

August 5, 2016

WRITER'S DIRECT NUMBER: (317) 236-2208  
DIRECT FAX: (317) 592-4276  
EMAIL: Kay.Pashos@icemiller.com

Jeremy Comeau  
Assistant General Counsel  
Indiana Utility Regulatory Commission  
101 W. Washington St., Ste. 1500 East  
Indianapolis, IN 46204  
317.232.2102 (Tel.)  
[jcomeau@urc.in.gov](mailto:jcomeau@urc.in.gov)

**RE: IURC Rulemaking #15-06; Integrated Resource Plans and DSM (Rule 7 – 170 IAC 4-7 and Rule 8 – 170 IAC 4-8)**

Dear Jeremy:

The Indiana investor-owned electric utilities<sup>1</sup> (the “Utilities”) appreciate the opportunity to submit comments on the Indiana Utility Regulatory Commission’s (“Commission”) Rulemaking #15-06 concerning Integrated Resource Planning (“IRP”) and Demand Side Management (“DSM”) programs. The Utilities are already working under the proposed rules in preparation of their upcoming IRPs and believes the proposed rules offer a solid balance between informing stakeholders about the process used to develop the IRP while recognizing that the utilities are ultimately responsible for their integrated resource plans and the investments that are supported by their respective IRPs. The Utilities have a few recommendations regarding the changes proposed to the July 5, 2016 strawman rules. Those recommendations are set forth below. Also enclosed is a “redlined” version of the Commission’s latest strawman rules, marked to show the changes we suggest.

Definition of “avoided cost” – 170 IAC 4-7-1(b)

As written, the definition of avoided cost is appropriate for MISO participants. We recommend that the phrase “or marginal” be added (after “incremental”) to reflect the PJM market price structure.

The preferred resource portfolio - 170 IAC 4-7-1(bb) and 4-7-8 (c)(5)

The third strawman changes the definition of a preferred resource portfolio by substituting the description of “economic” with “cost-effective.” The Utilities are not opposed to this revision provided that the Commission is not intending to deviate from its well-established precedent of evaluating resource needs. We do not interpret the adoption of the phrase cost-

<sup>1</sup> Duke Energy Indiana, Inc., Indiana Michigan Power Co., Indianapolis Power & Light Co., Northern Indiana Public Service Co., and Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.

effective as such a change, but urge the Commission not to embark on such a change if that is the intention.

Indiana Code ch. 8-1-8.5 utilizes both the terms “economic” and “cost effective.” Compare Ind. Code §§ 8-1-8.5-4 (requiring consideration of “[o]ther methods for providing reliable, efficient, and economical electric service”) and 8-1-8.5-3(e) (requiring a utility to submit an IRP to meet future electric resource needs that is “cost effective and reliable”). Indiana has long judged the merits of a proposed generation facility on whether it is consistent with “providing reliable, efficient and economic service.” (Emphasis added) *Indianapolis Power & Light Co.*, Cause No. 44339, at 20 (IURC 5/14/2014); *Joint Petition of PSI Energy, Inc. and CINCAP VII, LLC*, Cause No. 42145, at 4 (IURC 12/29/2002); *PSI Energy, Inc.*, Cause No. 39175, at 14 (IURC 5/13/1992). While the Commission has long considered the cost-effectiveness of a resource portfolio, the analysis provides more flexibility than simply cost-effectiveness, safety and reliability. “If an Indiana utility reasonably considers and evaluates the statutorily required options for providing reliable, efficient, and economic service, then the utility should, in recognition that it bears the service obligations of IC 8-1-2-4, be given some discretion to exercise its reasonable judgment in selecting the option or options to implement which minimize the cost of providing such service.” *Indianapolis Power & Light Co.*, Cause No. 44339, at 20 (IURC 5/14/2014); *Joint Petition of PSI Energy, Inc. and CINCAP VII, LLC*, Cause No. 42145, at 4 (IURC 12/29/2002); *PSI Energy, Inc.*, Cause No. 39175, at 14 (IURC 5/13/1992). The more comprehensive framework developed by the Commission over its many years of experience evaluating resource needs has led to a robust standard that serves Indiana’s interests.

#### Integrated Resource Plan Submission - 170 IAC 4-7-2

Section 2(d)(2)(B) refers to a 120-day deadline. However, elsewhere this was changed to a 90-day deadline, and it should be changed to 90 days here too.

#### Resource Adequacy Assessment Report – 170 IAC 4-7-2.2

The Utilities suggest that subsection (b), requiring explanations of “any differences” between resource adequacy assessments reported to a RTO and IRPs, be deleted or modified to be more specific. “Any” differences” is simply too broad and burdensome a requirement given the substantial data included in both resource adequacy assessments and IRPs. If this subsection is ultimately included in the rules, the Utilities suggest that it be limited to a requirement to explain “any major differences in the information provided under subsection (a) with the utility’s most recent IRP, such as significant changes in capacity additions or retirements or significant changes in the timing of such.”

Additionally, this section as written is not clear that this is referring to the *annual* resource adequacy assessment reported to a regional transmission organization. The Utilities suggest adding the word “annual” in front of the phrase “resource adequacy assessment.”

Waiver or variance requests - 170 IAC 4-7-3

Section 3(e) refers to “interested parties” here, but it is not clear that it is using it in a defined term context. We suggest that interested party as used here should be defined as it is used in Section 2(d)(2)(B) for purposes of clarity.

Integrated resource plan contents - 170 IAC 4-7-4

In 170 IAC 4-7-4(24)(C), the Commission’s strawman IRP rules outline the requirements of the utility’s base case scenario. According to the proposal, the base case may not include future resources, laws or policies unless certain criteria are met. The first criteria originally required the utility to solicit stakeholder input before including future resources, laws or policies. This draft of the strawman significantly changes this condition, requiring the utility to receive stakeholder support before inclusion. The previous approach is the more appropriate approach.

Stakeholders ought to understand and be afforded an opportunity to comment on future resources, laws or policies included in the analysis. If a utility intends to include some future resource, law or policy without explanation, it may have impacts on the modeling that are not understood by the stakeholders. Requiring disclosure and opportunity for feedback from stakeholders is consistent with the spirit of the stakeholder process. The second strawman achieved this objective.

This draft of the strawman goes much further, however, prohibiting inclusion of future resources, laws or policies absent “stakeholder support.” This is not consistent with the recognition in the IRP rules that the utility retains full responsibility for the content of its IRP. 170 IAC 4-7-2.6(d). Stakeholders may desire to ignore reasonably anticipated resources, laws or policies that the utility believes are very likely to occur and will have a significant impact on its analysis. Stakeholders that disagree are free to pursue their point of view in any CPCN proceeding, but a utility should not be constrained from considering future resources, laws or policy because stakeholders do not “support” such consideration.

The standard is also unclear. Is it enough if some stakeholders “support” inclusion of the future resource, law or policy while others do not? Must the utility have a unanimous vote of stakeholders? How are the stakeholders to be formally identified? What if some support and others object? Is it enough if the utility supports consideration? Rather than trying to sort through the unanswered questions presented by the proposed revision, we respectfully submit that the Commission should revert to the prior language.

