, and only two, scenarios and says virtually nothing about the results for one scenario and how it affected NIPSCO's understanding of its risks and uncertainties? Without a far more complete discussion of NIPSCO's risk and uncertainty analysis it is impossible to say whether the recommended resource plan is reasonable.

Preferably, NIPSCO would have first developed a few more scenarios based on distinct possible futures, for example, a scenario which assumes faster economic growth improvement with higher electricity demand. Then an optimal resource plan would have been developed for each scenario, and each of these plans should have been subjected to stress testing.

The limited number of scenarios made NIPSCO's practice of sequential treatment of sensitivities confusing and concerning (i.e., treating each sensitivity as being separate or layering). Separate scenarios would have made it possible to better discern the individual and, ultimately, the interrelated affects of the various sensitivities (e.g., the separate treatment of changes in various environmental costs, changes in fuel costs, changes in load forecasts, changes in the cost-effectiveness of DSM, the potential for expanded development of combined heat and power by NIPSCO's larger customers, etc.) on the various scenarios. The Director expressed these concerns in discussions with NIPSCO staff during the formation of the IRP that the base case and a single alternative case was insufficient. In sum, the relatively narrow risks and the extremely limited discussion of what was done in NIPSCO's Plan fell well short of the "*outer bounds of probability / plausibility"* that NIPSCO was concerned with.

From the information NIPSCO provided in NIPSCO's IRP and highlighted in their response to the Draft IRP Report, some analysis was done for other stakeholders. NIPSCO should be commended for this level of stakeholder involvement. However, the Director – and perhaps other stakeholders – were not made aware of the results of that analysis, whether the stakeholders concurred with the analysis, and how, if at all, the stakeholder analysis affected the long-term resource planning outcomes for NIPSCO's "alternative" scenario or NIPSCO's IRP. Because such analysis may inform the stakeholder process, the Director encourages NIPSCO (and other utilities) to provide the information to all stakeholders. At a minimum, there should have been a discussion in NIPSCO's IRP report of this additional analysis and how it informed other aspects of the IRP prepared by NIPSCO.

The Director assumes NIPSCO's statement on page 3 of NIPSCO's response to the Draft Director's Report, "*No amount of added analysis, or stochastic analysis, is going to change the fact that when large generation assets retire, they must be replaced with equivalent high to mid load factor resources*" does not preclude consideration of a combination of other resources (e.g., purchased power, different types generating units, customer-owned resources, DSM, etc.) that, taken as a whole, would fill the void resulting from the retirement of a large unit and make the system more reliable, resilient, and economical. Limited scenario analysis combined with very limited discussion of NIPSCO's risk and uncertainty analysis makes it difficult for staff to concur with NIPSCO's perspective.

Load Forecasting

The Director believes more description of the load forecasting process would be beneficial to better understand how the load forecast is prepared including the high and low forecasts given the importance of load as a critical source of uncertainty.

NIPSCO (page 18 of NIPSCO's response to the Draft Director's Report) states that the 2014 energy and demand forecasts uses an econometric approach to forecast long term energy sales and peak hour demand. The forecast employs data representing service area demographics and economic data, saturation and efficiency information, electric energy sales by class, price of energy and average monthly and peak hour weather. Residential usage is related to end uses and efficiencies, and real per capita income. Commercial activity is captured with actual county retail sales. Prices for typical electric bills are used in both the residential and commercial econometric models to measure customer behavior in reaction to changing prices.

For the residential customer forecasts, the drivers appear to be appropriate but additional discussion as to how the variables such as housing stock is integrated into the long-term forecasts would be beneficial.

The Commercial energy usage model is a function of the number of commercial customers, county retail sales, energy price, and cooling degree days (but apparently not heating degree days).

For industrial customers, the Director appreciates that forecasting industrial usage and demand is difficult, especially beyond a couple of years. The Director also appreciates the sensitivity that industrial customers have to sharing significant business information and NIPSCO's recognition that 1% of their customers constitute more than 50% of their load. However, informed judgment is not an ideal way to forecast demand and energy sales for such an important part of the NIPSCO system. As NIPSCO noted, these customers can cause very large and rapid swings in demand. Even NIPSCO's reliance on judgment doesn't account for the constant demand for this class of customers that is reflected in NIPSCO's IRP.

High and low load growth forecasts were constructed from the base forecast. High and low load growth energy for residential and commercial classes were calculated with the underlying model predicted values, along with the statistically estimated 95 percent confidence band around those values. The high growth forecast reflects industrial customer expansions currently being developed within NIPSCO's service territory. It also reflects additional industrial demand based on the load observed in 2013.

NIPSCO's Comments Regarding Load Forecasting On pages 17-18 of NIPSCO's IRP, NIPSCO states: "*…Industrial customers, primarily steel and oil refining, account for less than one percent of NIPSCO's total customers. These customers, however, make up more than 50% of NIPSCO's total energy sales…While operations consume large amounts of energy, their consumption can vary widely on short notice. These industries follow economic cycles and are tied to the global economy. As such, NIPSCO's planning assumptions are heavily dependent on its ability to accurately forecast future economic activity…There are several key characteristics underlying NIPSCO's industrial forecast.*

- *Volatility of the industrial load…If industrial users use less or more than predicted, or operate with greater or more frequent load swings, the forecast may not be representative of future actual events.*
- *If one large industrial customer severely downsizes or shutters its operations, this may result in cost shifts…*
- *Steel production levels vary. In the latest recession, from 2007-2010, steel industry energy consumption dropped more than 30 percent.*
- *The future of carbon or greenhouse gas ("GHG") regulation is uncertain."*

