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INDIANA UTILITY REGULATORY COMMISSION

RESPONSE OF

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TO THE DRAFT REPORT

OF THE INDIANA UTILITY REGULATORY COMMISSION

DATED MARCH 3, 2015

SUBMITTED: April 2, 2015

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NIPSCO's Response to the IURC's Draft Report

Regarding NIPSCO's 2014 IRP

I. Introduction

On October 30, 2014, in compliance with the Indiana Utility Regulatory Commission's ("IURC") Proposed Rule to modify 170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans ("Proposed Rule"), NIPSCO submitted its 2014 IRP. On March 2, 2015, the IURC's Electricity Division Director submitted his Draft Report of the Indiana Utility Regulatory Commission Electricity Division Director Dr. Bradley K. Borum Regarding 2014 Integrated Resource Plans ("Draft Report") summarizing issues and concerns identified with the four Integrated Resource Plans ("IRPs") submitted by Indianapolis Power & Light Company ("IPL"), Northern Indiana Public Service Company ("NIPSCO"), Southern Indiana Gas & Electric Co. ("Vectren") and Hoosier Energy (the "2014 IRPs"). NIPSCO has joined with IPL and Vectren in submitting joint comments to the general critique of the 2014 IRPs. These responses, including the attached Appendix, are submitted to the specific issues and concerns identified by Dr. Borum in the NIPSCO section of the Draft Report.

II. Risk Analysis

The Commission staff opines that NIPSCO's risk analysis is not as comprehensive as any they would present to their management. As explained in the Joint Comments, this assumption by the Commission staff is flawed. NIPSCO's 2014 IRP reflects its business planning process. NIPSCO's use of scenarios provides a consistent framework to evaluate future investments, strategies and business decisions. The NIPSCO 2014 IRP scenarios focus on a continuation of current business environment, and an environment where more stringent environmental regulations drive higher costs for compliance with greenhouse gas, coal combustion residuals, water and wastewater management rules. Scenarios outline plausible future states of the world. They are helpful to avoid locking into a single view of the future (i.e. "tunnel vision") or simply looking at the future by extrapolating from the past, and help envision a range of potential futures. Scenarios are widely used by companies in capital-intensive industries with long-lived assets. When combined with sensitivities, a wide range of potential futures can be systematically explored. Scenarios are constructed from a broad base of inputs and assumptions from subject matter experts spanning the organization as well as external consultants. Outputs are used to inform corporate initiatives. In the 2014 IRP the 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. Scenarios can assist in highlighting 'no regrets' decisions that work in a range of potential futures (that we may or may not be able to control). A robust analysis examining the outer bounds of probability/plausibility are not prepared for NIPSCO's management, nor is every conceivable remote possibility modeled. Ultimately the utility's customers are responsible for the costs of such analysis(es) and the costs

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versus the benefits of purely academic exercises at points in time when ultimate construction decisions are not being made, should be taken into consideration. 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.

The specific issues and concerns enumerated on pages 23-25 of the Draft Report are addressed in the Appendix, Requests 1-1 through 1-7.

III. Load Forecasting

The Draft Report suggests that NIPSCO's projection that the number of industrial customers and their demand will be constant throughout the entire forecast horizon strains credulity. The Commission staff further believes this is inconsistent with historical information, and the Draft Report goes further regarding this concern. In response to these concerns, NIPSCO would note that its projection that the number of industrial customers and their demand will be constant throughout the entire forecast horizon is derived from conversations with its largest customers. A further response to this concern is included in the Appendix, Request 1-17.

The Commission staff notes that NIPSCO subtracted 377 MWs of DSM from its internal load. The 377 MWs of industrial direct load control ("DLC") is consistent with the amount of demand response that NIPSCO has under contract pursuant to Rider 675 and is consistent with MISO's resource adequacy construct (Module E-1). NIPSCO currently uses, and plans to continue to use, its generation and demand-side assets in its Local Resource Zone to meet its projected peak and reserve requirement. MISO assigned Unforced Capacity ("UCAP") to this DLC resource noted, which is converted to Zonal Resource Credits. On page 32 of the Draft Report, the

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Commission staff asks whether NIPSCO intends 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.

The specific issues and concerns enumerated on pages 27 – 29 of the Draft Report are addressed in the Appendix, Requests 1-8 through 1-23.

IV. Consideration of DSM

The specific issues and concerns enumerated on pages 30-31 of the Draft Report are addressed in the Appendix, Requests 1-24 through 1-34. These responses also address the assertion that there was a difference between the screened measures evaluated in the IRP and those identified as achievable in the DSM Study. NIPSCO's 2014 IRP indicates that for 2014 only, Core and Core Plus programs were implemented. Similarly, the 2014 IRP also indicates that the proposed DSM programs that were filed in early June 2014 for implementation in 2015 only, were implemented assuming Commission approval as filed. As stated on Page 51 of the IRP, in the DSM Study NIPSCO identified the DSM measures that would be appropriate for the NIPSCO territory for 2016-2035. A further explanation is provided in the Appendix, Requests 1-25, 1-26 and 1-28.

The Draft Report states "[i]n general, NIPSCO's 2014 IRP does not provide a very good explanation about the methodology used to identify and integrate DSM programs in the resource planning process." For a thorough explanation of the methodology used to identify and integrate DSM programs in the resource planning process, NIPSCO brings together the information provided in Sections 5 and 9 below.

NIPSCO engaged Applied Energy Group ("AEG") to identify the DSM measures that would be appropriate for the NIPSCO territory.

NIPSCO 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

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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 aeroderivative 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.

V. Resources

The Draft Report notes that ideally, some scenarios and sensitivities involving self-build options would be "co-optimized" with DSM, DR, customer-owned generation and other resources, including transmission. The Draft Report also questioned whether NIPSCO's resource planning model has the capability to consider the reliability of a resource at the time of peak demand, its use for ancillary services and its ability to reduce congestion and marginal losses. NIPSCO's planning tools optimize to net present value revenue requirements and have the capability to "co-optimize" self-build options with DSM, DR, customer-owned generation and other resources, including transmission. Furthermore, NIPSCO's planning tools consider the impact, at peak, of the coincident reduction of load due to DSM and DR options. Credit is given to DSM and DR for their coincident demand reduction, as well as avoided reserves.

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VI. Customer-Owned and Distributed Generation

The Draft Report begins this section by stating that customer-owned and other distributed generation is composed of Net Metering participants and Feed-In-Tariff customers. This statement is incorrect. 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. A response to the question whether NIPSCO plans to offer Time of Use Rates is provided in the Appendix, Request 1-38.

VII. Stakeholder Process

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. As with any decision regarding the IRP process, one should weigh the costs and benefits of any prescriptive requirements for additional stakeholder meetings. Responses to the issues and concerns delineated on page 34 of the Draft Report are addressed in the Appendix, Requests 1-40 through 1-42.

VIII. Conclusion

NIPSCO hopes the clarifications provided in this response alleviate any concerns or confusion that the Commission staff may have had. NIPSCO is always available to meet with the Commission staff for further discussion on its IRP. In fact, as part of its public advisory process that was implemented in 2014, NIPSCO established a continued on-going communications process with all stakeholders. NIPSCO appreciated the participation of its stakeholder group, including IURC staff, in its IRP public advisory process. NIPSCO will look to incorporate these lessons learned into the next public advisory process. With this said, there are some fundamental concerns with the comments in the Draft Report that need to be addressed and resolved for there to be a productive, efficient and effective process for the next IRP filing. It is NIPSCO's hope that these responses will help provide further clarity regarding its 2014 IRP filing, and serve as a starting point for further informal discussions to support the next IRP filing.