Description of Available Resources - 170 IAC 4-7-6

Note that in Subsection (6)(b)(2), “(E)” is listed twice; the second listing should be changed to “(F).”

Resource portfolios - 170 IAC 4-7-8

170 IAC 4-7-8(c)(6) would require an evaluation of the utility’s DSM programs designed to defer or eliminate investment in a transmission or distribution facility including their impacts on the utility’s transmission and distribution system for the first ten (10) years of the planning

period. The Utilities submit that this requirement could make compliance with the rules unduly burdensome, and recommend deleting it.

#### Definitions – 170 IAC 4-8-1

We suggest adding a definition for DSM costs in 170 IAC 4-8-1. “DSM costs” is defined in 4-7-1 but not 4-8-1. We suggest using the same definition as is in 4-7-1, similar to how energy efficiency is defined in both sections 4-7 and 4-8.

Section 1(u), which defines income effect, needs clarification because the utility cannot impact disposable income of the customer except through bill savings.

#### Energy Efficiency Plan Filing - 170 IAC 4-8-2

In Section 2(a)(5), we suggest capitalizing the term "commission analysis" so that it is clear that this subsection is referencing the defined term in Section 4-8-1(d).

In Section 2(b)(13), the requirement references workpapers and data used for calculation of the tests performed under Subsections 3, 8, and 9 of this section. Subsection 8 relates to lost revenues however, and is technically not a "test" performed. We suggest revising this to refer to calculations performed.

#### Evaluation, Measurement and Verification Plan - 170 IAC 4-8-4

Section 4(a)(4) refers to optimizing market penetration, minimizing free riders, and measuring spillover, in the context of an evaluation, measurement and verification plan. However, these actions don't really fit in an EM&V plan. Rather this subsection should refer to "measure the effectiveness of the actions." The EM&V plan should not recommend actions in the plan, but an actual report may include recommendations.

Sections 2(a)(10) and 4(a) require that or at least seem to require that the EM&V plan be included in the utility's submission of its energy efficiency plan to the commission. We believe it would be preferable to require the EM&V procedures to be submitted to the Commission with its proposed plan, but allow the actual EM&V plan be submitted to the Commission separately at a later time. That would allow the utilities flexibility to submit such EM&V plan after choosing a vendor, getting oversight board approval, etc.

Section 4(a)(6) requires a method to measure the income effect for an energy efficiency program and demand response program. We are not aware of a method to measure "income effects." That would require asking the customer participant to provide the evaluator with their change in disposable income, not just changes due specifically to the program. If this definition of "income effect" is not narrowed to be only effects from lower utility bills, then it is not possible to measure this.

#### Cost Impact

The requirement to conduct the public advisory process, the world view analysis and the risk analysis have all increased relatively smaller utilities' costs of conducting the IRP. We estimate that in total the increased cost for such a utility is over \$300,000.

Jeremy Comeau  
Assistant General Counsel  
Indiana Utility Regulatory Commission  
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Additionally, because utilities have undertaken activities to effectively treat energy efficiency on the same basis as supply side resources within IRP modeling, this level of modeling of energy efficiency measures requires reasonable estimates of baseline alternatives, incremental measure cost, rebate levels, and attributes such energy and demand savings, all appropriate to individual utility service area demographics and market conditions. Utility-specific Market Potential Studies are a tool that can yield these necessary attributes for modeling but can cost several hundred thousand dollars per study. Because energy efficiency markets tend to change quickly, and if an updated MPS is needed for each IRP cycle (3 Years), the additional cost required to do these studies at this frequency can be significant compared to what has been incurred in the past.

Utilities anticipate cost savings from the move from two- to a three-year IRP, although this is dependent upon the assumption that regular updates in-between filings will not be requested by the Commission or its staff.

The Utilities appreciate the time and effort the Commission staff has devoted to developing these rules. We strongly believe that adoption of the recommendations made by the Utilities will lead to better rules.

Sincerely,

ICE MILLER LLP



Kay Pashos

*Counsel for the Indiana Energy Association, and authorized to submit these comments on behalf of Duke Energy Indiana, Inc., Indiana Michigan Power Co., Indianapolis Power & Light Co., Northern Indiana Public Service Co., and Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.*

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**TITLE 170 INDIANA UTILITY REGULATORY COMMISSION**

**Proposed Rule**

LSA Document #15-xxx

**DIGEST**

Amends 170 IAC 4-7 to update the commission's rule requiring electric utilities to prepare and submit integrated resource plans and amends 170 IAC 4-8 to update the commission's rule regarding utilities' energy efficiency plans. Effective 30 days after filing with the Publisher.

**170 IAC 4-7-0.5**

**170 IAC 4-7-1**

**170 IAC 4-7-2**

**170 IAC 4-7-2.1**

**170 IAC 4-7-2.2**

**170 IAC 4-7-2.5**

**170 IAC 4-7-2.6**

**170 IAC 4-7-2.7**

**170 IAC 4-7-3**

**170 IAC 4-7-4**

**170 IAC 4-7-5**

**170 IAC 4-7-6**

**170 IAC 4-7-7**

**170 IAC 4-7-8**

**170 IAC 4-7-9**

**170 IAC 4-7-10**

**170 IAC 4-8-1**

**170 IAC 4-8-2**

**170 IAC 4-8-3**

**170 IAC 4-8-4**

**170 IAC 4-8-5**

**170 IAC 4-8-6**

**170 IAC 4-8-7**

**170 IAC 4-8-8**

**SECTION 1. 170 IAC 4-7-0.5 IS ADDED TO READ AS FOLLOWS**

**170 IAC 4-7-0.5 Purpose and Applicability**

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-2.2; IC 8-1-2.3-2; IC 8-1-2.4; IC 8-1-8.5; IC 8-1-8.8-10; IC 8-1.5

Sec. 0.5 (a) The purpose of this rule is to provide the specific requirements for submission of utilities' integrated resource plans required by IC 8-1-8.5-3(e).

(b) This rule applies to a utility, as defined in this rule, unless otherwise noted. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-0.5*)

SECTION 2. 170 IAC 4-7-1 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-1 Definitions

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-2.2; IC 8-1-2.3-2; IC 8-1-2.4; IC 8-1-8.5; IC 8-1-8.8-10; IC 8-1.5

Sec. 1. (a) The definitions in this section apply throughout this rule.

(b) “Avoided cost” means the incremental or marginal cost to a utility of energy or capacity, or both, not incurred by a utility if an alternative supply-side resource or demand-side resource is included in the utility’s IRP.

(c) “Candidate resource portfolio” means one of multiple long-term resource portfolios selected for further evaluation through the utility’s portfolio screening process to determine the preferred resource portfolio.

(d) “Cogeneration facility” means the following:

(1) A facility that simultaneously generates electricity and useful thermal energy and meets the energy efficiency standards established for a cogeneration facility by the Federal Energy Regulatory Commission (FERC) under 16 U.S.C. 824a-3.

(2) The land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility.

(3) The transmission or distribution facilities necessary to conduct the energy produced by the facility to a user located at or near the project site.

(e) “Commission” means the Indiana utility regulatory commission.