NIPSCO states Major Industrial Forecast is based on industrial forecasts for each of its major industrial customers. According to NIPSCO, this information, *"integrates the actual economic and business projection of the customer*." Page 19 of NIPSCO's IRP. NIPSCO describes its forecast methodology: "*The Industrial Energy Forecast Model forecasts the expected level of industrial energy sales…Accordingly, the* *industrial energy forecast model contains individual forecasts of major industrial account customers. To obtain information specifically available to the creation of the industrial sales forecast, NIPSCO makes contact with each of its Major Industrial account customers. The goals, plans and concerns outlined in these on-on-one discussions form the basis of the forecast… The industrial sales forecast model also integrates a sales forecast for the remaining industrial accounts (identified as Other Industrial). The Other Industrial forecast includes analysis of historic usage patterns, on-going discussions with industrial customers, and industry related intelligence."* page 19 of NIPSCO's IRP.

Director's Comments Regarding Load Forecasting The Director has two primary concerns about the load forecast and the associated discussion presented in the IRP. First, more detail is necessary to properly understand how NIPSCO prepared the load forecast. Second, the Director believes the methodology used in developing the load forecast understates the uncertainty surrounding future load.

NIPSCO recognized the substantial financial risk to the company and its other customers (e.g., the potential for cost shifting to other customers) associated with serving industrial customers. However, the explanation of the forecasting process is not clear and raises credibility concerns. Table 4-3 on page 24 of NIPSCO's IRP depicts energy sales to industrial customers as being constant from 2019-2035 despite the historical information that industrial load varied from as low as 7,691 GWhs in 2009 [during the recession] to as high as 10,006 GWhs in 2014. Given these significant risk factors, and despite NIPSCO's description of their forecasting process for industrial customers the Director is concerned the load forecasting effort isn't commensurate with the risks that NIPSCO identified.

Despite NIPSCO's explanation, the Director does not understand the discussion of how NIPSCO's large industrial and "Other" industrial/large commercial customer load is forecasted. The Director understands the large industrial customers forecasts are based on conversations with the customers yet it isn't clear how these conversations are integrated into the load forecasts for these customers. The discussion of the Other C/I customer forecast seems to be a more traditional load forecast but it's not clear how all of the Other customers were forecast, especially taken with larger industrial customers and the resulting flat forecast. It would make it clearer if NIPSCO provided not only a detailed narrative but also the equations and coefficients in the public version of the IRP.

The confusion about forecast methodology is caused in part by descriptions in Appendix A that appear to contradict in part the description contained in the main body of NIPSCO's IRP report. According to page 1 of Appendix A, Major Industrial energy consumption is driven by forecast information directly provided by customers as well as historical trending and incorporates data from industry sources such as the Industrial

Production Index (Primary Metals) growth curve. But it appears that NIPSCO relied solely on information provided in meetings with these large customers.

Page 1 of Appendix A also says “Other” Industrial energy consumption is driven by historic industrial sales data as well as national and state production indexes and the Industrial Production Index (Primary Metals). Again, this appears to contradict to some degree what is stated in other parts of the IRP report.

NIPSCO’s comments on the Draft Director’s Report (Request 1-17 on page 23) emphasize the uncertainty over many variable cost inputs to their large customers’ manufacturing processes, so they argue it becomes very difficult for NIPSCO to forecast the long term customer volume and demand with any certainty beyond the first two years. Therefore there is, in NIPSCO’s opinion, no better way to forecast over a 20-year horizon than to assume the demand remains constant.

The lack of detail presented by NIPSCO makes it impossible for staff to evaluate the reasonableness of this decision. No information was presented to see how well various econometric specifications could be used to explain the historic data. Also, it is by no means obvious that forecasting explanatory variables is any more difficult for NIPSCO even with their large concentration of industrial load than for any other utility.

A transition from informed judgment to an econometric approach may be appropriate once they get past the first few years where information on customer plans is available.

The Director is concerned that the load forecast methodology used by NIPSCO might seriously understate the extent of uncertainty associated with load. There are several different ways to develop a range of load forecasts and it is not obvious that one is necessarily better than another. But it is the Director’s concern that most understate load forecast uncertainty and that this is not adequately recognized by the utility and other stakeholders. For example, if an econometric formulation is used, the standard deviation of the error term in the model formulation can be used to derive the low and high forecasts (for instance, they can be two standard deviations from the mean). In doing this, one does not need alternate economic projections. However, using this technique tends to understate the uncertainty because the drivers are treated as having no uncertainty. It is also appropriate to use alternate economic assumptions. Having only having alternate projections for some economic drivers means some other drivers (like population) don’t change between the high, base, and low forecasts. This also tends to understate the differences.

NIPSCO’s ad hoc approach to developing base, high, and low industrial load forecasts makes it difficult to judge how well NIPSCO captured the extent of load forecast uncertainty.

NIPSCO'S Demand Side Management (DSM) Consideration NIPSCO has 377 MW of demand response from large customers with at least 1 MW of demand. This is registered with the Midcontinent ISO. NIPSCO also has a program started in 2012 for cycling air conditioning units (pages 61-62 of NIPSCO's IRP). NIPSCO's enumeration of the individual DSM programs was helpful. Table 5-15 on page 53 shows "Projected Cumulative Savings (MWh)" due to DSM provided that "*no industrial customers would elect to opt out of the program provided for in SEA 340.*" page 52 of NIPSCO's IRP.

