STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

IN THE RULE DEVELOPMENT
PHASE OF RM 15-06

November 19, 2015

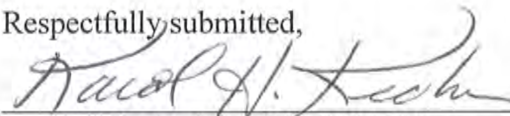
SUBMISSION OF OUCC COMMENTS ON THE COMMISSION'S STRAWMAN DRAFT PROPOSED RULE REVISING CURRENT ADMINISTRATIVE RULES ON INTEGRATED RESOURCE PLANS AND DEMAND-SIDE MANAGEMENT

The Indiana Office of Utility Consumer Counselor ("OUCC") submits these written comments on the Indiana Utility Regulatory Commission's ("Commission") October 22, 2015 Strawman Draft Proposed Rule ("Strawman Rule"). The Strawman Rule presents possible revisions to the Commission's current administrative rules on integrated resource plans ("IRP") (170 IAC 4-7) and demand-side management ("DSM") programs (170 IAC 4-8).

The OUCC would ask the Commission to consider the OUCC's original Comments submitted on August 31, 2015, along with those submitted for the Commission's consideration today. We understand that, since the Commission will promptly post all comments received on the web page for RM 15-06, no service is required on other interested parties.

Finally, the OUCC sincerely thanks the Commission for the time, thought and effort it has devoted to revising its IRP and DSM Rules, both in a prior rulemaking proceeding (RM 11-07) and in this one (RM 15-06).

Respectfully submitted,



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I. OUCC Comments on Strawman Draft IRP Rule, 170 IAC 4-7

A. Need for Continued Focus on Cost-Minimization

A key concept central to Indiana's long-standing IRP requirements was deleted from several sections of the Strawman Rule – namely, the obligation to minimize costs. Because these costs will ultimately be recovered from ratepayers, that requirement is essential. Otherwise, investor owned utilities will focus on increasing earnings or market value for shareholders, not on keeping rates low for consumers. As examples, the following sections of the Strawman IRP Rule should be revised to include specific references to cost minimization requirements, after adjusting for risk:

i. The definition of "IRP" now found in 170 IAC 4-7-1(x);

ii. The definition of "preferred resource portfolio" now found in 170 IAC 4-7-1(hh);

iii. A further discussion of "preferred resource portfolio" in170 IAC 4-7-8(b)(2) and 4-7-8(b)(3);

iv. Additional discussion of "preferred resource portfolio" now found in 170 IAC 4-7-8(b)(7); and

v. The ranked order of portfolios discussed in what is now170 IAC 4-7-8(b)(7)(E) is no longer based on present value of revenue requirement, a method previously used to inform and promote cost minimization.

B. Need to Optimize Use of Cost-Effective Wholesale Market Purchase Options

Electric wholesale markets have changed significantly with the advent of regional transmission operators ("RTOs"), such as the Midcontinent System Operator ("MISO") and PJM. Expanded and improved transmission facilities may also unlock doors to additional sources of electric generation accessible in Indiana at competitive wholesale rates, subject to market pressure imposed by RTOs. Indiana's current IRP Rule was adopted long before the relatively recent growth of RTOs and the expansion of competitive wholesale markets. Despite that recent growth, the Strawman IRP Rule contains only limited references to wholesale purchase options, with little to no mention of RTOs as potentially cost-effective sources of additional energy supply. In light of the high cost of RTO membership ultimately paid by Indiana retail customers, utilities should be urged to consider favorably-priced wholesale sources of electricity before considering construction of new generating facilities. Existing references to wholesale purchase options in the Commission's Strawman Rule are located in the following sections:

i. The definition of "supply-side resource" in170 IAC 4-7-1(ww)(2);

ii. The Strawman Rule proposes deleting all references to firm and non-firm power import transactions and energy purchases involving non-utility generation in 170 IAC 4-7-6(a)(5); and

iii. The guidelines in 170 IAC 4-7-6(c) promote a thorough assessment of commercially available sources of electricity, but fail to mention either of Indiana's RTOs, MISO or PJM.

When customers are expected to pay RTO costs incurred by their electric utilities, those utilities should be expected to analyze and consider wholesale purchase opportunities through RTO markets before pursuing more expensive alternatives to meet retail customer energy demand and capacity requirements.