(f) “Commission analysis” means the required state energy analysis developed by the commission under IC 8-1-8.5-3.

(g) “Contemporary issues” means any topic that may affect the inputs, methods, or judgment factors in an IRP and is common to the utilities. Topics may include, but are not limited to, the following:

(1) Economic.

(2) Financial.

(3) Environmental.

(4) Energy.

(5) Demographic.

(6) Customer.

(7) Methodological.

(8) Regulatory.

(9) Technological

(h) “Demand-side management program” or “DSM program” means a utility program designed to implement demand response, energy efficiency, or both.

(i) “Demand response” means a reduction in demand for limited intervals of time, such as during peak electricity usage or emergency conditions.

(j) “Demand-side resource” means one or more demand-side management programs.

(k) “Director” means an employee of the commission designated as the IRP director by the commission’s agency head appointed under IC 8-1-1-2(d).

(l) “Distributed generation” means an electrical generating facility located at or near a customer’s point of use, which may be connected in parallel operation to the utility system.

(m) “DSM costs” refers to all expenses incurred by a utility in a given year for operation of a DSM program, whether the cost is capitalized or expensed. Expenses include, but are not limited to, the following:

- (1) Administration.
- (2) Equipment.
- (3) Incentives paid to program participants.
- (4) Marketing and advertising.
- (5) Evaluation, measurement and verification.

(n) “Emission allowance” means the authority to emit one (1) unit of any air pollutant as specified by a federal or state regulatory system.

(o) “End-use” means the light, heat, cooling, refrigeration, motor drive, microwave energy, video or audio signal, computer processing, electrolytic process, or other useful work produced by equipment using electricity

(p) “Energy efficiency” means reduced energy use for a comparable or improved level of energy service.

(q) “Energy service” means the light, heat, motor drive, and other service for which a customer purchases electricity from the utility.

(r) “Energy storage” means a:

- (1) technology; or
- (2) set of technologies;

Capable of storing previously generated energy and discharging that energy as electricity at a later time.

(s) “Engineering estimate” means a calculated estimate of the change in energy (kWh) and demand (kW) resulting from a DSM program, accounting for dynamic interactions between or among the DSM programs.

(t) “FERC Form 715” means the annual transmission planning and evaluation report required by the Federal Energy Regulatory Commission (FERC), as adopted in 58 FR 52436, Oct. 8, 1993, and as amended by Order 643, 68 FR 52095, Sep. 2, 2003.

(u) “Firm wholesale power sale” means a power sale intended to be available to the purchaser at all times, including under adverse conditions, during the period covered by the commitment.

(v) “Integrated resource plan” or “IRP” means a utility’s document or documents submitted to the commission in order to meet the requirements of this rule.

(w) “Load research” means the collection of electricity usage data through a metering device associated with an end-use, a circuit, or a building. The metered data is used to better understand the characteristics of electric loads, the timing of their use, and the amount of electricity consumed by users. The data may be collected over a variety of time intervals, usually sixty (60) minutes or less.

(x) “Load shape” means the time pattern of customer electricity use and the relationship of the level of energy use to a specific time during the day, month, and year.

(y) “North American Industrial Classification System” or “NAICS” refers to the system developed by the United States Department of Commerce for use in the classification of establishments by type of activity in which a business is engaged.

(z) “OUCC” means the Indiana office of utility consumer counselor.



“Penetration” means the ratio of the number of a specific type of new appliances or end-use equipment installed to the total number installed during a given time.

(aa) “Power transfer capability” means the amount of power that can be transferred from one point or part of the bulk electric system to another without exceeding any reliability criteria pertinent to the utility.

(bb) “Preferred resource portfolio” means the utility’s selected long-term supply-side resource and demand-side resource mix that safely, cost-effectively, and reliably meets the electric system demand taking cost, risk, and uncertainty into consideration.

(cc) “Present value” means the current value of a future sum or stream of money, calculated by discounting the sum or stream of money by an interest rate.

(dd) “Program Participant” means a utility customer participating in a DSM program.

(ee) “Public advisory process” refers to the procedures in section 2.1 of this rule in which customers and interested parties have the opportunity to receive information from the utilities, provide input for the utility to consider in the development of the IRP, and comment on a utility’s IRP.

(ff) “Regional transmission organization” or “RTO” means the regional transmission organization approved by the Federal Energy Regulatory Commission for the control area that includes the utility’s assigned service area as defined in IC 8-1-2.3-2.

(gg) “Renewable resource” means a renewable energy resource as defined in IC 8-1-8.8-10.

(hh) “Resource” means a facility, project, contract, or other mechanism used by a utility to assist in providing electric energy service to the customer.

(ii) “Resource action” means a resource change or addition proposed by a utility in a formally docketed commission proceeding.

(jj) “Risk metric” means a measure used to gauge the risk associated with a resource portfolio. As applied to the cost of a resource portfolio, risk metric includes measures of the variability of costs and the magnitude of outcomes.

(kk) “Saturation” means the ratio of the number of a specific type of similar appliances or end use equipment to the total number of customers in that class or the total number of similar appliances or end use equipment in use.

(ll) “Screening” means an evaluation performed by a utility to determine whether a demand-side or supply-side resource option is eligible for potential inclusion in the utility’s preferred resource portfolio

(mm) “Short term action plan” means a schedule of activities and goals developed by a utility to begin efficient implementation of its preferred resource portfolio as required by subdivision 4(10) of this rule.

(nn) “Smart grid” means use of digital electronics, equipment, or data, and the associated communications networks, to monitor and control aspects of the electrical transmission and distribution system from generation to consumption.

(oo) “Supply-side resource” means a resource that provides a supply of electrical energy or capacity, or both, to a utility. A supply-side resource may include, but is not limited to, the following:

- (1) A utility-owned generation capacity addition.
- (2) A wholesale power purchase.
- (3) Refurbishing or upgrading an existing utility-owned generation facility.
- (4) A cogeneration facility.

- (5) A renewable resource.
- (6) Distributed generation.

(pp) "Utility" means:

- (1) a public, municipally owned, or cooperatively owned electric utility; or
- (2) a joint agency created under IC 8-1-2.2;

unless the utility is exempt under IC 8-1-8.5-7.

*(Indiana Utility Regulatory Commission; 170 IAC 4-7-1; filed Aug 31, 1995, 9:00 a.m.: 19 IR 16; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)*

SECTION 3. 170 IAC 4-7-2 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-2 Integrated Resource Plan Submission

Authority: IC 8-1-1-3; IC 8-1-8.5-3

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, shall submit to the commission an IRP consistent with this rule according to the following schedule:

(1) Hoosier Energy Rural Electric Cooperative shall submit an update of its 2014 IRP by November 1, 2016, consistent with subsection 10(b) of this rule.

(2) Indianapolis Power and Light Company, Northern Indiana Public Service Company, and Southern Indiana Gas and Electric Company by November 1, 2016, and every three years thereafter.

(3) Indiana Municipal Power Agency, Hoosier Energy Rural Electric Cooperative and Wabash Valley Power Association by November 1, 2017, and every three years thereafter.