On page 4 of NIPSCO's response to the Draft Director's Report regarding Demand Response, NIPSCO states its intention "*to make efforts to increase this amount. At this point, NIPSCO will continue to evaluate the cost-effectiveness of increasing the amount of demand response from its industrial customers. Increasing this amount does impact all other firm customers through the payment of the demand credits afforded to those participating customers. NIPSCO would also note that the benefits of additional direct load control continues to be evaluated, and one of its customers is now participating in MISO's DRR program, pursuant to Rider 681.*" NIPSCO is commended for its engagement of Applied Energy Group to identify the DSM appropriate measures. NIPSCO states it "*conducted an initial screen of these various measures using the DSMore Model by assessing the benefits (or avoided costs) against the costs of the measure. As such, if the benefits of a measure did not outweigh the costs, the measure was dropped from consideration. As measures passed the initial screen, they were then aggregated by end use (heating, cooling, lighting) and then by sector (residential, commercial, and industrial). The various measures aggregated by end use sectors were then run through the industry standard tests to determine whether they would pass the initial screen of Total Resource Cost ("TRC") test and Utility Cost Test ("UCT") scores. Upon passing these tests, they were then run through the Ratepayer Impact Measure ("RIM") test, Societal test, and the Participant test and passed along as potential resource options to be modeled into the Strategist model.*

The integration process starts with further screening of resource options within the Strategist model. Both the supply-side and demand-side resources were screened on market value. Options that have a positive market value and a benefit-cost ratio greater than one. Next the optimal self-build plan using only aero derivative CTs, frame CTs and CCGT resources ("Gas Plan") is identified. Any supply side resources could have been used at this point to meet customer demand requirements. NIPSCO did not start with demand side resources since they are insufficient to meet customers' demand requirements.

Then DSM options are integrated to determine the optimal mix of DSM and gas resources ("DSM/Gas Plan") to meet customers' demand requirements. In fact, NIPSCO's market valuation of the DSM options was confirmed by their selection in the optimization. Then, keeping DSM resources in, supply side resources are switched to non-gas resource options to determine if these assets bring value to the NIPSCO system

("DSM/Non-Gas Plan"). This helps to identify the cost difference for various resource options, and allows us to look more closely at which specific resource options work better together to meet customers' demand requirements. Then, keeping DSM resources in, supply side resources are switched to renewable resources to determine if these assets bring value to the NIPSCO system ("DSM/Renewable Plan"). Then, keeping DSM and renewable resources in, supply side resources are switched to include gas resources to determine if these assets bring value to the NIPSCO system ("DSM/Gas/Renewable Plan"). *Finally the optimal plans are compared by looking at the NPVRR established in Strategist."* pages 4 and 5 of NIPSCO's response to the Draft Director's Report.

As Jim Stanley (CEO of NIPSCO) and other CEOs noted during the 2015 Summer Reliability Forum, the need for cost-effective DSM will be significantly greater if the Clean Power Plan is approved and the proposed compliance methods that include heavy reliance on energy efficiency are maintained.

Director's Response The constant amount of demand response or other DSM may be appropriate; especially if there are no plausible scenarios where NIPSCO would be adding or replacing existing resources and there is no regional market imperative to have more (or less) DSM. However, if these conditions don't exist as a result of a more comprehensive evaluation of potential risks, then DSM should be compared to other resource alternatives to the extent possible. Failure to discuss and present the Aggressive Environmental Regulations scenario results makes it difficult for the reader to determine just how comparable the treatment of DSM and supply-side resources was. Higher environmental regulations should increase the value of DSM but NIPSCO failed to present the necessary information.

From NIPSCO's limited discussion it was clear that they kept DSM separate from other resources and the analysis didn't result in any changes (higher or lower) to DSM. However, we were gratified by Jim Stanley's comments that there are plausible scenarios that would necessitate an evaluation of NIPSCO's DSM effort.

NIPSCO's Consideration of Customer-Owned Generation NIPSCO (page 62 of NIPSCO's IRP) discussed its Feed-In-Tariffs I and II to promote renewable resources. For NIPSCO large industrial customers, NIPSCO (page 19 of NIPSCO's IRP) *"assumes that most of NIPSCO's large customers with self-generation utilize this generation as a by-product of steam production needs. The generation is not predictable…"* In its response to the Director's Draft Report on page 6, NIPSCO correctly noted "*NIPSCO's customers served under Rider 676 (Back-up, Maintenance and Temporary Industrial Service) have more than 800 MWs of behind the fence generation. In addition, NIPSCO has customers that offer power pursuant to NIPSCO's cogeneration/alternative energy tariff (Rider 678 (Purchases from*

Cogeneration and Small Power Production Facilities)). The issues and concerns raised in this section of the Draft Report regarding Distributed Generation is addressed in the Appendix, Request 1-35 through 1-37." page 6 of NIPSCO's Response to the Draft Director's Report.

<u>Director's Response</u> The Director agrees that NIPSCO has a significant amount of generation participating in the Feed-In-Tariff and that customer self generation is not predictable for any specific customer, for the timing of having the CHP in-service, the characteristics of the CHP, or the amount of CHP. There was no forecast of future changes, however, (higher or lower); especially by NIPSCO's largest customers. Without a more comprehensive analysis of potential risks such as conditions that might prompt large customers to consider more (or less) Combined Heat and Power, it appears the analysis was insufficient. As Mr. Carl Chapman (Vectren's Chairman, President, and CEO) noted during the 2015 Summer Reliability Forum, customers may install their own generation even if the utilities do not believe it is cost-effective for the customer to undertake this investment.