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Appendix

Response of Northern Indiana Public Service Company to Draft Report

Request 1-1:
Ideally, alternative plans would be constructed through the modeling of each scenario to develop the corresponding optimal resource plan. Based on sensitivity results shown on page 121, it seems that no alternative analysis was conducted for the "Aggressive Environmental Regulations" scenario. Thus, no optimal plan was developed based on the assumptions in this scenario. Instead, NIPSCO only tested the three lowest cost plans developed under Base Case Assumptions[1] *(or reference case)* using the assumptions in the "Aggressive Environmental Regulations" scenario.
Response:
Aggressive Regulation referenced on pages 120 and 121 is a sensitivity and not a scenario. Aggressive Regulation is a sensitivity analysis on the Slow Economic Improvement Scenario (Base Case). The aggressive regulation sensitivity assumes stricter EPA guidelines for CCR rules, ELG, and Cooling Water Intake rules ("316b"). Under the aggressive regulation; CCR regulatory costs are 34 percent higher, ELG regulatory costs are 159 percent higher, and 316b regulatory costs are 45 percent higher. NIPSCO's Integrated Resource Plan ("IRP") included two scenarios and multiple sensitivities based on those scenarios. NIPSCO utilized the Slow Economic Improvement Scenario as its Base Case and also did an Aggressive Environmental Scenario. The optimal plan developed as a result of the optimization based on the assumptions in the "Aggressive Environmental" scenario is reported in Confidential Appendix J on page 7,346. The optimal Plan 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.

[1] The Business as Usual Case (a/k/a Base Case or Reference Case) might be regarded as the status quo case that includes only known events and expected trends (e.g., forecasts of fuel prices, economic forecasts, capital costs). The BAU should describe what the utility (hopefully 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. That is, it should not include a *preferred portfolio* of resources beyond those with a very high probability of being implemented. The narrative for the base case should also discuss the anticipated uncertainties that would be addressed in scenarios and sensitivities. A BAU should probably not include federal or state legislative or regulatory changes that are not certain or, subject to the utility and stakeholders' opinions, have a very high probability. At the time of the 2014 IRPs, for example, it might have been reasonable for the BAU to not include the Clean Power Plan rules for carbon dioxide. For the 2013-2104 IRPs, the utility and its stakeholders might (or might not) wish to continue existing policies, such as DSM, renewable portfolio standards, or investment tax credits for renewable energy projects, beyond their statutory expiration / sunset date. Any generation or other resources, beyond those that are certain or almost certain – say over the next three years or so - should be added by the capacity expansion planning model to satisfy reliability constraints rather than *hard-wiring* specific types of units at any specific time. Care should be taken to avoid a bias resulting from unusual or cyclical events such as extrapolating that either an economic downturn or extraordinary inflation is expected for the entire planning horizon.

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Request 1-2:

None of the three tested plans are optimal under the Aggressive Environmental scenario. Moreover, none of these three plans were subjected to any stress testing. In essence, because of the structure of the scenario and the lack of an optimal plan produced by the Aggressive Environmental Scenario, NIPSCO only developed a Base Case with different sensitivities.

Response:

The last three cases in Table 9-13 include Aggressive Regulation (sensitivity on Slow Economic Improvement Scenario), Aggressive Environmental Scenario, and the Slow Economic Improvement Scenario (base case). Both the Aggressive Regulation sensitivity and Aggressive Environmental Scenario are included on Table 9-13 to illustrate the projected impact of varying degrees of potential environmental regulation.

The optimal plan developed as a result of the optimization based on the assumptions in the "Aggressive Environmental" scenario is reported in Confidential Appendix J on page 7,346. The optimal Plan 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.

The sensitivities conducted on the Aggressive Environmental Scenario are summarized at the bottom of page 634 of Appendix E. High load growth, low load growth, Synapse Carbon Forecast and solar resource additions sensitivities were included.

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Request 1-3:
Commission staff does not believe that NIPSCO's methodology of comparing a so-called alternative scenario, which Commission staff believes are really sensitivities, to a base case (or reference case) can credibly assess the potential extent of the diverse array of risks that NIPSCO may address over the next 20 (or more) years. Moreover, in the opinion of the Commission staff, the second scenario (the Aggressive Environmental) isn't really a scenario at all. The Commission staff believes that each scenario should result in a separate optimized resource plan. Instead, NIPSCO treated the Aggressive Environmental as a sensitivity to the base plan. The Commission staff believes NIPSCO's approach is at variance with, what we believe to be, common utility practice.
Response:
As discussed previously, NIPSCO developed two scenarios and various sensitivities. While it may have been unclear in NIPSCO's IRP, the Aggressive Environmental Scenario includes an optimized resource plan. Please see Confidential Appendix J, where NIPSCO provided the optimal plans both scenarios. For additional information, please see the responses to Request 1-1 and Request 1-2.

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Request 1-4:
While this is NIPSCO's IRP, input from stakeholders during the selection of scenarios and sensitivities might have assisted NIPSCO's planners. Would NIPSCO be amenable to including stakeholders in the formulation of the BAU, scenarios, and sensitivities for the next IRP?
Response:
NIPSCO is amendable to continuing discussions with stakeholders regarding the formulation of additional scenarios and sensitivities and subsequently modeling relevant scenarios and sensitivities. As part of the 2014 public advisory process, NIPSCO offered stakeholders the opportunity to formulate scenarios and sensitivities. NIPSCO modeled numerous scenarios and sensitivities and conducted supplemental analyses as requested by stakeholders as included in Appendix E pages 473 through 592.

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Request 1-5:
NIPSCO (page 96) *At this time, it does not appear likely that widespread GHG [Green House Gas] reductions will be required until, at a minimum, the latter half of this decade. NIPSCO is economic and political environment, in addition to the time required for a widespread program to be developed and implemented.* The Commission staff understands the proposed draft rules for the EPA's Clean Power Plan was issued in June 2014 which was after NIPSCO and other utilities were well underway with their IRP process. For this reason, the Commission staff did not expect an in-depth analysis of the potential ramifications because the price of carbon dioxide and the mitigation plans were not known. However, the Commission staff believes it would have been reasonable to expect scenarios and sensitivities with different prices for CO2. Also, given the significant risks, the Commission staff would expect that NIPSCO might want to do *what ifs* for implementation dates before 2025. Even if 2025 is a reasonable date for CO2 prices to be established, that is still well within the 20 year planning horizon that NIPSCO should be evaluating. Such a scenario and sensitivities would have enabled NIPSCO to conduct at least a preliminary assessment of potential risks of CO2.
Response:
Analysis conducted for NIPSCO's 2014 IRP included various carbon cost and timing sensitivities; please see NIPSCO's IRP Section 9 pages 119-120 as well as Appendix E pages 329, 520, 531, 553, 555, 568, and 634 for carbon price implementation in 2020, carbon breakpoints, high carbon price sensitivity, and Synapse carbon price sensitivity and no carbon sensitivity. In addition, EPA included in its proposed Clean Power Plan ("CPP") additional renewable energy and energy efficiency. NIPSCO's Aggressive Environmental Scenario included a 15% renewable portfolio standard. Coupled with the carbon pricing utilized in its various sensitivities, NIPSCO's analysis includes a scenario that is reflective of or more stringent than the proposed CCP

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Request 1-6:
During the stakeholder meetings, NIPSCO expressed concern that a very high carbon price may cause some industrial customers to leave. However, this concern, then, should be reflected in scenarios and sensitivities that objectively assess this risk. With the prospect for relatively low natural gas prices, is there a potential for some industrial customers to switch some of their electric use to natural gas? If the potential for reduced electric use wasn't given explicit consideration, can NIPSCO offer a rationale?
Response:
Large industrial customers are constantly considering more efficient ways to perform processes and produce products. NIPSCO works with those customers on an on-going basis to better understand these potential changes, and, through its energy efficiency program, assist customers in becoming more efficient. There is the potential that some industrial customers could switch some of their electric use to natural gas. However, at this time, NIPSCO is not aware of any large electrically driven equipment that might move to natural gas as an alternative to electric. One customer has a combustion turbine as a prime mover that could be operated on natural gas, but has not indicated a desire to switch to natural gas at this point. Therefore, NIPSCO factored in reduced electric use by large industrial customers through energy efficiency projects, rather than assuming movement to natural gas. As part of its on-going dialog with its large industrial customers, NIPSCO will continue to assess the possibility for reduced electric consumption based on a switch to natural gas.