(4) Duke Energy Indiana, and Indiana Michigan Power Company, by November 1, 2018, and every three years thereafter.

(b) Upon request of a utility, the director may grant an extension of a submission deadline, for good cause shown.

(c) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents:

(1) The integrated resource plan.

(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the assumptions in the IRP.

(3) An IRP summary that communicates core IRP concepts and results to non-technical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following:

(A) A brief description of the utility's:

(i) existing resources;

(ii) preferred resource portfolio;

(iii) key factors influencing the preferred resource portfolio;

(iv) short term action plan;

(v) the IRP public advisory process; and

(vi) any additional details the commission staff may request.

(B) A simplified discussion of resource types and load characteristics.

The utility shall make the IRP summary readily accessible on its website.

(d) Contemporaneously with the submission of an IRP under this section, a utility shall provide to the director the following information:

(1) The name and address of each known individual or entity considered by the utility to be an interested party.

(2) A statement that the utility has sent each known interested party, electronically or by deposit in the United States mail, First Class postage prepaid, a notice of the utility's submission of the IRP to the commission. The notice must include the following information:

(A) A general description of the subject matter of the submitted IRP.

(B) A statement that the commission invites interested parties to submit written comments on the utility's IRP within ~~90~~90 days of the IRP submittal.

An interested party includes any business, organization, or particular customer that participated in the utility's previous public advisory process or submitted comments on the utility's previous IRP. A utility is not required to separately notify all of its customers.

(3) A statement that the utility has served a copy of the documents submitted under subsection (d) of this section on the OUCC. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2; filed Aug 31, 1995, 9:00 a.m.: 19 IR 18; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; errata filed Jul 21, 2009, 1:33 p.m.: 20090819-IR-170090571ACA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA*)

SECTION 4. 170 IAC 4-7-2.1 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.1 Public Comments and Director's Reports

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 5-14-3; IC 8-1-1-8; IC 8-1-8.5; IC 8-1.5

Sec. 2.1. (a) A customer or interested party may comment on an IRP submitted to the commission. A comment must:

(1) be in writing;

(2) be received by the commission within ninety (90) days from the date a utility submits its IRP to the commission;

(3) be electronically submitted to the director or as otherwise accepted by the directors;

(4) clearly identify the utility upon which written comments are submitted; and

(5) be provided to the utility using the utility contact information provided in the IRP.

(b) The director shall issue a draft report on the IRP no later than one hundred and fifty (150) days from the date a utility submits its IRP to the commission.

(c) Supplemental or response comments may be submitted by:

(1) the utility;

(2) a customer; or

(3) an interested party.

(d) Supplemental or response comments must be:

(1) in writing;

- (2) received by the commission within thirty (30) days from the date the director issues the draft report;
- (3) electronically submitted to the director or submitted through an electronic filing system if requested by the director; and
- (4) provided to:
  - (A) the utility;
  - (B) each customer or interested party that submitted written comments; and
  - (C) the OUCC.
- (e) The director may allow additional written comment periods or extend the submission deadline for written comments or supplemental or response comments by notifying the utility and interested parties.
- (f) The director shall issue a final report on the IRP within 30 days following the deadline for supplemental or response comments.
- (g) The draft report and the final report shall:
  - (1) be limited to commenting on the IRP's compliance with the requirements of this rule;
  - (2) list all areas where the director believes the IRP fails to comply with the requirements of this rule; and
  - (3) not comment on:
    - (A) the desirability of the utility's preferred resource portfolio; and
    - (B) a proposed resource action in the IRP.
- (h) The director may extend the deadlines for issuance of the draft report and the final report by notifying the utility and interested parties.
- (i) Failure by the director to issue a draft or final report by the applicable deadline shall result in a presumption that the IRP complies with this rule.
- (j) Subject to IC 5-14-3 and any determination by the commission regarding confidentiality under 170 IAC 1-1.1-4, the commission shall make publicly available on the commission's website or other electronic document system:
  - (1) The utilities' IRPs.
  - (2) Written comments.
  - (3) Supplementary and responsive comments.
  - (4) The director's draft report.
  - (5) The director's final report. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2.1*)

SECTION 5. 170 IAC 4-7-2.2 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.2 Resource Adequacy Assessment Report

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 5-14-3; IC 8-1-1-8; IC 8-1-8.5; IC 8-1.5

Sec. 2.2. (a) Each utility listed in subsection 2(a) of this rule shall provide to the director and the OUCC the annual resource adequacy assessment reported to a regional transmission organization within 25 days of the date reported or as otherwise agreed by the director. (b) A utility providing information as required in subsection (a) shall explain any major differences in the information provided under subsection (a) with the utility's most recent IRP, such as significant changes in capacity additions or retirements or significant changes in the timing of such. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2.2*)

SECTION 6. 170 IAC 4-7-2.5 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.5 Effects of Integrated Resource Plans in Docketed Proceedings

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 5-14-3; IC 8-1-1-8; IC 8-1-8.5; IC 8-1.5

Sec. 2.5. (a) The failure of an interested party to file comments under this rule shall not constitute a waiver of any right to participate as a party or to advance an argument or position in a formally docketed proceeding before the commission. Similarly, the content of comments filed by an interested party under this rule shall not preclude that party from advancing an argument or position in a formally docketed proceeding before the commission, whether or not that argument or position was raised in comments submitted under this rule.

(b) When a utility takes a resource action, it shall be consistent with the most recent IRP submitted under this rule, including its:

- (1) inputs;
- (2) data and assumptions;
- (3) methods;
- (4) models;
- (5) judgment factors; and
- (6) rationales used to determine inputs, methods, and risk metrics;

unless any differences between the most recent IRP and the resource action are fully explained and justified with supporting evidence, including an updated IRP analysis.

(c) Documents submitted to the commission or created pursuant to this rule may be used as follows:

- (1) To assist the commission in the preparation of the commission analysis.
- (2) In the preparation of a commission staff report in formally docketed proceedings before the commission.
- (3) As evidence in a formally docketed proceeding before the commission if admitted.

(*Indiana Utility Regulatory Commission; 170 IAC 4-7-2.5*)

SECTION 7. 170 IAC 4-7-2.6 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.6 Public advisory process

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5

Sec. 2.6. (a) The following utilities are exempt from this section:

- (1) Indiana Municipal Power Agency;
- (2) Hoosier Energy Rural Electric Cooperative; and
- (3) Wabash Valley Power Association.

(b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP.

(c) The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by interested parties, the OUCC, the commission, and its staff.

(d) The utility retains full responsibility for the content of its IRP.

(e) The utility shall conduct a public advisory process as follows:

(1) Prior to submitting its IRP to the commission, the utility shall hold at least three meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following:

- (A) An introduction to the IRP and public advisory process.
- (B) The utility's load forecast.
- (C) Evaluation of existing resources.
- (D) Evaluation of supply and demand-side resource alternatives, including:
  - (i) associated costs;
  - (ii) quantifiable benefits; and
  - (iii) performance attributes.
- (E) Modeling methods.
- (F) Modeling inputs.
- (G) Treatment of risk and uncertainty.
- (H) Discussion seeking input on its candidate resource portfolios.
- (I) The utility's scenarios and sensitivities.
- (J) Discussion of the utility's preferred resource portfolio and the utility's

rationale for its selection.