<u>NIPSCO's Consideration of the Stakeholder Process</u> "*NIPSCO hosted two in- person and one web-based meeting for its collective stakeholder group. However, NIPSCO focused on and particularly appreciated the one-on-one meetings (a total of 18 meetings with different stakeholder groups were held during the development of the IRP) and discussions with stakeholders to drive the type of fruitful attention to detail that the individual stakeholders, with varying interests, desired as part of the IRP process*." page 6 of NIPSCO's Response to the Draft Director's Report.

<u>Director's Response</u> The Director commends Mr. Jim Stanley and NIPSCO's management for their active participation in both of the in-person meetings. Mr. Stanley agreed with Consumer Counselor David Stippler that he believed, that for meaningful participation, stakeholders should be involved in the formation of the base case as well as the construction of alternative scenarios and their sensitivities. In addition to the two in-person meetings, the Director commends NIPSCO for holding one-on-one meetings. However, the IRP did not specifically reflect the fruits of the discussions held with all stakeholders. For future IRPs, the Director hopes that NIPSCO will make a concerted effort to inform all stakeholders of the one-on-one discussions and how the associated analysis affected the IRP.

Moreover, NIPSCO, like the other Indiana utilities, made an effort to increase participation by larger customers. As with all aspects of the IRP process, the Director hopes that NIPSCO will give on-going consideration to proposals that may increase public participation, understanding, and make the process as meaningful as possible.

3. VECTREN'S INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

This Final Director's Report reflects the following issues and emphasizes those that the Director regards as the most important concerns. This does not address all the questions and concerns raised by the Director or stakeholders in the Draft Director's Report on the 2014 IRPs. The issues are:

- Risk Analysis
  - Customer-Owned Generation
- Load Forecasting
- Stakeholder Process

Risk and Uncertainty Analysis

During the 2015 Summer Reliability Forum, Mr. Carl Chapman (Chairman, President, and CEO) commented that, in his opinion, Vectren made an effort to analyze the potential risks faced by Vectren by constructing three portfolio themes. However, he noted in retrospect, after reviewing the Director's Draft Report that the assumptions used for alternative scenarios and sensitivities could have been more significant while still being plausible and allowing the model to solve for the most reliable, resilient, and economic solution. Mr. Chapman specifically mentioned the potential ramifications of the Clean Power Plan.

Additionally, Mr. Chapman noted that a large customer had decided to install Combined Heat and Power (CHP) despite Vectren offering rates that, in Mr. Chapman's opinion, would have made the customer's decision uneconomical. Mr. Chapman recognized that customers may make decisions to install Combined Heat and Power for a variety of reasons. This view was discussed by Vectren on page 2 of Vectren's response to the Draft Director's Report. Vectren states it recognizes the potential of CHP and will consider how to integrate this into the load forecast and future resource planning. [1]

The Director agrees with Mr. Chapman and Vectren's response to the Draft Report and recognizes the significant risk to Vectren and its customers of CHP. The Director also agrees with Vectren (page 112 of

[1] On page 22 of Vectren's IRP, Vectren cites as one of three developments that they must focus on for impacts on the near term is the impact on Vectren's load due to the addition of or loss of large customer load. On page 46, Vectren notes that 48% of sales were consumed by more than 100 large customers. They note significant general service and large load creates complexity in load forecasting. They also go on to say these customers have the ability to significantly impact Vectren's demand for electricity, as economic factors affect their business success. On page 211, Vectren notes a very large customer is considering CHP and that Vectren needs to better understand how this will affect the load forecast. Also on page 211, Vectren says there are four major risks of retiring FB Culley 2 in the next few years. One of which is uncertainty about customer load due to the installation of a large CHP unit. This comment appears to be referring the current large customer listed immediately above. The result is that Vectren recognizes there is considerable risk associated with large customers being added, departing, reducing operations, or perhaps adding CHP. However, their load forecast variations only reflect the addition of new large customer load or the new load largely offset by the new customer using CHP to meet a majority of its load. Nowhere does Vectren explicitly incorporate this concern rather, there is merely a brief discussion of the possibility of more customers adding CHP with the observation that greater adoption of CHP is too difficult to project.

Vectren's IRP) that it is difficult to predict the adoption of CHP and, since CHP isn't a trend and is not common, it is difficult to incorporate potential CHP into the load forecast and the resulting planning analysis. Vectren (like any Company) might be able to make assumptions about size and timing of hypothesized reduced load due to CHP without having to predict the occurrence. That is, the purpose is to assess the potential of increased penetration of CHP happening, not to predict when it's actually happening.

The larger problem is that it is not obvious that Vectren has adequately reflected the extent of uncertainty regarding the load forecast which is due to many factors including large customer adoption of CHP and the addition, expansion, reduction, or termination of operations by some large customers. This is also addressed in the section below on the load forecast.

The Director also had a concern with the lack of explanation for the three basic portfolio themes developed by the company.