C. Staggering 3-Year IRP Submissions to Facilitate Public Participation and Improve Coordination with the DSM Planning Process

The OUCC proposed an IRP submission schedule to help transition affected utilities from a two-year to a three-year IRP cycle, while attempting to better coordinate their IRPs with future EE/DSM plans. Under I.C. 8-1-8.5-10(h), DSM plans must be filed at least once every three years. The Commission's Strawman Rule proposed a sequence and rotation schedule that utilities and other stakeholders considered less than optimal. The IURC's proposed IRP schedule placed all investor-owned utilities (i.e., all utilities required to file DSM plans) into the first two years of the IURC's new three-year IRP filing cycle. The OUCC's original proposed schedule presented in its August 31, 2015 Preliminary Comments spread the IOUs' IRP filings across all three years in the new IRP cycle. The OUCC's original proposal is inserted below, together with three additional cycle years, inserted at the end of the list, for purposes of clarification:

170 IAC 4-7-2 Procedures and effects of filing integrated resource plans
Authority: IC 8-1-1-3
Affected: IC 5-14-3; IC 8-1-1-8; IC 8-1-8.5; IC 8-1.5

Sec. 2. (a) The following utilities, or their successors in interest, must submit to the commission an IRP that covers at least a 20-year planning horizon, consistent with this rule, according to the following schedule:

(1) Duke Energy Indiana, Indiana Michigan Power Company, Indiana Municipal Power Agency, and Wabash Valley Power Association on November 1, 2015;

(2) Hoosier Energy Rural Electric Cooperative, Indianapolis Power and Light Company, Northern Indiana Public Service Company, and Southern Indiana Gas and Electric Company on November 1, 2016;

(3) Duke Energy Indiana, Indiana Michigan Power Company and Indiana Municipal Power Agency on November 1, 2017, and every three years thereafter;

(4) Wabash Valley Power Association on November 1, 2017;

(5)Indianapolis Power and Light Company, Northern Indiana Public Service Company, and Hoosier Energy Rural Electric Cooperative on November 1, 2018 and every three years thereafter; and

(6) Southern Indiana Gas and Electric Company and Wabash Valley Power Association on November 1, 2019 and every three years thereafter.

(7) Duke Energy Indiana, Indiana Michigan Power Company and Indiana Municipal Power Agency on November 1, 2020, and every three years thereafter;

(8) Indianapolis Power and Light Company, Northern Indiana Public Service Company, and Hoosier Energy Rural Electric Cooperative on November 1, 2021 and every three years thereafter;

(9) Southern Indiana Gas and Electric Company and Wabash Valley Power Association on November 1, 2022 and every three years thereafter

Upon request of a utility, the director may grant an extension of any such submission dates, for good cause shown.

The OUCC's proposed schedule provides a more gradual transition than the one proposed in the Commission's Strawman Rule. However, the OUCC's proposal will facilitate a balanced and efficient process for Indiana's traditional two-year IRP cycle to be expanded to three years. Spreading the IRP workload across all three years in the IRP cycle will reduce the number of public advisory process meetings conducted each year and the number and volume of IRP submissions that have to be reviewed and analyzed in any given year. The three-year IRP submission cycle is also expected to better balance DSM plan approval caseloads, since I.C. 8-1-8.5-10(j)(3)(B), a new provision added under SEA 412, requires the Commission to consider whether a DSM plan is consistent with the submitting utility's most recent IRP.

II. OUCC Comments on Strawman Draft DSM Rule, 170 IAC 4-8

A. Different Treatment of Energy Efficiency and Demand Response Programs Under SEA 412

Under I.C. 8-1-8.5-9(b), which was revised in 2015 by SEA 412, the term "energy efficiency program" expressly excludes programs designed primarily to reduce demand, programs commonly referred to as "demand response" ("DR") programs. Similarly, SEA 412's definition of "DSM order" makes no mention of DR programs. I.C. 8-1-8.5-9(a).

The Commission's current DSM Rule does not distinguish between EE and DR programs. At the November 5, 2015 rule development workshop, the Commission staff explained that it drafted the Strawman Rule the same way, without differentiating between EE and DR programs, since both types of programs must be considered in developing an IRP. However, since the Indiana General Assembly treats EE and DR programs differently under SEA 412, the Commission's DSM Rule should recognize and accommodate those differences, especially if language in the Strawman Rule directly conflicts with the new statute. (See, e.g., the definition of "DSM program costs" in 170 IAC 4-8-1(i), which conflicts with I.C. 8-1-8.5-9(b) and I.C. 8-1-8.5-10(d).)