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Request 1-7:
NIPSCO should give consideration to incorporating more probabilistic analysis into the IRP. From the perspective of the Commission staff, probabilistic analysis is likely to be more objective and comprehensive than deterministic approaches because probability analysis can assess the frequency, duration, and severity of events. For this reason, probabilistic analysis may provide an additional perspective for benefit – cost analysis of a variety of resource options which, in turn, provides a more comprehensive and insightful narrative. For example, probabilistic analysis of lower probability but high consequence events such as the "polar vortex" may provide a more useful narrative because deterministic methods may overstate the concern and lead to unnecessary and costly responses. Probabilistic methods may also provide more insight into the contribution of renewable resources, distributed generation, demand response, and energy efficiency since deterministic methods often look at pre-determined contributions of these resources to the summer (or winter) peak demands. Since NERC is also considering incorporating more probabilistic analysis in their assessments as a complement to deterministic methods, this may add to the rationale for greater use of probabilistic method in IRPs. For the IRP process, explaining outcomes in a probabilistic context may aid stakeholder understanding because it addresses frequency, duration, and severity. In contrast, solely using deterministic analysis of a worst case scenario may appear to be unnecessarily bleak because it lacks parameters of frequency, duration, and severity. Probabilistic analysis better reflects the reality that multiple things simultaneously are always changing and many factors are moving in opposite directions. For example, commodity prices might have a general increasing trend (or not) over a period of time but they will fluctuate, sometimes extensively, around the trend.
Response:
NIPSCO will take the recommendation under consideration, but regarding decisions related to the planning tools, process and databases, one needs to weigh the benefits of such additions with the costs to customers and whether a construction decision is being made. Additional dialog on this topic might be appropriate as part of the annual Contemporary Issues Meeting.

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Request 1-8:
What base temperature is used for cooling degree days ("CDD") and heating degree days ("HDD")?
Response:
The base temperature used for CDD and HDD is 65 degrees Fahrenheit.

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Request 1-9:
NIPSCO uses the 1976 -2010 average for both cooling degree days ("CDD") and heating degree days ("HDD") as normal weather. Is this truly a simple average or is it a true normal? Why use 35 years? This 35 year period seems unusually long and the National Oceanic and Atmospheric Administration's ("NOAA's") official "normals" are based on 30 years. NIPSCO might wish to consider going to even shorter periods to better account for warming trends.
Response:
The CDD and HDD are simple averages calculated for each day of the year. The 35 year definition was selected by NiSource management as a planning standard for all of its distribution companies.

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<u>Request 1-10:</u>
Do we understand correctly that the weather normalization procedure uses regression models of 10 years of monthly kWh / customer / day on cooling degree days ("CDD") / day and heating degree days ("HDD") / day plus additional terms for some month CDDs and a trend variable as deemed appropriate? If our understanding is correct, what does "additional terms for some month CDDs" mean and how does it affect the model?
Response:
Your understanding is correct. In the residential regression CDD/day is entered as an independent variable or term for the summer months May-October. This original specification yields a coefficient or measurement of the seasonal CDD/day effect. An additional independent variable is entered for May where May = May CDD/day and all other summer months equal zero. This additional term has a negative coefficient with an absolute value less than the seasonal CDD/day coefficient and adjusts the CDD/day effect in a month where the weather effect is smaller than the weather effect for the unadjusted months. Similar terms are used for June and October CDD/day. A similar term also is used for May HDD/day where the seasonal independent variable, HDD/day is defined for the months October-May. These additional terms are not significant in the commercial regression and therefore are not used.

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Request 1-11:
Heating Degree Days ("HDD") was not a driver in the commercial forecast model. Did NIPSCO make an attempt to include it? If so, please detail the effort. If no attempt was made to include HDD, please explain the rationale.
Response:
NIPSCO did not include HDD in the commercial forecast model because, during the 2014 model update, the HDD variable was shown to be not statistically significant and was not included. All forecast models are updated on an annual basis. Many different independent variables and specifications are considered. Models that do not comport with statistical tests, including not being significant, or that yield unreasonable results are eliminated. During the year, variance analysis is completed to validate the model's performance. In previous models, HDD was included as an independent variable because it was shown to be significant.

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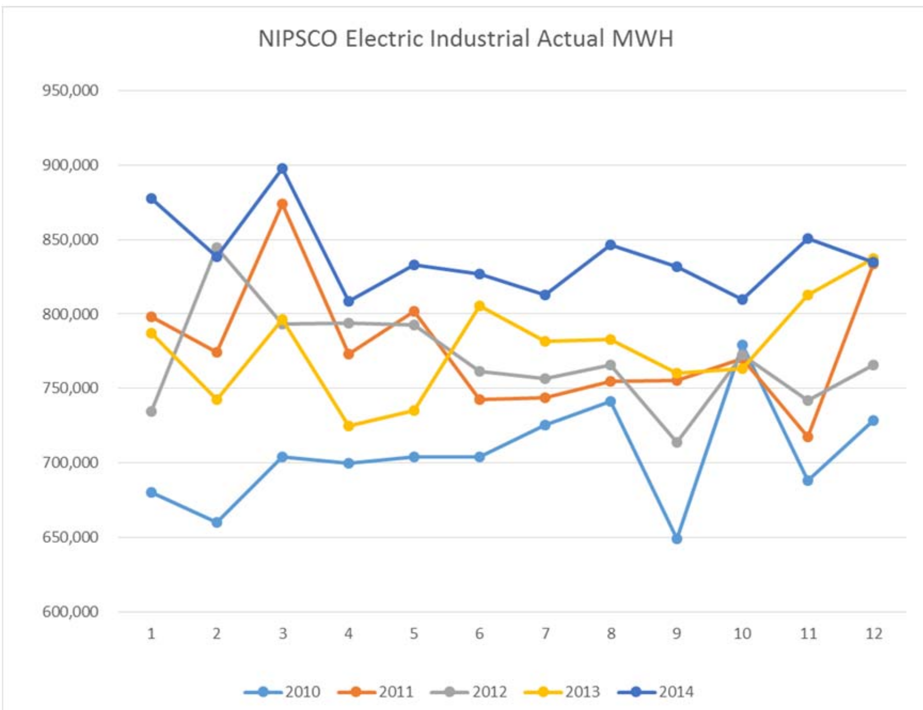
Request 1-12:

NIPSCO produces weather normalized historical energy for residential and commercial customers only. NIPSCO does not produce one for industrial customers because, according to NIPSCO, *"industrial varies very little with weather."* While this may be correct, the Commission staff would like to know if NIPSCO has done an objective analysis of whether industrial loads are affected by temperature and humidity. The Commission staff would be surprised if there was no affect. Regardless, for credibility, the Commission staff believes it would be appropriate to weather normalize.

Response:

While NIPSCO has not done an analysis regarding the impact of temperature and humidity on industrial load, the accompanying graph shows the monthly industrial load for 2010-2014. With no compelling seasonal pattern, NIPSCO does not normalize this load.