(2) The utility is encouraged to hold additional meetings as appropriate.

(3) The schedule for meetings shall be determined by the utility and shall:

- (A) be consistent with its internal IRP development schedule; and
- (B) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.

(4) The utility or its designee shall:

- (A) chair the participation process;
- (B) schedule meetings;
- (C) develop and publish to its website agendas and relevant material for those meetings at least seven (7) calendar days prior to the meeting; and
- (D) develop and publish to its website meeting minutes within fifteen (15) calendar days following each meeting;

(5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility.

(6) The utility shall take reasonable steps to notify:

- (A) its customers;
- (B) the commission;
- (C) interested parties; and
- (D) the OUCC.

of its public advisory process. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2.6*)

**SECTION 8. 170 IAC 4-7-2.7 IS ADDED TO READ AS FOLLOWS:**

**170 IAC 4-7-2.7 Contemporary issues technical conference**

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5

Sec. 2.7. (a) The commission or its staff may host an annual technical conference to facilitate:

- (1) identifying contemporary issues;
- (2) identifying best practices to manage contemporary issues; and
- (3) instituting a standardized IRP format.

(b) The agenda of the technical conference shall be set by the commission staff. Utilities, the OUCC, and interested parties may request commission staff include specific contemporary issues and presenters.

(c) The director may designate specific contemporary issues for utilities to address in the next IRPs by providing the utilities and interested parties with the contemporary issues to be addressed.

(d) Utilities shall discuss the designated contemporary issues in the next IRP if the contemporary issues were designated by the director at least one (1) year prior to the submittal date of the utility's IRP. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2.7*)

**SECTION 9. 170 IAC 4-7-3 IS AMENDED TO READ AS FOLLOWS:**

**170 IAC 4-7-3 Waiver or variance requests**

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 5-14-3; IC 8-1-2-29; IC 8-1-2.2; IC 8-1-8.5-7; IC 8-1.5

Sec. 3. (a) A utility may request a variance from a provision of this rule for good cause.

(b) A request under this section shall:

- (1) Describe the situation which necessitates the variance.
- (2) Identify the provision of this rule for which the variance is requested.
- (3) Explain the difference between the expected effects of complying with this rule on the utility, its customers, and interested parties in the public advisory process if the variance is denied and the expected effect on the parties if accepted.
- (4) Explanation of how the variance is expected to aid the implementation of this rule.
- (5) A request shall be submitted in sufficient time that the IRP submittal schedule shall not be adversely affected.

(c) The director shall respond in writing regarding acceptance or denial of a request under this section within fifteen (15) calendar days. The request shall not be unreasonably denied, and

any denials shall include the reason for the denial. If the director fails to respond within fifteen (15) calendar days, the request shall be deemed accepted.

(d) The request by the utility and the director's acceptance or denial shall be posted on the commission's website or other publically accessible electronic document system.

(e) An interested party may appeal to the full commission the director's acceptance or denial under this section. An appeal to the full commission must be filed with the commission in a docketed proceeding and provided to the utility, the OUCC, and other interested parties within thirty (30) days of the posting of the director's written acceptance or denial of the request. An interested party includes any business, organization, or particular customer that participated in the utility's previous public advisory process or submitted comments on the utility's previous IRP.

*(Indiana Utility Regulatory Commission; 170 IAC 4-7-3; filed Aug 31, 1995, 9:00 a.m.: 19 IR 19; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)*

SECTION 10. 170 IAC 4-7-4 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-4 Integrated Resource Plan Contents

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1; IC 8-1.5

Sec. 4. An IRP must include the following:

- (1) At least a 20 year future period for a predicted or forecasted analysis.
- (2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with subsection 5(a) of this rule.
- (3) At least three (3) alternative forecasts of peak demand and energy usage in compliance with subsection 5(b) of this rule.
- (4) A description of the utility's existing resources in compliance with subsection 6(a) of this rule.
- (5) A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis if performed.
- (6) A description of the possible alternative future resources for meeting future demand for electric service in compliance with subsection 6(b) of this rule.
- (7) The resource screening analysis and resource summary table required in section 7 of this rule.
- (8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with subsection 8(a) and 8(b) of this rule.
- (9) A description of the utility's preferred resource portfolio and the information required in compliance with subsection 8(c) of this rule.
- (10) A short term action plan listing plans for the next three year period to implement the utility's preferred resource portfolio and its workable strategy. The short term action plan shall comply with section 9 of this rule.
- (11) A discussion of the:
  - (A) inputs;
  - (B) methods; and



(C) definitions  
used by the utility in the IRP.

(12) Appendices of the data sets and data sources used to establish alternative forecasts in subsection 5(b) of this rule. If the IRP references a third party data source, the IRP must include the following for the relevant data:

- (A) source title;
- (B) author;
- (C) publishing address;
- (D) date;
- (E) page number; and
- (F) an explanation of any adjustments made to the data.

The data must be submitted within two weeks of submitting the IRP in an editable format, such as a comma separated value file or excel spreadsheet format.

(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by the following:

- (A) customer class;
- (B) rate class;
- (C) NAICS code;
- (D) DSM program; and
- (E) end-use.

(14) The database in subdivision (13) may be developed using, but not limited to, the following methods:

- (A) Load research developed by the individual utility.
- (B) Load research developed in conjunction with another utility.
- (C) Load research developed by another utility and modified to meet the characteristics of that utility.
- (D) Engineering estimates.
- (E) Load data developed by a non-utility source.

(15) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.

(16) A discussion detailing how information from Advanced Metering Infrastructure (AMI) and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.

(17) A discussion of distributed generation within the service territory and its potential effects on generation, transmission, and distribution planning and load forecasting.

(18) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.

(19) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.

(20) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission have been taken into account and influenced the IRP development.

(21) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.

(22) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.

(23) A discussion of how the utilities' resource planning objectives, such as cost effectiveness, rate impacts, risks and uncertainty, were balanced in selecting its preferred resource portfolio.

(24) A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria:

(A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs.

(B) Include existing federal environmental laws; existing state laws, such as renewable energy requirements and energy efficiency laws; and existing policies, such as tax incentives for renewable resources.

(C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable.

(D) Not include future resources, laws, or policies unless:

~~(i) the utility subject to section 2.6 of this rule~~ receives stakeholder input ~~on supporting~~ the inclusion and it meets the following conditions:

(ii) Future resources have obtained all necessary regulatory approvals; and

(iii) Future laws and policies have a high probability of being enacted.

A base case scenario need not align with the utility's preferred resource portfolio.

(25) A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.

(26) A brief description, focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715:

(A) The most current power flow data models, studies, and sensitivity analysis.

(B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. This description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC).

(C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following:

(i) the limits of the utility's transmission use;

(ii) the utility's assessment practices developed through experience and study; and

(iii) operating restrictions and limitations particular to the utility.

(27) A list and description of the methods utilized by the utility in developing the IRP, including the following:

(A) For models used in the IRP, the model's structure and reasoning for its use.