Vectren's Comments Regarding Risk Analysis Specifically, beginning on page 193 of their IRP and reiterated on page 1 of Vectren's response to the Director's Report, Vectren described their development of three alternative futures through different scenarios and sensitivities. "*Vectren's IRP evaluated three basic portfolio themes: a base portfolio which included continued operation of the existing generation fleet; a portfolio that evaluated the impact of retiring Culley Unit 2* [Director's note: Vectren is commended for this portfolio being responsive to stakeholder input] *and a portfolio that evaluated the impact of adoption of a renewable portfolio standard that required 20% of electricity to be produced with renewable resources (IRP, page. 33)…The RPS option was selected as a factor other than growth that could reshape the existing portfolio and also responds to the need to diversify the generation fleet over time. Vectren recognizes opportunities to enhance the sophistication of its portfolio themes in future IRPs. In a recent proceeding before the Commission (Cause No. 44446), Vectren engaged a consultant to help evaluate the optimal retirement date for its existing generation units based on a variety of factors. Such modeling may be beneficial in future IRPs to develop potential portfolio themes. In addition, Vectren will elaborate on the process for selecting its basic portfolio themes in future IRPs."*

Director's Response The Director agrees with Mr. Chapman's assessment that the number of scenarios conducted by Vectren may have been sufficient but the limited magnitude of the potential and plausible risks was the over-riding concern. In addition to the broad array of risks identified by Vectren and as further demonstrated by the Combined Heat and Power issue, it is a challenge for any company to plan in a low or negative load growth environment.

To repeat the concerns the Director raised in the Draft Report, the IRP document does not offer a clear narrative to articulate how Vectren determined the three basic portfolio themes. Page 1 of Vectren's responses has a paragraph briefly explaining the development but this foundation should have been developed in the IRP.

The application of these three portfolio themes, regardless of their basis or foundation, to the four load forecasts does not, in the opinion of the Director, constitute sound scenario development. The twelve scenarios are all using the same base set of assumptions and inputs regarding the trajectories of natural gas price, electricity market price, and carbon price. Vectren in their comments on the Draft Report notes that it did evaluate three trajectories of natural gas price, electricity market price, and carbon price. But, in the opinion of the Director, these should have been regarded as sensitivities rather than scenarios.

Scenarios must reflect a range of potential futures that are possible even if some are thought to be unlikely. Scenarios should reflect a wide range of possibilities including very different assumptions about natural gas prices, electricity market prices, and carbon prices. Without this type of analysis, any resulting scenarios are too limited to adequately understand the potential implications of a very uncertain and risky environment that Vectren discusses in the IRP but does not adequately address. Sensitivity analysis is not a substitute for thorough scenario analysis, it is rather a complement. Failing to perform this type of risk and uncertainty analysis means that there are questions as to whether the resource plan developed by Vectren is sufficiently robust, resilient, and appropriate.

For these reasons, the Director is appreciative of Vectren's willingness to consider a more expansive assessment of potential risk in their future IRPs. Specifically, the Director is gratified by Vectren's comments on page 2 of their comments on the Draft Report, *Vectren recognizes opportunities to enhance the sophistication of its portfolio themes in future IRP. In addition, Vectren states it will elaborate on the process for selecting its basic portfolio themes in future IRPs. This includes a willingness to evaluate the optimal retirement date for existing generation units based on a variety of factors in future IRPs to develop potential portfolio themes.* Page 1 of Vectren's response to the Draft Director's Report.

<u>Load Forecasting</u>

<u>Vectren's Comments Regarding Load Forecasting</u> Beginning on page 66 of their IRP, Vectren states: *Vectren developed low, base, and high forecasts of annual energy sales and requirements…and peak loads… for the purposes of its IRP.* Vectren is forecasting a -0.2% compound annual change in base case energy use and a -0.1% compound annual change in base case peak demand over the 20 year planning horizon. On page 69 of their IRP, [The] *low and high energy and demand forecasts were developed by* *modifying the assumptions around conservation, distributed generation adoption, economic drivers, population projections, and large customer additions…In the high growth forecast, economic growth was increased from approximately 1% to 2% and population growth was increased from about 0.3% to 0.5%. The high growth (large load) case is the same as the base case, with the addition of a large customer in 2018.*

<u>Director's Response</u> The Director believes Vectren's base case forecast was a reasonable exercise of Vectren's professional judgment for their Plan. From the Director's perspective, Vectren treated the high and low load forecasts more akin to scenarios rather than as sensitivities from the base case forecast combining changes involving conservation, Distributed Generation (DG) adoption, economic drivers, population projections, and large customer additions. For example, based on pages 84-88, the DG forecast varies for each load forecast. That is, each alternative load forecast has factors – perhaps several factors / variables that are different. Care should be taken to ensure consistency with the changes to the variables (e.g., so that you don't have a higher economic growth combined with a lower population growth) and a narrative to explain the load forecast. However, from the Director's perspective, Vectren's high growth (large load) forecast seems to be the exception because it is essentially a sensitivity off the base forecast since the only difference between the two is the addition of one large customer in 2018.

The Director's concern is heightened because the IRP is silent about the drivers of the low load forecast – a discussion of what makes it low is missing beyond very general statements. On page 4 of their Comments on the Director's Draft Report, Vectren states the low load forecast includes alternate assumptions for several factors – a greater impact for customer-owned DG, a higher level of conservation. Also, it is assumed that a new potential large customer locates in the area but uses CHP to generate the majority of its power. Vectren explicitly notes the low load forecast is not based on changes to the economic forecast. The Director does, however, recognize that given the dynamics of the Vectren system that suggest sustained low (or negative) load growth, that load forecasting is difficult. The Director recognizes there may only be limited load growth in Vectren's service territory, which limits consideration of some resources in the IRP and compounds the difficulties of incorporating customer-owned resources and DSM into the load forecasts and planning analysis.

The Director is also concerned that the load forecast methodology used by Vectren might seriously understate the extent of uncertainty associated with load. There are several ways to develop a range of load forecasts and it is not obvious that one is necessarily better than another. But it is staff's concern that most understate load forecast uncertainty and that this is not adequately recognized by the utility and other stakeholders. For example, if an econometric formulation is used, you can use the standard deviation of the error term in the model formulation to derive the low and high forecasts (for instance, they can be two standard deviations from the mean). In doing this, you don't need alternate economic projections. It tends to understate the uncertainty because you treat your drivers as having no uncertainty. It is also appropriate to use alternate economic assumptions. But only having alternate projections for just some economic drivers means some other drivers (like population) don't change between the high, base, and low forecasts. This also tends to understate the differences.