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<u>Request 1-13:</u>
The long-term Residential forecast uses historical and forecast saturations and efficiencies from Itron and the United States Energy Information Agency ("EIA"). Was the Itron – IEA data tailored to NIPSCO? Has NIPSCO conducted a statistically valid independent analysis to verify the data?
<u>Response:</u>
NIPSCO incorporates the level of its residential customer's air conditioning saturation into the Itron regional information that is used in the residential forecast. No independent analysis has been conducted to verify the Itron-EIA supplied data.

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Request 1-14:
The Residential forecast is a multiplication of the number of projected customers times residential use per customer. Customer count is also listed as a driver in the use per customer model. This is confusing and the Commission staff is concerned about the appropriateness of this. Could NIPSCO please explain?
Response:
"Other forecast considerations integrated into the residential forecast model include residential customer counts. . ." (Section 4, pages 18-19) referred to the multiplication of customers and kWh/customer. It was not meant to imply that customer count was an independent variable in the energy model. In forecasting residential load, NIPSCO uses "residential KWH per customer" model, which is a function of real residential electric price, real per capita income, saturations and efficiencies utilizing the Itron index for the East North Central region, cooling degree days ("CDD") and heating degree days ("HDD"). The "residential KWH per customer" forecast is multiplied by the residential customer forecast to obtain KWH.

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Request 1-15:

Both the longer-term Residential and the Commercial forecasts are partially a function of the historical customer attrition rate. This assumes that historic attrition rates will continue into the future. Especially since we experienced a recession and slow economic growth for a few years, is this reasonable? Has NIPSCO conducted any analysis of whether this driver is stable? If so, over what period was it stable? More discussion of the rationale would be helpful.

Response:

The residential forecast uses the attrition assumption while the commercial forecast uses it only as a check for reasonableness. The accompanying table shows that residential attrition has been stable for the past five years. The average for 2010-2013 was selected for use in the forecast because of the stability in recent years and the fact that it is close to the longer term average.

Res		Customers				
		Year End	Additions	Attrition	% Additions	% Attrition
NIPSCO Elec	2005	395,849				
NIPSCO Elec	2006	398,349	5,951	(3,451)	1.5%	-0.9%
NIPSCO Elec	2007	400,991	4,429	(1,787)	1.1%	-0.4%
NIPSCO Elec	2008	400,640	3,290	(3,641)	0.8%	-0.9%
NIPSCO Elec	2009	400,016	2,321	(2,945)	0.6%	-0.7%
NIPSCO Elec	2010	400,522	2,068	(1,562)	0.5%	-0.4%
NIPSCO Elec	2011	400,567	1,890	(1,845)	0.5%	-0.5%
NIPSCO Elec	2012	401,176	2,083	(1,474)	0.5%	-0.4%
NIPSCO Elec	2013	402,638	2,539	(1,077)	0.6%	-0.3%
NIPSCO Elec	2014	403,270	2,359	(1,727)	0.6%	-0.4%
	Sum		26,930	(19,509)		
	Average		2,992	(2,168)	0.7%	-0.5%
	Average 2010-2013					-0.4%

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Request 1-16:
NIPSCO correctly notes that the Commercial class is a very diverse rate class which would seem to provide even more compelling reason to develop homogenous sub-groupings by North American Industry Classification System ("NAICS") or Standard Industrial Classification Codes ("SIC Code"), usage, and other groupings. Would NIPSCO agree that sub-groups might increase the explanatory value of the load forecasts, improve the credibility, and provide better insights regarding DSM, DR, and customer-owned generation?
Response:
No, NIPSCO does not view NAICS or SIC Code data to be necessary to improve load forecast. As the tables on page 27 indicate, NIPSCO has a good track record around its forecasts. Because there has not been a concerted effort to obtain and confirm these codes, about 20% of the commercial class kilowatt hours are unassigned to SIC Codes and the other 80% assignment is of unknown quality. Therefore, there is no reason to presume that sub-groups would materially affect the level of the commercial forecast. The demand side management ("DSM") forecast is handled through the creation of a market potential study ("MPS") and updates to that MPS, including the DSM forecast created in developing NIPSCO's Integrated Resource Plan. As such, the forecast is handled in a way that is most appropriate to determine DSM potential. In terms of whether the SIC codes would provide any additional insights regarding DR or customer owned generation, NIPSCO currently has a tariff that offers customers the opportunity to participate in a Demand Response program. If there were to be any commercial customer interest in the program, this would be a much better indicator of the future potential of DR and customer owned generation and would provide greater insight into potential load effects than simply sub-grouping data by SIC codes.

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Request 1-17:
NIPSCO's projection that the number of industrial customers and their demand will be constant throughout the entire forecast horizon strains credulity. What is the narrative to justify this? At a minimum, the Commission staff believes this is inconsistent with historical information. It also seems to ignore the potential for these customers to generate their own power (e.g., CHP), to participate in Demand Response (which was also projected to be flat), or to install equipment that uses less electricity; especially with relatively low price projections for natural gas and the potential for major changes in NIPSCO's and the region's generating fleet. Given that industrial load is about half of NIPSCO's total load it is a huge assumption that the number of customers and their demand will be flat which has significant consequences. With this huge uncertainty, it is surprising there are no scenarios (and only single sensitivity) with higher/lower load growth.
Response:
NIPSCO's projection that the number of industrial customers and their demand will be constant throughout the entire forecast horizon is derived from conversations with its largest customers. Given the uncertainty over many of their variable cost inputs to their manufacturing process, it becomes very difficult for NIPSCO to forecast the long term customer volume and demand with any certainty beyond the first two years. An example of this is recent strength of the dollar, which has led to a wave of imported steel in the United States from foreign countries at prices below domestically produced steel. Therefore, there is no better way to forecast over a 20-year horizon than to assume the demand remains constant. As for combined heat and power ("CHP") and demand response, in communications with NIPSCO's largest customers, it is apparent that there are no plans on the part of those customers to increase either in the short term. NIPSCO's industrial load has traditionally used CHP as a means to generate steam with electricity as a byproduct. Until the installed CHP reaches the end of its useful life or more steaming capacity is needed there is no real driver to increase its use. NIPSCO has a demand response program (Riders 681 and 682), and there is currently one eligible customer participating in Rider 681 DRR-1, whose first offer was received March 25, 2015, with implementation on March 27, 2015. NIPSCO does have participation in its interruptible tariff, but is currently limited to 377 MW, which is fully subscribed. Based on these factors, it was determined that constant industrial demand was appropriate for the purposes of this IRP.

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Request 1-18:
If the Industrial sector is indeed flat throughout the entire forecast horizon, shouldn't this have ramifications for the commercial and residential classes? How is this integrated into the residential and commercial forecasts? Has NIPSCO considered a transition from informed judgment to an econometric approach? While the Commission staff recognizes the sensitivity, after a couple of years don't customer plans become more available?
Response:
The residential and commercial models rely on economic inputs from the Global Insight regional forecasts using the same concepts as used to develop historical model coefficients. These coefficients represent the drivers for the residential and commercial markets. Industrial output has not been modeled as a driver of residential and commercial consumption, consequently there is not a direct link to the independently generated NIPSCO industrial forecast. NIPSCO's projection that the number of industrial customers and their demand will be constant throughout the entire forecast horizon is derived from conversations with its largest customers. Given the uncertainty over many of their variable cost inputs to their manufacturing process, it becomes very difficult for NIPSCO to forecast the long term customer volume and demand with any certainty beyond the first two years. An example of this is recent strength of the dollar, which has led to a wave of imported steel in the United States from foreign countries at prices below domestically produced steel. Therefore, NIPSCO believes this current methodology is the most accurate way to forecast the large industrials over a 20-year horizon.

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Request 1-19:
It would seem that the industrial and commercial forecasts would have a bearing on the number of residential customers and their incomes but this and other interrelationships are not obvious from the descriptions in the IRP.
Response:
The residential model relies on economic inputs from the Global Insight regional forecasts using the same concepts as used to develop historical model coefficients. These coefficients represent the drivers for the residential market. Any links from industrial and commercial activity are through the Global Insight model.

