

**INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S ("OUCC")**  
**COMMENTS ON 2014 INTEGRATED RESOURCE PLANS ("IRPs") OF**  
**VECTREN SOUTH, IPL, NIPSCO AND HOOSIER ENERGY**

**A. INTRODUCTION**

The OUCC's comments begin with general observations common to the 2014 IRPs before offering specific comments on each of the four (4) individual 2014 IRPs: (i) Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South"); (ii) Indianapolis Power & Light Company ("IPL"); (iii) Northern Indiana Public Service Company ("NIPSCO"); and (iv) Hoosier Energy Rural Electric Cooperative, Inc. ("Hoosier Energy").

These comments identify a few areas for improvement in modeling assumptions, transparency, and future challenges due to technological developments that might significantly impact future efficiencies in both utility provisioning and customer use of electricity. These comments also identify questions or concerns unique to individual utility IRPs, ranging from environmental issues (e.g., assumed carbon prices and demand side management ("DSM") plans) to the condition of electric utility facilities impacting future system needs (e.g., planned generating unit retirements and safety concerns).

**B. GENERAL COMMENTS**

**1. Current IRP Modeling**

As discussed on page 10 of the April 30, 2014 *Report of Indiana Utility Regulatory Commission Electricity Division Director Dr. Bradley K. Borum Regarding 2013 Integrated Resource Plans* ("Dr. Borum's 2013 IRP Report"), 170 I.A.C. 4-7-8 requires utilities to demonstrate how the preferred resource portfolio balances cost minimization with cost-effective risk and uncertainty reduction. It is important that the preferred IRP portfolios are based on sound modeling with reasonable and transparent assumptions, while also considering elements such as political outlook, risk, portfolio mix and human behavior, since these elements can impact the costs of different alternatives. As stated on page 18 of *Dr. Borum's 2013 IRP Report*, "One purpose of an IRP is to explore what is probable or realistic, but a larger purpose is to explore those things that do not seem plausible today but could happen." The utilities did not demonstrate in a clear manner whether these qualitative elements were considered and, if so, how they were accounted for in the modeling process. It also is unclear whether the utilities' modeling considered the availability of a renewable resource at peak load or the need for and cost of available back-up energy through spot or long term contracts for purchased power.

## 2. Hardwiring DSM Resources into IRP Cost Models

Three of the four utilities' 2014 IRPs hardwired DSM resources impacts over the modeling period. This resulted in a predetermination of the level of DSM resources that may or may not have been selected, and possibly at a higher or lower level, if allowed to compete with supply side resources in the modeling process. This issue was discussed in *Dr. Borum's 2013 IRP Report*.<sup>1</sup> The OUC is concerned that, except for NIPSCO's IRP, this year's IRP modeling did not comply with Dr. Borum's instructions.

*Dr. Borum's 2013 IRP Report* discussed the importance of utilities demonstrating that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis.<sup>2</sup> This requirement cannot be accomplished by "hardwiring" DSM (*i.e.*, by reducing the expected load by a pre-designated level of DSM energy savings) before running the model.

The selection of DSM programs as a supply side resource can be materially impacted by the cost of those programs. The modeling should reflect not only the cost to the utility but also additional revenue to be recovered from utility customers as lost margin or net lost revenues and shareholder incentives. That additional utility revenue should also be considered in developing any net present value of projected revenue requirements.

## 3. Modeling for Distributed Generation

170 I.A.C. 4-7-4(4) requires the IRP to include not only a discussion of distributed generation, but also the potential effects on generation, transmission, and distribution planning and load forecasting. Depending on how distributed generation is recognized, the price utilized will impact its selection. Other considerations also include ratepayer adoption of the technology and whether the ratepayer actually uses less utility-generated energy.

A typical feed-in tariff requires a utility to purchase power at rates typically higher than the average amount per kWh paid by ratepayers. That could tilt any model to negatively value distributed generation. An assumption has to be made as to whether ratepayers will actually purchase distributed generating facilities in the capacity assumed and whether those ratepayers will actually use less utility-generated electricity after purchasing their own distributed generation facility.

Hardwiring distributed generation based on actual experience may be a better approach because of the cost differences between the various rates designed to capture distributed

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<sup>1</sup>See discussion on pages 4 through 7, 11 through 13, 21, 27 and 31 of *Dr. Borum's 2013 IRP Report*.