The Strawman Rule's use of a single name, "DSM program," to cover both DR and EE programs, fails to acknowledge that certain DSM programs might have elements of both. In I.C. 8-1-8.5-9(b), the Indiana General Assembly recognized that possibility and differentiated between the two types of programs based on whether the program was "designed primarily to reduce demand." However, the statute provides no guidance on how to make that determination. To the extent the Commission is able to draft a proposed rule that includes a list of factors the Commission considers relevant to its determination, that could help focus, if not avert, future litigation on that issue.

B. Recovery of Reasonable EE Program Costs

Under SEA 412, EE "program costs" include the direct and indirect costs of EE programs; the costs associated with evaluation, measurement and verification ("EM&V") of program results; and the final category, "other recoveries or incentives approved by the commission, including lost revenues and financial incentives approved by the Commission under subsection (o)." I.C.8-1-8.5-10(g). The last category of recovery has been the most contentious in recent DSM plan approval cases.

In determining the "overall reasonableness" of future EE plans, I.C. 8-1-8.5-10(j)(2), (7), (8) and (10) requires the Commission to consider, among other factors:

- A cost and benefit analysis of the plan, including the likelihood of achieving the goals of the energy efficiency programs included in the plan.
- The effect, or potential effect in both the long term and the short term, of the plan on the electric rates and bills of customers that participate in energy efficiency programs compared to the electric rates and bills of customer that do not participate in energy efficiency programs;
- The lost revenues and financial incentives associated with the plan and sought to be recovered or received by the electricity supplier; and
- Any other information the commission considers necessary.

If the Commission finds an EE plan to be reasonable, the Commission shall allow recovery of "reasonable lost revenues" and "reasonable financial incentives" that:

(A) encourage implementation of cost effective energy efficiency programs; or

(B) eliminate or offset regulatory or financial bias:

(i) against energy efficiency programs; or

(ii) in favor of supply side resources.

I.C. 8-1-8.5-10(o).

SEA 412 permits the Commission to find, after notice and hearing, that a plan is not reasonable. The order must disclose the reasons behind the Commission's determination. The Commission can either approve parts of the plan found to be reasonable or reject the entire plan if found to be unreasonable. I.C. 8-1-8.5-10(l) and (m). The utility must then submit a modified plan within a reasonable amount of time for further Commission review and rejection or approval. The Indiana General Assembly left it to the Commission to determine the "overall reasonableness" of an EE plan after considering all of the factors identified in I.C. 8-1-8.5-10(j)(1)-(10).

SEA 412 identified general factors to be considered in reviewing a proposed DSM plan. However, it doesn't instruct or guide the Commission's determinations on the overall reasonableness of an EE plan. The OUCC realizes that those determinations are fact-specific and will vary from case-to-case. However, if the Commission has any absolute prerequisites for approval or other result-determinative limits, the Commission may be in a position to provide further regulatory guidance in this or a future rulemaking proceeding. To the extent the Commission identifies conditions or factors that in its judgment would compel rejection or require approval of an EE plan (e.g., failure to meet performance floors or to stay within ceilings

or caps on recovery), providing advance notice to parties through an administrative rule could help focus and, in some situations, avert future litigation on some of the issues, perhaps even some that have been the center of recent debate.

In ongoing litigation, consumer advocates have presented ideas and argument on possible ways the Commission might approach utility lost revenue and financial incentive requests in DSM proceedings. None was acceptable to the petitioning utilities. The Commission could use this rulemaking proceeding to help parties understand how the Commission might weigh the evidence in future litigated proceedings. That approach could provide predictability and enhance fairness by ensuring that the same factors are considered and the same weight given to them under like circumstances in future cases. In some cases, advance notice of rules or guidelines can facilitate settlement of issues that might otherwise have been litigated. Even if settlement is beyond reach, having additional guidance from the Commission through administrative rules could reduce the number of disputed issues or the time required to decide them. It would focus the evidence presented at hearing, centering on issues the Commission has identified as most important to its analysis of EE plans.

To some extent, SEA 412 frees the Commission from prior precedent on cost recovery under DSM riders, allowing the Commission to focus on, among other factors: (i) the <u>reasonableness</u> of amounts proposed for lost revenue recovery and shareholder incentives, and (ii) both the <u>short- and long-term customer bill impacts</u> from proposed EE programs. Such issues are regularly addressed by this Commission and well within its area of expertise.

In past and pending DSM plan approval cases, investor-owned utilities have asked the Commission to approve a level of recovery that would put each utility back in the same position it would have been in without having offered DSM programs. The utilities maintain that they will only be made whole if they are permitted to recover lost revenue for the entire life of each EE measure, without regard to whether total utility sales have actually decreased, and without any subsequent EM&V of measures expected to last more than one year.