As described above, Vectren's approach to developing base, high, and low load forecasts makes it difficult to judge how well Vectren captured the extent of load forecast uncertainty. The lack of detailed discussion as to how the high and low load forecasts were developed means it is difficult to judge how well Vectren has reflected the extent of load uncertainty. The Director believes this is especially a problem for the industrial sector given that Vectren highlights in a few places its dependence on significant industrial load concentrated among a few very large consumers.

A focused effort to better estimate the extent of load forecast uncertainty helps address simultaneously the issues of what happens if a large customer reduces or eliminates production or installs CHP to meet a significant proportion of their load. Similarly, a more concerted effort to estimate load forecast uncertainty would benefit Vectren if it were to experience an increase in the industrial sector. From a load forecast perspective we are trying to adequately reflect the extent of uncertainty regardless of any one specific reason such as installing CHP or reducing operations. The nature and degree of uncertainty should, then, be developed in a consistent narrative that would be used in the construction of future scenarios and their sensitivities.

Vectren's Comments Regarding the Stakeholder Process Vectren's President and CEO, Carl Chapman, attended all of the Stakeholder Sessions and made his subject matter experts available throughout the IRP process. During the Summer Reliability Forum, Mr. Chapman said that Vectren is committed to making continual improvements to the stakeholder process so that it is meaningful even if Vectren doesn't satisfy every stakeholder's expectations or suggestions. Mr. Chapman and the CEOs of other Indiana Investor-Owned Utilities expressed the concern that the IRP process not be used to drive a specific resource mix.

Director's Response The Director commends Mr. Chapman and the Vectren staff for their commitment to the IRP process and to continual improvement. The Director is very appreciative of the comments by Mr. Chapman that meaningful stakeholder input will better assure objectivity and reduce the potential for the IRPs to confirm preconceived resource plans.

The Director believes that Vectren's analysis of the Culley Unit 2 and the RPS are both responsive to comments by stakeholders but there is still room for improvement, which Vectren has acknowledged. Vectren recognized in its comments on the Draft IRP Report that there are opportunities to enhance the sophistication of its portfolio themes in future IRPs. Specifically mentioned was the potential to include more modeling to better evaluate the retirement date for its existing generation units based on a variety of factors (Page 1Vectren Comments).

With regard to transparency, the Director was very appreciative of Vectren's willingness to rely on publically available information. We believe this enhances the stakeholder process. Hopefully, other utilities will follow Vectren's lead in this regard.

4. HOOSIER ENERGY's INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

This Final Director's Report reflects the following issues and emphasizes those that the Director regards as the most important concerns. This does not address all the questions and concerns raised by the Director or stakeholders in the Draft Director's Report on the 2014 IRPs. The issues are:

- Risk Analysis
- Load Forecasting
- DSM

General Observations The Director recognizes the structure of Hoosier Energy and its members are different from vertically integrated electric utilities. The regulatory relationship with the IURC is also different. The structural differences pose both problems and opportunities for Hoosier Energy to coordinate the long-term development of a resource plan that, as Hoosier Energy's IRP states on page 11 and consistent with the IRP requirements, includes "*conservation, load management, co-generation, distributed generation, refurbishment of an existing facility, and purchase of power as alternatives to construction, purchase or lease of an electrical generating facility*."

In some regards, Hoosier Energy's ability to undertake integrated resource planning is more difficult. The Director also recognizes the structure of Hoosier Energy has some potential advantages due to the ability of member cooperatives to tailor their programs more precisely to their members needs. Notwithstanding the structural and regulatory differences, the significant risks that the Hoosier Energy system will be confronting are, with few exceptions, the same as those faced by Investor-Owned Utilities (IOUs) and the potential financial implications can be significant.

Notwithstanding the structural and regulatory differences between Hoosier Energy and their investor-owned counterparts, the Commission must adhere to its statutory requirements. In this instance, the Commission is statutorily obligated to ensure reliability – including resource adequacy – for all utilities in Indiana. For the Commission to meet its statutory obligations, the Commission must have confidence in the resource plans of Indiana utilities. The Director's comments must, therefore, hold Hoosier Energy to the same standards as those of IOUs.

Director's Comments Regarding Risk Analysis Given the Commission's statutory obligations to approve new generating resources and responsibility for resource adequacy, all Indiana utilities must be able to demonstrate that they have undertaken an objective analysis of the wide array of risks, the potential ramifications of these various risk factors for reliability and economical service, and require utilities to provide a well-reasoned discussion of potential mitigation strategies to address possible futures. As Hoosier Energy noted, on page 12 of their IRP "*…additional environmental restrictions have the potential to dramatically affect cost assumption tradeoffs between the type, quality and availability of fuel burned and the allowable emissions level at Hoosier Energy's existing and future generating stations.*" Increasingly aggressive environmental regulations *may* significantly alter the region's and nation's resource mix. The environmental risks identified by Hoosier Energy are also significantly influenced by the relatively low trajectory of natural gas price forecasts. As a testament to the risk of these forecasts, current projections would have been regarded as unrealistic a few years ago. Just in the last few years, there have been significant decreases in the cost of renewable technologies. It is possible we are experiencing a paradigm change to a long-term low-load growth (maybe negative for some utilities) in part due to energy efficiency. It's also possible that large customers will increasingly invest in distributed generation resources even if the utilities do not regard these investments as economically justified. A robust analysis of risk – including relatively low probability events that are very consequential for reliability and the economic provision of electricity- are integral to the IRP requirements.