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Request 1-20:
Street lighting, Public Authority, Railroads, Company Use, and Losses are forecast using current levels and anticipated trends. Has NIPSCO made an effort to use a regression model at least for street lighting (recognizing the increasing use of more efficient lighting as a reason for closer examination) and Public Authority? Other utilities do this.
Response:
The street lighting model utilizes the growth rate from the residential customer forecast model to project future street lighting usage. The public authority model reflects a recent twelve month average. Collectively, street lighting and public authority make up about 0.5% of NIPSCO's total volumes on an annual basis. NIPSCO has not explored regression modeling for these minor categories. Regarding decisions related to the planning tools, process and databases, one needs to weigh the benefits of such additions with the costs to customers.

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Request 1-21:
Forecast bands are calculated with underlying model predicted values along with a statistically estimated 95% confidence interval around those values. High includes GWh sales reflecting industrial expansions currently being developed in NIPSCO's service territory. It's not clear to Commission staff how this is done. Is this *on top* of the 95% band? Is the low band purely statistical while the high band includes (or entirely) informed judgment?
Response:
Both the high and low residential and commercial sales are estimated using the 95% confidence bands from the models. Nothing is added *on top* of the 95% confidence intervals for residential and commercial. The industrial high and low energy scenarios are added to the residential and commercial energy scenarios to generate the high and low total energy forecast. The industrial forecast does not use the confidence interval concept.

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Request 1-22:
An on-going concern for NIPSCO and all utilities is the continual enhancements to the databases to support state-of-the-art load forecasting. For discussion purposes, the forecast captures the "average" customer but, aside from simplicity which has merit, would there be advantages to stratifying by usage or other groupings to provide greater intra-class information? That is, by constructing sub-groups wouldn't the explanatory value of the forecast improve? Wouldn't this information be helpful in assessing the potential for DSM, DR, and customer-owned generation as well as the design of rates?
Response:
Please see the response to Request 1-16. In addition, regarding decisions related to the planning tools, process and databases, one needs to weigh the benefits of such additions with the costs to customers.

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Request 1-23:
Why is the high, low, and most expected load forecasts included in the confidential information?
Response:
Including the high, low and most expected load forecasts in the confidential information is an oversight on NIPSCO's part. NIPSCO will include the forecasts into non-confidential appendices going forward.

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Request 1-24:
In general, NIPSCO's 2014 IRP does not provide a very good explanation about the methodology used to identify and integrate DSM programs in the resource planning process. The Commission staff would welcome NIPSCO's response to the Commission staff's concern that DSM seems to have been *baked into* the IRP and merely been layered on-top of NIPSCO's preferred resource plans rather than being truly integrated into the planning process. The constant demand reductions for the Industrial class add to our concern. If the Commission staff's understanding is correct, this is very concerning since the IRP intends that DSM compete with other resources for inclusion in the IRP on as comparable a basis as possible.[2]
Response:
Although possibly unclear in the narrative, NIPSCO's DSM was not "baked into the IRP" and merely been "layered on-top of NIPSCO's preferred resource plans rather than being truly integrated into the planning process." NIPSCO allowed the IRP model to select demand-side resources on a comparable basis to supply-side resources. The description of the demand-side resources considered and input into the model, are listed in Section 7, page 86. They are identified as Commercial Heating, Ventilation and Air Conditioning ("HVAC"), Commercial Lighting, Commercial Process, Commercial Other, Residential HVAC, Residential Lighting, Residential Other, Residential Air Conditioning ("AC") Cycling and Industrial Direct Load Control. These demand-side resources, along with supply-side resources were evaluated on a consistent and comparable basis. Not all were selected by the model. In Section 9, page 111, NIPSCO describes the resource optimization analysis that considered these demand-side options on an equal footing with supply-side options. The DSM resources selected were Commercial Lighting, Commercial Other, Commercial Process, Residential Lighting, and the Residential AC Cycling. The DSM resources rejected were Commercial HVAC, Residential HVAC and Residential Other. The resulting plan with the selected demand-side resources demonstrated a net present value revenue requirement ("NPVRR") of $11,304,097 (2013 K$); the expansion plan is defined in Table 9-5. The inclusion of the demand-side resources in the portfolio effectively eliminated the need for external market capacity purchases. The inclusion of DSM programs resulted in an overall NPVRR savings of $325,564 (2013 K$). NIPSCO, then, did allow for DSM to compete with other resources for inclusion in the IRP on a comparable basis.

[2] The Commission staff appreciates the difficulty of comparable treatment of DSM with utility generation. This problem MAY be ameliorated by the use of next generation long-term resource planning tools that co-optimize DSM with traditional generation resources and, purportedly, are capable of utilizing more discrete time intervals to better capture DSM and the operations of generating resources on a comparable basis. The Commission staff suggests that NIPSCO may wish to consider these tools that have more granular information and rely more heavily on probabilistic analysis rather than deterministic analysis. These tools need not be considered as a replacement, at least initially, but as providing another perspective.

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Request 1-25:

It's unclear how the eligible customers for some of the proposed 2015 DSM programs were selected. Furthermore, there is no information related to the number of participants in each program and how they were projected into the future. Given that the forecast has variables for number of customers and their usage, this seems to be inconsistent treatment.

Response:

a. Selection of eligible customers for 2015 programs: When planning for the 2015 DSM Programs, NIPSCO assumed that all Rate 632, 633, 634 and 644 customers would opt out. All other customers were assumed to be eligible for the programs in the appropriate class (i.e. residential customers were not assumed to be eligible for commercial and industrial programs).

b. Number of participants in each program for 2015 programs: The table below shows the projected number of participants per program for 2015:

Participants per Program (Net)	
Program Name	2015
C&I Prescriptive Program	112,356
C&I Custom Program	45
C&I Small Business Direct Install	45,732
C&I School Audits	281
Residential Weatherization Program	49,868
Residential Energy Awareness Program	239,500
Residential Low Income Weatherization	541,664
Residential New Construction	664
Residential Prescriptive Electric	3,570
Residential Elementary Education Program	105,865
Residential Lighting Program	255,953
Air Conditioner Cycling Program	33,000

c. Projection of participants in each program into the future: In order to forecast participant rates in the future, AEG developed market adoption rates for each measure that specify the percentage of customers that will select the efficient, economic measure or option when faced with the opportunity. AEG then used a variety of secondary sources, as well as past program history from NIPSCO to refine these participation rates. The secondary sources include other studies that AEG had completed for other utility clients and the purchasing trends indicated in the United States Department of Energy's 2013 Annual Energy Outlook.

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Request 1-26:

There is a vague explanation as to how the 2014 and 2015 programs were selected. It's not clear that they were subjected to a screening process or benefit cost test. Could NIPSCO please clarify?

Response:

Yes, NIPSCO's demand side management (DSM) programs are always subject to benefit cost test screening. In putting together its 2014 program, which was based on meeting the goals established by the Commission in the Phase II Order of Cause No. 42693 issued on December 9, 2009, NIPSCO completed an update to its Action Plan and filed that Action Plan in Cause No. 44363. In 2015, NIPSCO used the same Action Plan to inform its program selection and conducted updated benefit costs tests on the proposed program offerings, which were approved by the Commission in Cause No. 44496. The chart below, from an exhibit attached to Karl Stanley's testimony in Cause No. 44496, provides the benefit cost test results for each of NIPSCO's programs offered in 2015.