<sup>2</sup> *Id.*

generation. Some rates are economical while others may be set too high to attract a projected level of participation.

#### 4. Addressing Future Technological Developments

It is reasonable to expect further technological advances in electric utility infrastructure. This would also apply to industrial users' on-site generation and energy management capabilities. Future increases in industrial customers' use of combined heat and power ("CHP"), co-generation, and energy management systems ("EnMS")(e.g., ISO 50001 and the U.S. Department of Energy's Superior Energy Performance (SEP) program), could significantly impact future average and peak loads. Customer decisions to make (or refrain from making) future facility or operational improvements are outside Indiana electric utilities' control. Historical data may not be useful in projecting such change. However, given the potential impact of losing large industrial customer load as new industrial trends emerge, utilities will need to account for the impact of these technological advances in their load forecasts.

Further, as electric utilities explore ways to implement Smart Grid and/or other technology-driven system improvements, utilities will pursue varied strategies targeting different levels of efficiency improvements to be implemented on unique schedules. As new technology drives future efficiencies in energy supply (generation, transmission and distribution) and future reductions in load, IRPs should clearly identify and fully explain the reasoning behind any new factors considered in IRP modeling and any differing values assigned to those factors during the relevant planning horizon.

### C. COMMENTS SPECIFIC TO VECTREN SOUTH'S 2014 IRP

#### 1. Non-Technical Summary

Although the table on page 10 in Vectren South's Non-Technical Summary shows costs for each plan (A1-C4), the percentages used in the table were not explained. Further clarification would provide customers with a better understanding of the plans, especially since they might only choose to review the Non-Technical Summary.

Vectren South evaluated the possible retirement of Culley 2. The Culley facility is located on the banks of the Ohio River, with limited space for additional equipment such as potential cooling towers for wastewater treatment and potential coal ash pond modifications. Therefore, space limitations could increase the cost of future compliance options.

Vectren South has a combined FGD for Culley Units 2 and 3 (installed 1994). If Culley 2 is retired, Vectren South may need to obtain an updated FGD for Unit 3. The EPA also has opacity concerns at Culley which could require costly FGD bypass modifications to remedy.

The costs to achieve environmental compliance for Culley 3 alone could be almost as high as the combined cost for retiring both Culley 2 and Culley 3. Most of the environmental compliance costs for air, water and waste pollutants will result from improvements required for Culley 3, which at 270 MW is three times the size of Culley 2 (90 MW). The retirement of Culley Unit 2 alone would not significantly decrease environmental compliance costs for this facility.

## **2. Vectren South's 2014 IRP**

Vectren South's list of IRP objectives (page 31) includes "past and current impact minimization of future operations on local environments," but fails to mention future impact minimization, something the OUCG would expect to see addressed in a forward-looking planning document.

The OUCG recommends that Vectren South clarify which sources were used for its sensitivity analyses. (See the Potential Sources column on page 204, Table 10-8, Sensitivity Summary Table used for stress tests).

For example, it is not clear which carbon forecast was used in Vectren South's IRP analysis. Synapse is shown as a potential source of that forecast. However, there are several Synapse carbon forecasts. The MTEP 15 is also identified as a potential source for the carbon forecast. It is unclear which carbon forecast source was used in Vectren South's analysis.

The Carbon Pricing Forecast Inputs on page 68 of the Stakeholder Meeting materials, Real 2013\$/Ton (Waxman-Markey) do not match the high and low carbon price values (sensitivities) shown on page 204 of Vectren South's 2014 IRP. Although a high and a low price per ton are provided in Table 10-8, additional details on how those inputs were modeled would help clarify Vectren South's carbon price evaluation.

The OUCG recommends that Vectren South include a full explanation of its carbon price modeling as well as sensitivities showing a low carbon price, a high carbon price, and a break even price (i.e., the price at which Vectren South would make different generation choices). These revisions would improve the clarity and usefulness of Vectren South's carbon modeling.