(B) The utility's effort to develop and improve the methodology and inputs, including for its:

- (i) load forecast;
- (ii) forecasted impact from demand-side programs;
- (iii) cost estimates; and
- (iv) analysis of risk and uncertainty.

(28) An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following:

- (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement.
- (B) The avoided transmission capacity cost.
- (C) The avoided distribution capacity cost.
- (D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, environmental compliance costs, and transmission and distribution operation and maintenance.

(29) A summary of the utility's most recent public advisory process, including:

- (A) Key issues discussed.
- (B) How the utility responded to the issues.
- (C) A description of how stakeholder input was used in developing the IRP.

(30) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-4; filed Aug 31, 1995, 9:00 a.m.: 19 IR 20; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

## SECTION 11. 170 IAC 4-7-5 IS AMENDED TO READ AS FOLLOWS:

### 170 IAC 4-7-5 Energy and demand forecasts

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 5. (a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following:

- (1) Historical load shapes, including the following:
  - (A) Annual load shapes.
  - (B) Seasonal load shapes.
  - (C) Monthly load shapes.
  - (D) Selected weekly load shapes.
  - (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.
- (2) Disaggregation of historical data and forecasts by customer class, interruptible load, end-use where information permits.
- (3) Actual and weather normalized energy and demand levels.

- (4) A discussion of methods and processes used to weather normalize.
- (5) A minimum twenty (20) year period for peak demand and energy usage forecasts.
- (6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following:
  - (A) Total system.
  - (B) Customer classes, rate classes, or both.
  - (C) Firm wholesale power sales.
- (7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.
- (8) Justification for the selected forecasting methodology.
- (9) For purposes of subdivisions (1) and (2) of this subsection, a utility may use utility specific data or data such as described in subdivision 4(14) of this rule.
- (b) In providing at least three (3) alternative forecasts of peak demand and energy usage the utility shall include high, low, and most probable peak demand and energy use forecasts to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most likely based on alternative assumptions such as:
  - (1) Rate of change in population.
  - (2) Economic activity.
  - (3) Fuel prices, including competition.
  - (4) Price elasticity.
  - (5) Penetration of new technology.
  - (6) Demographic changes in population.
  - (7) Customer usage.
  - (8) Changes in technology.
  - (9) Behavioral factors affecting customer consumption.
  - (10) State and federal energy policies.
  - (11) State and federal environmental policies.
- (c) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, and analysis as part of the on-going efforts to improve the credibility of the load forecasting process. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-5; filed Aug 31, 1995, 9:00 a.m.: 19 IR 21; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 12. 170 IAC 4-7-6 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-6 Description of Available Resources

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 6. (a) In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the 20 year planning period being evaluated:

- (1) The net and gross dependable generating capacity of the system and each generating unit.
- (2) The expected changes to existing generating capacity, including the following:
  - (A) Retirements.
  - (B) Deratings.

- (C) Plant life extensions.
  - (D) Repowering.
  - (E) Refurbishment.
- (3) A fuel price forecast by generating unit.
- (4) The significant environmental effects, including:
- (A) air emissions;
  - (B) solid waste disposal;
  - (C) hazardous waste; and
  - (D) subsequent disposal; and
  - (E) water consumption and discharge;
- at each existing fossil fueled generating unit.
- (5) An analysis of the existing utility transmission system that includes the following:
- (A) An evaluation of the adequacy to support load growth and expected power transfers.
  - (B) An evaluation of the supply-side resource potential of actions to reduce transmission losses, congestion, and energy costs.
  - (C) An evaluation of the potential impact of demand-side resources on the transmission network.
- (6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy.

The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.

(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements:

- (1) Rate design as a resource in meeting future electric service requirements.
- (2) Demand-side resources.

For potential demand-side resources, the utility shall include the following:

- (A) A description of the potential demand-side resource, including its costs, characteristics and parameters.
  - (B) The method by which the costs, characteristics and other parameters of the demand-side resource are determined.
  - (C) The customer class or end-use, or both, affected by the demand-side resource.
  - (D) Estimated annual and lifetime energy (kWh) and demand (kW) savings
  - (E) The estimated impact of a demand side resource on the utility's load, generating capacity, and transmission and distribution requirements.
  - ~~(F)~~ Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.
- (3) Supply-side resources. For potential supply-side resources, the utility shall include the following:
- (A) Identification and description of the supply-side resource considered, including:
    - (i) Size (MW).
    - (ii) Utilized technology and fuel type.
    - (iii) Energy profile of non-dispatchable resources.
    - (iv) Additional transmission facilities necessitated by the resource.

- (B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.
- (C) A description of significant environmental effects, including the following:
  - (i) Air emissions.
  - (ii) Solid waste disposal.
  - (iii) Hazardous waste and subsequent disposal.
  - (iv) Water consumption and discharge.
- (4) Transmission facilities as a resource. In analyzing transmission resources, the utility shall include the following:
  - (A) The type of the transmission resource, including whether the resource consists of one of the following:
    - (i) new projects
    - (ii) upgrades to transmission facilities
    - (iii) efficiency improvements; or
    - (iv) smart grid technology.
  - (B) A description of the timing, types of expansion, and alternative options considered.
  - (C) The approximate cost of expected expansion and alteration of the transmission network.
  - (D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.
  - (E) A description of how:
    - (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and
    - (ii) RTO planning and implementation processes affect the IRP. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-6; filed Aug 31, 1995, 9:00 a.m.: 19 IR 22; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 13. 170 IAC 4-7-7 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-7 Selection of resources

Authority: IC 8-1-1-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 7. (a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in subsection 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.

(*Indiana Utility Regulatory Commission; 170 IAC 4-7-7; filed Aug 31, 1995, 9:00 a.m.: 19 IR 23; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 14. 170 IAC 4-7-8 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-8 Resource portfolios

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 8. (a) The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider the following:

- (1) risk;
- (2) uncertainty;
- (3) regional resources;
- (4) environmental regulations;
- (5) projections for fuel costs;
- (6) load growth uncertainty;
- (7) economic factors; and
- (8) technological change.

(b) With regard to candidate resource portfolios, the IRP must include:

- (1) An analysis of how each candidate resource portfolio performed across a wide range of potential future scenarios, including the alternative scenarios required under subsection 4(25) of this rule.
- (2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metric(s).
- (3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.

(c) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information:

- (1) A description of the utility's preferred resource portfolio.
- (2) Identification of the standards of reliability.
- (3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.
- (4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following:
  - (A) safety;
  - (B) reliability
  - (C) risk and uncertainty;
  - (D) cost effectiveness; and
  - (E) customer rate impacts.
- (5) An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, cost-effectively, and reliably meets the electric system demand taking cost, risk, and uncertainty into consideration.

~~(6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility including their impacts on the utility's transmission and distribution system for the first ten (10) years of the planning period.~~

(67) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following:

- (A) Operating and capital costs of the preferred resource portfolio.
- (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule.
- (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio.
- (D) The utility's ability to finance the preferred resource portfolio.