Benefit Cost Analysis					
NIPSCO DSM Electric Programs					
Program Name	Utility Test	TRC Test	RIM Test	Societal Test	Participant Test
C&I Prescriptive Program	4.49	3.88	0.65	4.61	5.50
C&I Custom Program	5.09	2.06	0.71	2.59	2.25
C&I Small Business Direct Install Program	1.71	1.65	0.53	1.99	3.45
School Audit Direct Install Program	1.63	1.73	0.49	1.93	4.72
Residential Home Energy Audit and Weatherization Program	1.58	1.52	0.64	2.01	8.62
Residential Home Energy Conservation Program	3.37	3.37	0.77	3.37	NA
Residential Low Income Weatherization Program	1.44	1.44	0.62	2.13	NA
Residential New Construction Program	1.69	0.99	0.73	1.35	1.02
Residential Energy Efficiency Rebate Program	3.06	1.82	0.80	2.34	1.80
Residential Elementary Education Program	1.71	1.71	0.54	2.01	NA
Residential Lighting Program	3.23	2.56	0.61	2.82	5.37
Air Conditioner Cycling Program (Residential and C&I)	0.58	2.65	0.57	2.65	NA
NIPSCO DSM Electric C&I Portfolio	3.94	2.66	0.67	3.24	3.57
NIPSCO DSM Electric Residential Portfolio	1.69	1.71	0.63	2.05	5.31
NIPSCO DSM Electric Portfolio	2.76	2.34	0.64	2.81	4.28

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Request 1-27:
How were the projected annual costs of each DSM measure calculated? There is no explanation on how these costs were determined. Furthermore, there is a need for calculation on how the projected escalation factor adjustment used in the avoided cost calculation was achieved.
Response:
a) Annual Cost Projections NIPSCO utilized AEG to perform its demand side management (DSM) forecast for inclusion in the Integrated Resource Plan. In determining the projected annual cost for each DSM measure, AEG used NIPSCO and Indiana-specific measure data, if available, first and, when such information was not available, relied on the extensive Database of Energy Efficiency Measures ("DEEM") maintained by AEG engineering staff as well as planning studies conducted by AEG for use by other utilities around the country. In order to remove inflationary effects, AEG's analysis was conducted in terms of real dollars in the base year (2013). Therefore, once the appropriate cost input is ascertained for the base year of the study, the majority of costs remain unchanged for the entire study time horizon. For measures with quickly evolving costs trends, the analysis was adjusted accordingly. This included all varieties of light emitting diode ("LED") or solid-state lighting, which was predicted to drop in cost by more than 50% over the course of the study according to the Department of Energy's 2013 Annual Energy Outlook. b) Projected Escalation Factor Adjustment in the Avoided Cost Calculation The projected escalation factor adjustment used in the avoided cost calculation is a combination of the New York Mercantile Exchange ("NYMEX") forecasts and PIRA's locational market prices ("LMPs") coupled with the Consumer Price Index issued by the United States Department of Labor's Bureau of Labor Statistics ("CPI"), which is used to assess price changes associated with the cost of living, from the September 2013 Global Insights Database. The NYMEX information and the PIRA information were inflated by the CPI (which is the measure of weighted average prices of a basket of consumer goods and services).

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Request 1-28:
Again, while assuming no large customer opt out has some potential benefits, this decision could have significant implications for the projected energy savings and avoided costs of the programs (page 52). Furthermore, this assumption is inconsistent with the Commission staff's understanding of the development of a Base Case (a/k/a Business as Usual or Reference Case). Since the Senate Enrolled Act 340 which allows large customers to opt out was passed during the development of the IRP and since this legislation was supported by large customers, continuing to include them seems unduly optimistic. Did NIPSCO also assume that large commercial customers would also opt out?
Response:
NIPSCO anticipated there would be some large Commercial customers that would opt out, but did not include those customers in its analysis. As discussed in Karl Stanley's testimony in Cause No. 44496, NIPSCO assumed that its largest 16 eligible customers by demand at a single site as well as the customer on Rate 644, for a total of 17 customers, none considered commercial, would opt out of the DSM program prior to January 2015. This is equal to 54% of NIPSCO's total C&I load.

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Request 1-29:

AEG reported results (Appendix G) that left the Commission staff unclear as to what is included in the baseline forecast. Moreover, the graphs show that "NIPSCO with DSM" projection is above the baseline forecast in the Commercial and Industrial sectors (page 30) but this projection twice crosses the baseline in the Residential sector scenario. What is the rationale for this outcome?

Response:

Although it aligns closely, the baseline projection AEG used for its forecast is not the same as NIPSCO's official load forecast. The reason AEG did not use NIPSCO's load forecast is because the savings from past programs and the projected savings from future programs are embedded in the NIPSCO forecast. The AEG baseline projection, however, assumes that there are no future DSM programs. AEG developed the baseline projection to serve as the metric against which the technical, economic, achievable, and program potentials are measured for each demand side management (DSM) program. The DSM forecast results only consider the energy consumption and savings in terms of the AEG baseline projection.

The baseline projection of annual electricity use and summer peak demand for 2013 through 2035 by customer segment and end use without new utility programs was developed by using relatively certain impacts of codes and standards that were defined as of December 2013 and will unfold over the forecast timeframe. The baseline projection is the foundation for the analysis of savings from future energy efficiency efforts as well as the metric against which potential savings are measured.

Inputs incorporated into the baseline projection include:

- Current economic growth forecasts (i.e., customer growth, income growth)
- Electricity price forecasts
- Trends in fuel shares and equipment saturations
- Existing and approved changes to building codes and equipment standards
- Naturally occurring efficiency improvements, which include purchases of high-efficiency equipment options by early adopters.

AEG also developed a baseline projection for summer and winter peak by applying the peak fractions from the energy market profiles to the annual energy forecast in each year.

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Request 1-30:
Were free riders considered in the DSM modeling process? The Commission staff couldn't find any information.
Response:
Yes, NIPSCO DSM did consider freeridership in the modeling process. Freeridership is used in calculating the net savings values. "Net savings" refers to savings directly attributable to a program and represent the savings that are directly attributable to the program's efforts (this is also known as the net-to-gross value). Net savings are determined by adjusting the evaluated gross savings estimates to account for a variety of circumstances, including savings weighted free rider effects and market effects. For purposes of the modeling process, NIPSCO used the formula Net-to-Gross Ratio = (1- freerider adjustment).

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Request 1-31:
According to NIPSCO, DSM had negligible effects on T&D requirements. From the Commission staff's perspective, while we have no reason to doubt NIPSCO's assessment, we hope that NIPSCO will periodically assess the avoided T&D costs especially as the quantity and quality of information from Smart Grid and AMI becomes more available.
Response:
NIPSCO does not have any residential advanced metering infrastructure ("AMI") deployed, nor does it plan such a deployment in the foreseeable future. However, NIPSCO will continue to review (i) other industry-related Smart Grid and AMI information as well as (ii) whether energy efficiency programs have any noticeable impact on the demand or capacity needs of customers, which is the driver for fixed cost investments, such as transmission and distribution costs.

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Request 1-32:
NIPSCO affirmed potential benefits for inclusion of 122.9 MW incremental Industrial DLC (NIPSCO described the parameters as: curtailment and short notice interruptions with at least ten minutes notice. Curtailments were assumed to be unlimited in quantity and duration, and limited to no more than one interruption per day, no more than 12 consecutive hours, no more than three consecutive days during week days, and no more than 200 hours per rolling 365 days). Page 116 Has NIPSCO considered the conditions under which additional DLC might be procured?
Response:
Increasing the level of interruptible service under Rider 675 (Option D Curtailment and Short Notice Interruptions) was discussed during the June 20, 2014 one-on-one meeting with the Industrial Group and subsequently analyzed in the IRP (see Appendix E, page 516). It is part of NIPSCO's Short Term Action plan to explore the potential for increased interruptible (resources under Option D of Rider 675(page 133). Additional direct load control might be procured through other NIPSCO Riders, including currently approved demand response services under Rider 675, Rider 681, Demand Response Resource (DRR) Type 1 – Energy Only, 682, Emergency Demand Response Resource (EDR) - Energy Only and Rider 684, Credits for Direct Load Control Program). As of March 2015, NIPSCO has entered into an agreement with one customer to participate in Rider 681.