## **3. DSM Resources**

On page 132 of its IRP, Vectren South indicates that it "...will include an on-going level of Vectren South sponsored DSM in the load forecast and will also consider additional DSM as a source of supply in meeting future electric service requirements..." Vectren South expects "...the described level of ongoing DSM energy efficiency programs included in the base sales forecast ... [to be] available to all customer classes at a targeted level of 1% eligible annual savings for 2015-2019 and 0.5% annually thereafter for customer load that has not opted-out of

DSM programs.”<sup>3</sup> Vectren South also believes that “...a cost effective level of DSM energy efficiency may be supported by policy considerations beyond capacity planning which are not always captured in the IRP modeling process.”<sup>4</sup>

While the OUCC appreciates Vectren South’s commitment to offering DSM programs, the Indiana Utility Regulatory Commission’s current IRP Rule and its draft proposed revisions to that rule require utilities to demonstrate that “...supply-side and demand-side resource alternatives be evaluated on a consistent and comparable basis”<sup>5</sup> rather than simply hard wiring DSM savings into a utility’s IRP model. Dr. Borum emphasized this requirement in his 2013 IRP Report. OUCC staff reiterated Dr. Borum’s admonition during Vectren South’s IRP Stakeholder Meetings, questioning Vectren South’s choice to “hard wire” or build a predetermined level of DSM into its IRP model. In response, Vectren South indicated that it has adopted a conservation culture and that it plans to include a certain level of DSM in future resource planning, regardless of IRP modeling results. The OUCC recommends that if Vectren South wishes to hard wire a certain level of DSM into its IRP model, that it should also run a separate scenario allowing the model to identify a cost-effective level of demand-side resources as part of the IRP process. This approach would allow Vectren South to comply with the Commission’s IRP rule and also provide transparency to stakeholders with regard to least-cost planning.

On page 152 of its IRP, Vectren South indicates energy efficiency measures considered for the programs were developed using existing Indiana utility program measures (whenever possible) and measures used in other programs in the Midwest. The OUCC recommends that Vectren South use the Indiana Technical Resource Manual (“Indiana TRM”) until actual Evaluation, Measurement and Verification (“EM&V”) results are available to determine savings for individual program measures. Once available, company-specific EM&V results should be used.

#### **D. COMMENTS SPECIFIC TO IPL’S 2014 IRP**

##### **1. Non-Technical Summary**

IPL discussed its preferred portfolio in the Non-Technical Summary on page 7 of its 2014 IRP. It is not clear why Petersburg Units 1 and 2 were considered for early retirement or whether they were the only units in IPL’s fleet that were considered for early retirement. Plan 1 appears to be the most robust plan, with the most scenarios modeled. Nevertheless, under the high environmental cost scenario, Plan 1 would not be the preferred plan. That risk factor was

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<sup>3</sup> *Id.*

<sup>4</sup> *Id.*

<sup>5</sup> 170 I.A.C. 4-7-8(b)(3).

not discussed in the text of IPL's IRP; it should have been identified as a major risk factor under IPL's preferred portfolio.

**2. IPL's 2014 IRP**

Regarding Figure 1.2 – IPL Facilities on page 4, IPL should identify the unforced capacity (MW), primary fuel, and commercial date of each unit at each facility. Looking at the Comparative Air Emissions by Resource Plan on page 75, IPL's preferred plan, Plan 1, has the highest NO<sub>x</sub>, SO<sub>2</sub> and CO<sub>2</sub> emissions. Depending on pending environmental regulations, this plan may not be the preferred choice. The OUCC recommends IPL identify major risk factors to its preferred portfolio in its IRP.

On page 44, Figure 4.2 - MISO Zones is blank except for a small section of the bottom left hand corner of the map. The missing portions of that map should be included in Figure 4.2.

**3. Demand Side Management - Section 4B**

During IPL's IRP Stakeholder Meetings, the OUCC technical staff questioned IPL's choice to hard wire DSM into its model in light of *Dr. Borum's 2013 IRP Report*. In response, IPL indicated that it views DSM as an essential resource, and will include a predetermined amount of DSM.

On page 97 of its 2014 IRP, IPL indicates that "...the forecast of future DSM (2018-2034) that was completed by Applied Energy Group is discussed and incorporated in IPL's Load Forecast (Section 4D) and modeled by Ventyx in the Integration section (Section 4)." IPL's IRP also states on page 122 that "...future public policy, including the Clean Power Plan and Indiana's legislative direction, will influence IPL's determination of the appropriate level of DSM beyond 2017." Based on those statements, it appears that IPL plans to continue to hard wire DSM into its IRP model.