(78) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following:

(A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to:

- (i) environmental and other regulatory compliance;
- (ii) reasonably anticipated future regulations;
- (iii) public policy;
- (iv) fuel prices;
- (x) operating costs;
- (v) construction costs;
- (vi) resource performance;
- (vii) load requirements;
- (viii) wholesale electricity and transmission prices;
- (ix) RTO requirements; and
- (x) technological progress.

(B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.

(89) A description of the utility's workable strategy allowing it to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including to the changes in the following:

- (A) Demand for electric service.
- (B) Cost of new supply-side resources or demand-side resources.
- (C) Regulatory compliance requirements and costs.
- (D) Wholesale market conditions.
- (E) Fuel costs.
- (F) Environmental compliance costs.
- (G) Technology and associated costs and penetration.
- (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.

(919) Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-8; filed Aug 31, 1995, 9:00 a.m.: 19 IR 23; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)



SECTION 15. 170 IAC 4-7-9 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-9 Short term action plan

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 9. (a) A short term action plan shall be prepared as part of the utility's IRP, and shall cover a three (3) year period beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(c)(9), where the utility must take action or incur expenses during the three (3) year period.

(b) The short term action plan must include, but is not limited to, the following:

(1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following:

(A) The objective of the preferred resource portfolio.

(B) The criteria for measuring progress toward the objective.

(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10, 170 IAC 4-8-1 *et seq.* and consistent with the utility's longer resource planning objectives.

(3) The implementation schedule for the preferred resource portfolio.

(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.

(5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-9; filed Aug 31, 1995, 9:00 a.m.: 19 IR 24; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 16. 170 IAC 4-7-10 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-10 IRP Updates

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 10. (a) The utility may provide the director an update regarding substantial, unexpected changes that occur between IRP submissions. Copies of an update shall be provided to the OUCC and other interested parties.

(b) Upon the request of the commission or its staff, the utility shall provide updated IRP information to the director, the OUCC and interested parties. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-10*)

SECTION 17. 170 IAC 4-8-0.5 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-8-0.5 Purpose and Applicability

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-2-1; IC 8-1-8.5; IC 8-1-13; IC 23-17

Sec. 0.5. (a) The purpose of this rule is to provide the requirements for a utility's energy efficiency plan and requests for cost recovery as set forth in IC 8-1-8.5-10, and to provide the rules and procedures applicable to the implementation of utility's demand response programs and accompanying cost recovery by utilities.

(b) This rule applies to utilities as defined in this rule, unless otherwise noted. (*Indiana Utility Regulatory Commission; 170 IAC 4-8-0.5*)

SECTION 18. 170 IAC 4-8-1 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-8-1 Definitions

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-8.5;

Sec. 1. (a) The definitions in this section apply throughout this rule.

(b) "Allowance for funds used during construction" or "AFUDC" means the cost of borrowed funds used for capital expenditures associated with a utility-sponsored demand response or energy efficiency program, and a reasonable rate on other funds when so used.

(c) "Commission" means the Indiana utility regulatory commission.

(d) "Commission analysis" means the required state energy analysis developed by the commission under IC 8-1-8.5-3.

(e) "Demand-side resource" means one or more demand response programs, energy efficiency programs, or both.

(f) "Demand response" means a reduction in demand for limited intervals of time, such as during peak electricity usage or emergency conditions.

(g) "Demand response program" means a utility program designed to implement demand response.

(h) "Demand response program costs" means the direct and indirect costs of a demand response program.

(i) "DSM costs" refers to all expenses incurred by a utility in a given year for operation of a DSM program, whether the cost is capitalized or expensed. Expenses include, but are not limited to, the following:

(1) Administration.

(2) Equipment.

(3) Incentives paid to program participants.

(4) Marketing and advertising.

(5) Evaluation, measurement and verification.

(j) "Electricity supplier" has the same meaning as set forth in IC 8-1-8.5-10(a).

(k) "End-use" means the light, heat, cooling, refrigeration, motor drive, microwave energy, video or audio signal, computer processing, electrolytic process, or other useful work produced by equipment using electricity.

(~~lk~~) “Energy efficiency” means reduced energy use for a comparable or improved level of energy service.

(~~ml~~) “Energy efficiency plan” means a utility’s filing with the commission under this rule as required by IC 8-1-8.5-10(h).

(~~nm~~) “Energy efficiency program” means a utility program designed primarily to implement energy efficiency.

(~~on~~) “Energy efficiency program costs” means the direct and indirect costs of an energy efficiency program or demand response program, including, but not limited to, costs associated with EM&V, reasonable lost revenues, and reasonable financial incentives.

(~~pe~~) “Energy service” means the light, heat, motor drive, and other service for which a customer purchases electricity from the utility.

(~~qp~~) “Engineering estimate” means a calculated estimate of energy (kWh) and demand (kW) resulting from demand response program or energy efficiency program, accounting for dynamic interactions between or amount them.

(~~rq~~) “Evaluation, measurement, and verification” or “EM&V” means the independent application of methods and processes used to assess the performance of one or more energy efficiency programs, demand response programs, or both.

(~~sf~~) “Free-rider” means a customer who would have implemented demand response or energy efficiency without participating in an energy efficiency program or demand response program, yet participates in a demand response or energy efficiency program and receives an incentive or bonus for participation.

(~~ts~~) “Gross energy savings” means the change in energy consumption that results directly from the implementation of an energy efficiency program or demand response program.

(~~ue~~) “Gross demand savings” means the change in demand that results directly from the implementation of an energy efficiency program or demand response program.

(~~vh~~) “Income effect” means the short term and long term change in a customer’s energy use that is induced by a change in the amount of disposable income available to the customer resulting from savings due to the utility’s energy efficiency programs.

(~~wv~~) “Integrated resource plan”, or “IRP” means a utility’s document submitted to the commission in order to meet the requirements of 170 IAC 4-7.

(~~xw~~) “Load building” means a program intended to increase electricity consumption without regard to the timing of the increased usage.

(~~y\*~~) “Load retention” means a program intended to induce customers, that have a bona fide option of switching to alternative sources of energy services or customer owned generation, to remain as customers.

(~~zy~~) “Lost revenue” means the revenue lost, if any, less the variable operating and maintenance costs saved as a result of an energy efficiency program or demand response program.

(~~aa\*~~) “Market effects” means the indirect influence of an energy efficiency program or demand response program that results in energy and demand savings that have not been captured in EM&V activities.

(~~baa~~) “Net demand savings” means the portion of gross demand savings that is attributable to a demand response program or energy efficiency program, adjusted for free ridership and spillover.

(~~ccbb~~) “Net energy savings” means the portion of gross energy savings that is attributable to an energy efficiency program or demand response program, adjusted for free ridership and spillover.

(~~ddee~~) “Participant cost test” means a cost-effectiveness test that measures the difference between the cost incurred by a program participant and the direct economic benefit received by a program participant.

(~~eedd~~) “Participation level” means the actual number of customers participating in a specific demand-side program relative to the eligible number of customers available to participate in the program expressed as a percentage or a fraction.

(~~ffee~~) “Penetration” means the ratio of the number of a specific type of new units installed to the total number of new units installed during a given time.