In the same cases, consumer representatives have asked the Commission to consider how the dollar amounts utilities are permitted to recover from ratepayers for lost revenue and shareholder incentives might be limited in a fair manner. Consumer representatives maintain that a utility is returned to the same position it would have been in without offering DSM programs if that utility still has the opportunity to recover its full annual revenue requirement. In the utility's next rate case, it will be authorized to recover a new annual revenue requirement, with an updated lost revenue margin rate. Rate cases allow consumer representatives to examine all revenues and all costs. That review occurs as part of a long-standing regulatory process that allows the Commission to fairly balance the interests of monopoly utilities against those of their captive customers protecting both from rates that might otherwise be confiscatory.

C. Rate Case Required to Approve Alternative Rate Mechanisms Such as Decoupling

During the November 5, 2015 public meeting the Commission held in the rule development phase of RM 15-06, it became apparent that some utilities believe the Strawman DSM Rule regarding alternative rate structures in 170 IAC 4-8-5 and 170 IAC 4-8-6 would allow utilities to seek alternative rate relief, beyond approval of EE or DSM riders, in DSM plan approval cases, without conducting a separate base rate case to update the utility's last approved revenue requirement and cost of service study. The Commission has consistently rejected that approach in past DSM cases. See, e.g., *Investigation of Rate Design Alternatives for Natural Gas Utilities*, Cause No. 43180 (IURC 10-21-09), p. 10; *Southern Indiana Gas & Electric Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc.*, Cause No. 43427 (IURC 12-16-09), pp. 34 & 37; and *Citizens Gas and Westfield Gas Corp.*, Cause No. 44124 (IURC 4-10-13), p. 27.

Since the language proposed for Sections 5 and 6 of the Strawman DSM Rule led some utilities to believe that cost recovery methodology can be significantly altered in a DSM case without filing a base rate case, the language in those two sections of the Strawman Rule should be revised to make it clear that the Commission's DSM Rule does not excuse compliance with other applicable rate statutes or previous Commission orders, such as those listed above.

D. Greater Consistency Enhances Transparency and Fairness in Regulation

The Commission's current process for reviewing DSM plans, approving the use of DSM riders, and approving specific dollar amounts in periodic reconciliation or true-up proceedings has permitted inconsistencies to develop over time in how different utilities are:

- Calculating projected future benefits and the avoided cost used in those projections, which impacts both the benefit-cost analysis and shared savings calculations;
- Calculating the lost revenue margin rate used to determine the dollar amount a utility can recover as lost revenues, an ever-growing portion of DSM rider charges;
- Arranging and scheduling EM&V to determine net and gross energy and capacity savings, which are used to calculate the dollar amount recovered as lost revenues; and
- Scheduling additional market potential studies, which could be used to help select the most cost effective array of EE programs, ultimately impacting the mix of supply-side and demand-side resources selected through integrated resource planning.

Since the Commission has authority to promulgate administrative rules, it should give additional thought to how the Commission might address certain recurring issues more

uniformly, or at least more predictably, in future EE plan approval cases. As stated above, using administrative rules to increase regulatory transparency and predictability can aid utility decision-making and planning, potentially leading to more cost-effective EE strategies. Use of rules can also reduce the need to litigate recurring issues in future DSM plan approval cases.

E. Preventing Cost-Recovery of Capital Investments through DSM Riders

With Indiana's large industrial customer opt-out law in I.C. 8-1-8.5-9(e), (f) and (g) and I.C. 8-1-8.5-10(p), and the number of large industrial customers that have opted out of EE programs, the Commission should establish guidelines for capital cost recovery to fairly balance different customers' interests. Cost recovery for utility capital investments associated with EE programs should occur through base rates, under a Commission-approved cost of service study. Customers that choose not to opt-out of EE programs or who are not eligible to do so should not be forced to bear an unfair portion of the cost of EE programs that involve utility infrastructure improvements that benefit all customers.

F. Making Future Savings Count Under Clean Power Plan

It is too early to predict exactly how and when Indiana might be required to implement federal environmental regulations aimed at reducing carbon dioxide emissions from power plants. However, if or when that occurs, the Commission should be poised to further amend its DSM Rule as needed to comply with any new federal requirements that would otherwise prevent Indiana from counting all energy and capacity savings from DSM programs toward any applicable federal emission reduction requirements.

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