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Request 1-33:
Consistent with a concern the Commission staff raised in the Load Forecasting comments, what is the status of deployment of efficient street lighting within NIPSCO's service territory?
Response:
In its Order in Cause No. 44370, as part of NIPSCO's 7-Year Electric Transmission, Storage and Infrastructure Improvement Charge ("TDSIC") Plan, the Indiana Utility Regulatory Commission ("IURC") approved a municipal street lighting program. This program will replace company-owned, outdated, poorly illuminating, high-pressure sodium ("HPS") street lighting with bright, light-emitting diode ("LED") lights. In collaboration with interested communities, NIPSCO representatives have been evaluating the fixtures available in the industry and have completed trials in three locations. NIPSCO's team worked with a number of different vendors, including visiting their facilities, in order to narrow the choices of potential fixtures. As the pilot progressed, NIPSCO worked with the Indiana Municipal Group, through its expert, Dr. Robert Kramer of Purdue University-Calumet, to assure that the best information possible was collected. This included photometric testing of the trial fixtures and gathering input from customers near the trial locations as well as community leaders. NIPSCO is expecting to issue its LED standards early in the second quarter of 2015, which will include light wattages, patterns, and approved manufacturers. NIPSCO is also performing analysis on the impact of the proposed fixtures on its Street Lighting tariff (Rate 650). As the standards and rates are being finalized, NIPSCO is working on the competitive process to replace its lights in interested communities. NIPSCO expects to issue a request for proposal during the second quarter of 2015 and begin installation during the first quarter of 2016. Because this project is part of the broader Economic Development funds in the TDSIC plan, the number of street lights that NIPSCO will replace through this program will be predicated on the availability of funding. NIPSCO plans to reevaluate its options at the end of the current TDSIC Plan. In addition, NIPSCO is in the planning stages for the eventual phase-out of HPS installations and replacements. Note that these programs address a category of consumption that represents less than 0.4% of total annual KWH.

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Request 1-34:
IPL and I&M is instituting *Conservation Voltage Reduction* (CVR). Has NIPSCO given consideration to a similar effort?
Response:
NIPSCO has not implemented Conservation Voltage Reduction ("CVR"), nor does it plan to in the near future. However, NIPSCO will continue to evaluate this and other technologies to ensure it maintains safe and reliable electric service for its customers now and into the future.

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Request 1-35:

Based on significant customer response to NIPSCO's *Feed-In Tariffs* for renewable energy, the Commission staff would like to know if NIPSCO has done a forecast of the potential for customer-owned and other distributed generation? NIPSCO's three year pilot feed-in-tariff (FIT) to promote customer-owned renewable power was approved by the IURC on July 13, 2011 with a cap of 30 MW (beginning on page 62). There are now 29.7 MW enrolled. NIPSCO's Phase II (Electric Rate 665) has expanded the resources by about 24.7 MW with an additional 16 MW being allocated to smaller renewable energy projects. At present, NIPSCO lists the following resources:

- PV solar generation: 15.50 MW
- Wind generation: 1.98 MW
- Biomass-fueled generation: 21.06 MW

Response:

Please note the resource generation listed above also includes installed renewable energy outside of the feed-in tariff and includes generation facilities that are interconnected with NIPSCO, but the output of which is not purchased by NIPSCO.

The following generation resources NIPSCO currently has active agreements with, or are pending installation are:

	Feed-in Tariff Installed (MW)	Feed-in Tariff Queue (MW)	Net Metering Installed (MW)	Net Metering Queue (MW)	Cogen Rate Installed (MW)	Total Capacity (MW)
Biomass	11.350	3.000	-	-	1.290	**15.640**
Solar	15.195	0.006	0.782	0.073	-	**16.056**
Wind	0.160	-	1.923	0.018	-	**2.101**
Subtotal	**26.705**	**3.006**	**2.705**	**0.091**	**1.290**	**33.797**

In preparation for NIPSCO's stakeholder discussions surrounding the extension of its Feed-in Tariff, which was recently approved by the Commission in Cause No. 44393 ("FIT 2.0"), NIPSCO forecasted the annual energy generation by the customers enrolled in the original FIT program once all of that generation is on-line. The forecast used 2013 actual capacity factors to estimate an expected capacity factor for each technology type to extrapolate an expected energy forecast for each generator.

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The following table shows the forecasted generation (Sum of Forecasted Savings) by technology type.

Technology Type	Generator Size	Forecasted Capacity Factor
Micro Solar	<10 kW	13.4%
Intermediate Solar	>10 kW and < 200 kW	13.8%
Small Wind	<10 kW	13.5%
Intermediate Wind	>10 kW and < 200 kW	20.0%
Large Solar	>200 kW and < 2 MW	17.6%
Biomass	<5 MW	71.4%

Row Labels	Sum of CONNECTED LOAD (kW)	Sum of Forecasted Generation (Kwh/yr)	Customer Count
BIOMASS	14,348	89,741,575	7
SOLAR-LARGE	14,500	22,291,607	15
SOLAR-SMALL	658	771,823	78
WIND-INTERMEDIATE	150	262,800	2
WIND-SMALL	10	12,063	2
Grand Total	**29,666**	**113,079,868**	**104**

NIPSCO has not performed any other forecast of customer-owned and other distributed generation.

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Request 1-36:

NIPSCO states that an additional .19 MW of PV solar, .11 MW of wind generation, and 10.95 MW of Biomass-fueled generation would be added in 2014. Has this occurred?

Response:

As the tables below indicate, NIPSCO exceeded its expectations for additional renewable generation in 2014 for wind and solar, but did not add the full amount biomass generation in 2014. Of the 10.95 MW of Biomass projected to be installed in 2014, 3.0 MW was in progress and is now expected to go on-line by April 30, 2015. The additional 2.77 MW originally projected to go online in 2014 was to be purchased by NIPSCO but is now being sold to another buyer via transmission interconnect.

Feed-in Tariff (FIT) Installed Generation 2014	
Technology	Generation Capacity (MW)
Wind	0.1
Solar	0.0958
Biomass	3.883
Subtotal	**4.0788**

Net Metering Program Installed Generation 2014	
Technology	Generation Capacity (MW)
Wind	0.0224
Solar	0.3784
Biomass	0
Subtotal	**0.4008**

Purchases From CoGeneration Installed Generation 2014	
Technology	Generation Capacity (MW)
Wind	0
Solar	0
Biomass	1.29
Subtotal	**1.29**

Total Capacity Installed Generation 2014	
Technology	Generation Capacity (MW)
Wind	0.1224
Solar	0.4742
Biomass	5.173
Subtotal	**5.7696**

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Request 1-37:

NIPSCO's optimistic comments about the potential for customer-owned and other distributed generation seem to be inconsistent with the relatively modest amount projected in the IRP. Especially for industrial and large commercial customers, a reasonable case could be made that declining costs of technologies, increasing customer interest, declining cost of natural gas, the potential for CO2 prices to be significant, and the potential changes in NIPSCO's generating fleet with attendant costs might result in an alternative resource plan that may warrant consideration.

Response:

NIPSCO is supportive of distributed generation ("DG") for its customers. In fact, NIPSCO's major industrial customers have over 800 megawatts ("MWs") of DG spread across roughly twenty generation units. The customers utilizing DG have a contractual demand with NIPSCO of roughly 680 MW which means approximately 54% of their demand is met by DG, which is approximately 25% of NIPSCO's total peak demand, making it an integral part of both the customers' and NIPSCO's energy mix.