On page 1 of Hoosier Energy's response to the Draft Director's Report, Hoosier Energy responds that, in their opinion, they have done enough to evaluate potential reliability and economic risks to their member cooperatives and, by extension, to their members that are dependent on Hoosier Energy. In their response to the draft report's critique of limited risk analysis, Hoosier Energy cites the "The Federal Environmental Legislation Scenario" as having the highest Net Present Value compared to their preferred Plan. While the Director understands the Federal Environmental Legislation Scenario isn't Hoosier Energy's preferred option, to some extent, Hoosier Energy may have to confront this scenario. Especially given the concerns raised by Hoosier Energy, Hoosier Energy's statement leaves the perception that their preferred solution was pre-ordained rather than the product of an objective analysis of the spectrum of potential risks.

This possible future was recognized by Hoosier Energy in the IRP [2] and during the Summer Reliability Forum as a significant risk to Hoosier Energy and its members. Hoosier Energy's representative remarked they are proposing an alternative to the Environmental Protection Agency Clean Power Plan that would allow Hoosier Energy to continue to rely on their coal fleet much longer than the EPA's possible regulations – if approved - *may* allow.

Of course, in addition to the risks associated with the Clean Power Plan recognized by Hoosier Energy, Hoosier Energy also identified other environmental regulations that affect Hoosier Energy's resource plans. Additionally, Hoosier Energy recognized the dynamic changes in the forecasted price of fuels, changes in the cost-effectiveness of energy efficiency, changes in the penetration of customer-owned/distributed generation, the potential for greater reliance on renewable energy, economic changes, regional power supply and demand considerations, etc. that should be integrated into a robust assessment of risks to reliability and the economic provision of power.

Hoosier Energy's recognition of the extent of uncertainty and the potential ramifications is in considerable contrast to what Hoosier Energy did in the integrated resource plan. Hoosier Energy only developed two scenarios, only one of which was subjected to sensitivity analysis. The scenarios were a base case and Federal Environmental Legislation Case which was based on a Ventyx scenario fashioned off a combination of bills introduced in the 112th Congress related to greenhouse gas legislation. In this scenario, gas prices, market prices, and carbon emission costs were all changed. However, sensitivities were only done on the Base Case - High Load Growth, Low Load Growth, High Gas Price, and Low Gas Price. An optimal resource plan was developed for each of the six cases. It seems that Hoosier Energy chose the optimal plan for the base case as the preferred resource plan.

Hoosier Energy did not perform any sensitivity analysis on the optimal plans identified by the Strategist model. However, more extensive scenario and risk analysis is necessary because Strategist does not take into consideration risk factors. As Hoosier Energy noted in the IRP: "*The Strategist model runs hundreds of scenarios to select an optimal or least cost combination of resources. It does not consider any other factors such as risk, potential market changes, regulatory/environmental considerations, etc. Management*

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[2] *EPA released the proposed green house gas rule for existing plants in June 2014 and this new regulation represents the primary risk to consistent operation of coal-fired facilities*. Hoosier Energy recognized the four building blocks including increased reliance on renewable energy and energy efficiency. Hoosier Energy also *acknowledged MISO is uniquely positioned to identify reliability concerns that may result due to the accelerated retirement or reduced output of existing units. Increased reliance on natural gas CCs, additional renewables, and the short compliance timeline*. (page 53 of Hoosier Energy's IRP)

must evaluate the model results in conjunction with judgment about these other factors." page 95 of Hoosier Energy's IRP.

It is less clear how Hoosier Energy would factor in various risks and uncertainties into the resource planning process without more systematic scenario and sensitivity analysis.

Hoosier Energy's Comments Regarding Load Forecasting Hoosier Energy notes that each of its 18 member systems conducts their own load forecasting process based on their *Power Requirements Study* that is conducted every two years. Hoosier Energy also notes that their members utilize load forecasting models that are proprietary. Hoosier Energy, page 16 of their IRP, observes that their load forecast is conducted to: *1) provide a basis for determining generation, transmission, and distribution capital requirements; 2) Develop a consistent framework for Hoosier Energy and the member systems to plan and project system-wide improvements; and 3) Satisfy the requirement by the RUS (Rural Utilities Service) that generation and transmission cooperatives provide empirical studies ..that are consistent with system projections, and that reflect an understanding of the system, its loads, its member systems, and its power supply*.

As Hoosier Energy noted on page 19 of their IRP, *the erratic nature of the historical data and the composition of the varied types of loads in this class make it difficult to explain the growth in sales for the Commercial, Industrial, and Other class accurately using an econometric model.* Hoosier Energy, while especially noting the risks associated with serving industrial customers, comments that each member cooperative relies heavily on its relationships with commercial, industrial, and other customers as the basis for their forecasts of this diverse group of utilities which the Director understands is based on judgment for each of these groups of customers within this broad group. On pages 18 and 19 of their IRP, Hoosier Energy discusses their "Commercial, Industrial, and Other" *model* which, while relying on informed judgment, obviously lacks the attributes of a well-designed forecasting model that includes tailored drivers for different types of customers (e.g., explicit economic drivers, end-use information, the cost of electricity, the cost of alternative fuels, weather, employment data, etc.). During the member cooperatives' interviews with their commercial, industrial, and other customers, some factors that drive business decisions may have been discussed but there is no mention of how the results of these interviews were factored into the analysis.