While the OUCC appreciates IPL's commitment to DSM, the Commission's IRP rule indicates DSM should be allowed to compete against supply-side options. (*See* 170 I.A.C. 4-7-6 and 4-7-7.) That is not consistent with hard wiring a certain level of DSM into IPL's IRP model.

Consistent with the OUCC's recommendation as to Vectren South's IRP, if IPL includes a level of DSM that is hard wired into its IRP model, it should also run a separate scenario that allows the model to select demand-side resources without any hard wiring. That approach would allow IPL to satisfy the IRP rule, while also providing transparency to stakeholders regarding least cost planning.

**4. Transmission & Distribution - Section 4C**

On page 134 of its 2014 IRP, IPL discussed the following point:

SCADA functionality was extended to the Central Business District (“CBD”) network in downtown Indianapolis through network protector relays and communicating fault indicators on the network.

The OUC notes that the CBD network serving downtown Indianapolis is an underground distribution system. Exploding manholes in the CBD network have been a major problem over the last five (5) years. Extending SCADA functionality to the CBD network could help identify some of the causes of the explosions. The added network protector relays and the communicating fault indicators on the CBD network could help prevent, or at least mitigate, conditions that have caused past explosions. The remote device monitoring and control functionality of SCADA could, in the future, help prevent the development of conditions that cause manhole explosions. However, IPL did not discuss the potential merits of extending SCADA to the CBD network to eliminate, mitigate, and/or prevent conditions that might cause future explosions.

**E. COMMENTS SPECIFIC TO NIPSCO’S 2014 IRP**

NIPSCO’s IRP could be improved if estimated environmental costs were identified and explained in the main body of its IRP. For example, the value used for Carbon Breakpoints and Synapse Carbon Sensitivity were not disclosed in the text of NIPSCO’s IRP. Those costs were included in the Sierra Club’s July 16, 2014 presentation, one of a number of lengthy IRP presentations shown in Appendix E to NIPSCO’s IRP. Also, the difference in the environmental costs used in NIPSCO’s base case and its aggressive environmental case are only shown in that presentation. The only environmental cost that was discussed in the main body of the IRP was a reference on page 3 to the \$600 Million that would be spent through 2018 to bring existing units into compliance with additional environmental obligations.

On page 96, NIPSCO indicates that it does not expect to see a price on carbon before 2025. However, in one of its slides in the above presentation, NIPSCO shows carbon modeling starting in 2020 for both its base case and the aggressive environmental scenario. NIPSCO should provide an additional explanation of its use of 2020 as the carbon price modeling start date for those two scenarios.

NIPSCO should also identify major risk factors related to the base case in its IRP to better explain the scenario and the sensitivity choices used in its analysis.

F. COMMENTS SPECIFIC TO HOOSIER ENERGY'S 2014 IRP

Although Hoosier Energy discusses environmental rules and regulations in its 2014 IRP, it did not identify the rules and regulations included in the Federal Environmental Legislation Scenario Optimal Plan. Carbon regulations are mentioned in the environmental factor section; however, it is not clear whether carbon prices were used in the IRP modeling.

In the Conclusion section of its 2014 IRP, Hoosier Energy comments that the Strategist model does not consider other factors such as risk, potential market changes, regulatory/environmental considerations, etc., and that management must evaluate the model results in conjunction with judgments about those other factors. Describing the contents of each scenario and explaining why each scenario was selected would buttress the conclusions reached in Hoosier Energy's 2014 IRP.

With regard to modeling DSM resources, Hoosier Energy staff confirmed that it hard wired a predetermined amount of DSM in its IRP process, rather than allowing the model to select the least cost resource.

Again, OUCG appreciates Hoosier Energy's commitment to DSM; however, the Commission's IRP rule indicates DSM should be allowed to compete against supply-side options. (*See* 170 I.A.C. 4-7-6 and 4-7-7.)

If Hoosier Energy elects to continue hardwiring DSM into its IRP model, it should also run a separate scenario that allows the model to select demand-side resources without any hard wiring. That approach would allow IPL to satisfy the IRP rule, and also provide transparency to stakeholders regarding least cost planning.

Respectfully submitted,

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