To further understand the potential for DG in NIPSCO's territory, NIPSCO evaluated multiple DG technologies for the 2014 Integrated Resource Plan ("IRP"). These technologies are fully described and discussed in both Section 7 of the IRP and the Engineering Study by Sargent & Lundy included in Confidential Appendix K. While there may be some positive momentum for DG the following factors were considered as part of NIPSCO's long-term forecast:

- Capital costs are declining for solar but NIPSCO does not see price declines for other DG technologies. Solar costs are higher than grid delivered electricity prices for major industrial customers and are forecasted to remain that way , limiting economic adoption.
- Renewable DG, without the addition of energy storage, is not a good match for NIPSCO's major industrial customers load requirements. The nature of their demand requires dispatchable power and renewable generation is intermittent. The additional cost of energy storage further erodes the economics for these customers.
- DG is a site- and customer-specific deployment of generation. NIPSCO's former affiliates Primary Energy and NiSource Energy Technologies had experience evaluating, developing, deploying and supporting DG as is evidenced by the penetration of DG in NIPSCO. As future generation needs are identified, DG supply and demand fundamentals will continue to be evaluated and DG will be considered as a potential resource alternative.

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Appendix
Response of Northern Indiana Public Service Company to Draft Report

Request 1-38:
Based on NIPSCO's positive experience EV and NIPSCO's efforts to cultivate early adopters of new technology, it is a bit surprising that a similar thought process wasn't considered in customer-owned resources. Moreover, with NIPSCO's positive experience with time of day rates for EVs, does NIPSCO plan to offer more time-differentiated options? One of the more revealing aspects of the NIPSCO EV promotion is that the time-of-day rates do have an effect on customer usage patterns. Specifically, customers avoiding peak periods for the *free* energy between 10 PM and 6 AM. [Cause 44016 approved NIPSCO's *In-Charge Electric Vehicle Pilot* program]. As of July 31, 2014, NIPSCO received 221 enrollment requests and the average usage for charging is 206 kWh per month.
Response:
While NIPSCO will continue to evaluate its electric vehicle ("EV") pilot program going forward, it does not have plans to offer additional time-differentiated options at this time. Since NIPSCO has not implemented AMI (Advanced Metering Infrastructure) and does not currently have plans to implement it in the future, this will prevent NIPSCO from implementing Time of Use Rates. The limited number of customers electing to participate in the EV pilot so far have indicated the potential for time-of-use rates to impact electric usage (see most recent IN-Charge Electric Vehicle Program, Quarterly and Annual Report, Section IV, Pages 30-33 filed April 1, 2015 in Cause No. 44016). The EV pilot is expected to continue through at least January 2017. During this time, the Company will continue to monitor this limited participation for the benefits and costs of a time-of-use program. Please note, in the case of this pilot the energy costs are borne by other customers through the fuel adjustment clause mechanism. NIPSCO will continue to review whether there are indeed any benefits in the form of capacity savings on the system since the incremental energy load of such vehicles are added during off-peak periods.

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Request 1-39:
The Commission staff commends NIPSCO for its conduct of the two in-person stakeholder meetings. It is particularly commendable that NIPSCO's top management and subject matter experts attended the sessions and stayed throughout. This commitment should be well-received by stakeholders. NIPSCO also conducted a webinar, several meetings with groups of stakeholders, and one-on-one meetings with individual stakeholders. NIPSCO also performed several analyses for stakeholders. The Commission staff would be interested in NIPSCO's perspective on whether there are valuable synergies from having more broad stakeholder collaborative meetings than the two. Would that, for example, help NIPSCO and stakeholders better focus their requests for scenario and sensitivity analysis?
Response:
NIPSCO appreciates the recognition of its stakeholder process and its pledge to stakeholders to discuss the Integrated Resource Plan ("IRP") process and substance in a collaborative manner. NIPSCO has learned from this filing process, and it will incorporate those lessons learned into an improved public advisory process for the next filing. In regard to whether there are valuable synergies from having more broad stakeholder collaborative meetings than the two (and one web-based meeting) that NIPSCO hosted, it is possible that further requests for scenario and sensitivity analysis would occur. However, it may not necessarily yield greater focus or results. 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. Those individual discussions yielded the greatest level of attention and detail to provide a more focused scenario and/or sensitivity analysis that the stakeholder requested. NIPSCO found that the one-on-one meetings were more beneficial to address the needs of individual stakeholders than the group setting; specifically, those discussions provided an opportunity to readily respond to specific questions, discuss results and gather further feedback. NIPSCO plans to continue these one-on-one discussions in future public advisory processes for these reasons, and NIPSCO will also continue to have broader meetings as appropriate.

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Request 1-40:
It is the Commission staff's interpretation of the structure of the analysis that NIPSCO hard-wired or predetermined the resource mix that it deemed to be most-cost effective.
Response:
NIPSCO did not "hard-wire" or "predetermine" the resource mix. The optimal plan was the result of optimizations that considered supply-side and demand-side alternatives on an equal footing as discussed on pages 104 and 105.

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Request 1-41:
To help stakeholders make informed decisions that would have reduced the need for NIPSCO to make important foundational decisions, the stakeholder process would have benefited from a better understanding of the risk factors faced by NIPSCO and a better understanding of the elements of IRP. For example, from a risk perspective, NIPSCO could have analyzed a broader spectrum of future natural gas prices, carbon dioxide prices, the timing of carbon regulation, energy efficiency - especially with 111(d) stressing the importance of EE as a compliance measure, renewable energy – again as a compliance measure for 111(d), and customer-owned generation (even if NIPSCO doesn't believe some customer-owned generation is cost-justified, it seems likely some customers will go forward with the projects for non-economic reasons). NIPSCO, for example, might consider different "learning curve" sensitivities that incorporate different prices for various technologies.
Response:
NIPSCO will take this recommendation regarding risk factors under consideration. NIPSCO included a declining price curve for solar photovoltaic resources based on an engineering study conducted by NIPSCO's engineering consultant Sargent & Lundy. See Confidential Appendix K.

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Appendix

Response of Northern Indiana Public Service Company to Draft Report

Request 1-42:
While the Commission staff appreciates NIPSCO began the IRP process before EPA issued its draft rules on June 2, has NIPSCO considered developing strategies to ramp up 111(d) compliance measures such as Energy Efficiency and Renewable Energy? It would seem this would be an appropriate risk analysis that should have been considered by all stakeholders.
Response:
It is important to note that, while NIPSCO did not explicitly include 111(d) compliance with the draft Clean Power Plan ("CPP") rule proposed by the United States Environmental Protection Agency ("EPA") under section 111 (d) of the Clean Air Act ("Draft CPP Rule"), the 2014 IRP included an Aggressive Environmental Scenario that included a 15% renewable portfolio standard ("RPS"), energy efficiency and a cost of carbon (starting in 2020). Coupled together, NIPSCO's Aggressive Environmental Scenario included sensitivities that are reflective of, or more stringent than, the Draft CPP Rule. Because there is much that can change before the rule is final, NIPSCO made the determination that it was not beneficial to conduct specific modeling based on the Draft CPP Rule. Once the rule is finalized, NIPSCO, as prudent business managers, will work with stakeholders to develop a compliance plan that meets customer's needs in an affordable and reliable manner and will include that plan in its future IRP filings. NIPSCO has begun the process of evaluating options for CPP compliance. NIPSCO's evaluation involves the full array of options including energy efficiency, renewable energy, heat rate improvements, coal to gas re-dispatching as well as other options such as retiring current generation and replacing with combined cycle gas turbines. All of the options are being evaluated on a level playing field to ensure that NIPSCO provides its customers with affordable, reliable and compliant energy.