Director's Comments Regarding Load Forecasting The Director understands that Hoosier Energy totals the forecasts developed by their member cooperatives for this entire diverse class. If our understanding is correct, it is difficult to imagine Hoosier Energy or their member cooperatives can gain the wealth of information commensurate with the risks / concerns that Hoosier Energy has described. Since Hoosier Energy has responsibility for meeting their members' needs, it doesn't seem that Hoosier can gain appropriate insights of future energy use or demand characteristics from this gross aggregation of each member's commercial, industrial, and other customers. Recognizing the limitations, the Director commends Hoosier Energy for their efforts to give effect to load forecast uncertainty (page 25 of their IRP) for this important group of customers.

In the Director's critique of the IRPs, we've stressed the goal of the IRPs was more about developing credible load forecasts as well as all other aspects of the IRP than it was the expectation that the utilities' Plan or alternative futures would be precise; especially for the entire planning horizon. The Director hopes future IRPs will provide a more detailed discussion of Hoosier Energy forecasting methods and processes for the commercial, industrial, and other customer class. If the Director's understanding of Hoosier Energy's forecasting methods is accurate, we hope Hoosier Energy and their members would give careful reconsideration to their processes and methods.

Hoosier Energy describes their residential forecasting models (beginning on page 17 of their IRP) but characterizes the Residential Forecast as "*simply the summation of the results from the individual member system's econometric Residential Model*. For future IRPs, the Director would like to have a better understanding of how the members' forecasts for all classes of customers are integrated into the Hoosier Energy load forecasts.

Hoosier Energy provided a good discussion of the development of the base case and alternative load forecast scenarios (page 25 of their IRP).

Hoosier Energy correctly noted that their load forecasts risks can be very significant. The possibility of systematically over or under-forecasting customer usage has significant implications for future resource requirements (e.g., too much or too few resources) and the cost to Hoosier Energy's member cooperatives and their customers. Based on the responses from Hoosier Energy to the Draft Director's Report, there doesn't seem to be any concern that the load forecasting process might benefit from a critical review of ways to improve the: data bases, forecasting methods, analytical tools, and the integration of the forecasts to construct a Hoosier Energy system load forecast. The Director, consistent with the proposed IRP Rule, encourages continual improvements in the load forecasting process because it is foundational to a well-developed long-term resource plan. Regarding the aspiration for continuing improvements, the Director was encouraged that Rural Utilities Service (RUS) recognizes the importance of load forecasting, especially for the commercial, industrial, and other customers, and offered suggestions about Hoosier Energy's forecasting process for commercial, industrial, and other customers. page 19 of Hoosier Energy's IRP.

Demand-Side Management Hoosier Energy states: *DSM does compete on a level playing field with traditional supply-side resources, however, this simply is done outside of the Strategist resource planning* *model. Hoosier Energy develops estimated costs for a number of resources and compares those to the most likely supply-side resources – natural gas-fired simple and combined cycle generation. The identification, development and selection of the DSM programs is performed jointly with Hoosier Energy member systems.* page 2 of Hoosier Energy's response to the Draft Director's Report.

<u>Director's Comments Regarding Demand-Side Management</u> Given the organizational structure of Hoosier Energy and the inherent difficulties of trying to treat DSM in a comparable manner to traditional generating resources, the Director understands the difficulties faced by Hoosier Energy. However, saying that DSM evaluation is "simply done outside of the Strategist resource planning model" raises concerns that DSM isn't being evaluated on a comparable basis to other resources. That is, how can the evaluation of cost-effective DSM be separate but equal to other resources if they are not truly integrated? For future IRPs, the Director would like Hoosier Energy to address how the bundling (preprocessing) of DSM outside of the Strategist model is capable of treating cost-effective DSM on a comparable basis to generating resources. Referring back to Hoosier Energy's consideration of risk analysis and their concern about the significant implications of the Clean Power Plan, how would Hoosier Energy respond IF the Clean Power Plan rule was approved and DSM was a significant compliance method? Staff is particularly concerned that the treatment of DSM by Hoosier Energy has the potential to understate the effectiveness of both energy efficiency and demand response for addressing uncertainty involving so many aspects of the long-term resource planning process.

The Director would like to acknowledge Hoosier Energy's 2010 change to its wholesale tariff that is intended to encourage demand response and Hoosier Energy's Board directive to obtain 10% of its member energy requirements by incorporation of renewable resources in 2025. pages 13 and 45 of Hoosier Energy's IRP. The Director assumes that this amount would be flexible depending on future IRPs. The Director commends Hoosier Energy for offering tailored rate programs to facilitate cost-effective renewable energy (and DSM) for the benefit of their member cooperatives and their members.

The Director hopes future IRP's prepared by Hoosier Energy, consistent with the varying potential importance of DSM under a variety of contingencies, will assess its current processes and analytical methods in an effort to improve the integration of DSM into their IRP. The Director would also encourage more developed discussions of the potential role of DSM in the various scenarios and sensitivities.

The Director recognizes the structural and regulatory differences between Hoosier Energy and Indiana's Investor-Owned Utilities. However, the reliability and economic risks faced by both Hoosier Energy and IOU's are very similar. The Director hopes that Hoosier Energy's future IRPs will provide a more robust and objective analysis of potential risks, consider improvements in the load forecasting (i.e., processes, analytical tools, and data bases) and better integrate cost-effective DSM into Hoosier Energy's resource planning process. Well-developed narratives should be developed to address all aspects of the Integrated Resource Plan.