(~~ggff~~) “Persistence” means the percentage of energy-saving effectiveness remaining in a particular year compared to the initial year of the measure’s installation or implementation. Persistence is a function of the following two (2) factors:

- (1) Equipment degradation.
- (2) Consumer behavior.

(~~hhgg~~) “Program Participant” means a utility customer participating in a utility-sponsored energy efficiency or demand response program.

(~~iihh~~) “Ratepayer impact measure test” or “RIM test” measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by a DSM program. It indicates the direction and magnitude of the expected change in customer bills or rate levels..

(~~jjii~~) “Rebound effect” means a specific effect where a customer responds to a lower relative cost of electric service by purchasing more electricity in the same end-use where an energy efficiency program is concentrated.

(~~kkjj~~) “Resource” means a facility, project, contract, or other mechanism used by a utility to assist in providing electric energy service to the customer.

(~~llkk~~) “Spillover” means additional reductions in energy consumption or demand by program participants beyond those directly associated with program participation.

(~~mmll~~) “Supply-side resource” means a resource that provides a supply of electrical energy or capacity, or both, to a utility. A supply-side resource includes the following:

- (1) A utility-owned generation capacity addition.
- (2) A wholesale power purchase.
- (3) A refurbishment or upgrading of an existing utility-owned generating facility.
- (4) A cogeneration facility.
- (5) A renewable resource technology.
- (6) Distributed generation.

(~~nnmm~~) “Total resource cost test” means a cost-effectiveness test that eliminates the distinction between a participant and nonparticipant by analyzing whether a resource is cost-effective based on the total cost and benefit of an energy efficiency program or demand response program, independent of the precise allocation to a shareholder, ratepayer, and participant.

(~~ooon~~) “Useful life” means the period of time the investment in a measure remains cost-effectively serviceable.

(~~ppoo~~) “Utility” means

- (1) a public, municipally owned, or cooperatively owned electric utility; or
  - (2) a joint agency created under IC 8-1-2.2;
- unless the utility is exempt under IC 8-1-8.5-7.

(~~qqpp~~) “Utility cost test” (also known as the revenue requirements test, or program administrator cost test) means a cost-effectiveness test measuring the ratio of the utility benefits to utility costs. (*Indiana Utility Regulatory Commission; 170 IAC 4-8-1; filed Aug 31, 1995, 10:00 a.m.: 19 IR 24; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA*)

SECTION 19. 170 IAC 4-8-2 IS AMENDED TO READ AS FOLLOWS

170 IAC 4-8-2 Energy Efficiency Plan Filing

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-8.5

Sec. 2. (a) An electricity supplier shall file a request for approval of an energy efficiency plan not less than one time every three years beginning no later than December 31, 2017.

(b) A utility applying to the commission for approval of its energy efficiency plan shall include the following information with its petition:

(1) A description of each energy efficiency program and demand response program proposed by the utility.

(2) A budget for the energy efficiency plan, including budgets for each energy efficiency program and demand response program.

(3) A cost-benefit analysis as required by IC 8-1-8.5-10(j)(2) using one or more of the following tests:

(A) Participant cost test.

(B) Ratepayer impact measure.

(C) Utility Cost.

(D) Total Resource Cost.

(E) Other reasonable tests accepted by the commission.

A utility is not required to express a test result in a specific format, however, results must include the total costs and total benefits used in each calculation and the benefit-cost ratio for the specific test.

(4) Projected changes in customer consumption of electricity resulting from the implementation of the energy efficiency plan.

(5) A statement of whether the energy efficiency plan is consistent with the Ceommission analysis.

(6) A description of how the energy efficiency plan is consistent with the utility’s most recent IRP, including copies of relevant portions of the utility’s most recent IRP.

(7) Identification of any preference to any customer class potentially resulting from implementation of an energy efficiency program or demand response program.

(8) A description of the lost revenues and financial incentives the utility seeks to recover.

(9) The effect, or potential effect, in both the long term and the short term, of the energy efficiency plan on the electric rates and bills of program participants compared to the electric rates and bills of customers that do not participate in the program.

(10) An EM&V procedure, ~~complying with section 4 of this rule,~~ to assess implementation and quantify the impact on energy and demand of each energy efficiency program and demand response program included in the energy efficiency plan.

(11) A statement of the utility's energy efficiency goals for producing reasonably achievable energy efficiency through implementation of cost effective energy efficiency programs. The energy efficiency goals shall be designed to achieve an optimal balance of energy resources in an electricity supplier's service territory. The energy efficiency goals shall exclude industrial customers that have opted out of the utility's energy efficiency plan.

(12) If an electricity supplier is using forecasted costs and energy saving for cost recovery purposes, it shall propose a mechanism to reconcile forecasted costs and energy savings with actual costs and energy savings.

(13) The work papers and data used for calculation of the test performed under subsections 3, ~~8~~, and 9 of this section, and the calculations performed under subsection 8.

(c) An electricity supplier may submit a plan required under this section either as an independent proceeding or as part of a general base rate proceeding.

(d) At the same time an electricity supplier petitions the commission under IC 8-1-8.5-10(h), the electricity supplier shall:

(1) provide a copy of the petition and plan to the Indiana office of utility consumer counselor; and

(2) post a copy of the petition and plan on the electricity supplier's internet website.

The electricity supplier may redact confidential or proprietary information.

SECTION 20. 170 IAC 4-8-3 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-8-3 Home Energy Efficiency Assistance Programs

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 3. (a) The commission may approve a home energy efficiency assistance program as part of an energy efficiency plan, approved in its entirety or in part, whether or not the home energy efficiency assistance program is cost effective as analyzed in accordance with subsection 2(b) of this rule or as determined by the commission.

(b) The commission shall not approve financial incentives for a home energy efficiency assistance program that is not cost effective. (*Indiana Utility Regulatory Commission; 170 IAC 4-8-3; filed Aug 31, 1995, 10:00 a.m.: 19 IR 27; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA*)

SECTION 21. 170 IAC 4-8-4 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-8-4 Evaluation, Measurement and Verification Plan

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-8.5

Sec. 4. (a). The utility's proposed energy efficiency plan submitted to the commission under 170 IAC 4-8-2 must include proposed EM&V procedures, but the utility's EM&V plan may be finalized and submitted at a later date. The EM&V plan must include the following for each energy efficiency program and demand response program in the utility's energy efficiency plan:

- (1) The type and timing of the measurement activity.
- (2) The process used to modify the impact estimate for future planning and design of the program.
- (3) The utility's evaluation procedure. The utility must include information on how it will collect data to determine:
  - (A) load impact;
  - (B) participation level;
  - (C) utility cost and benefits;
  - (D) participant cost and benefits;
  - (E) net energy program savings;
  - (F) net demand program saving;
  - (G) useful life; and
  - (H) persistence.
- (4) The actions the utility will take to measure the effectiveness of the programs.:
  - ~~(A) optimize market penetration of the program;~~
  - ~~(B) minimize free-riders; and~~
  - ~~(C) measure spillover.~~
- (5) A comparison of usage and demand patterns of similar participant and nonparticipant groups, through the use of customer bill analysis, engineering estimates, end-use meter data, or other methods. The comparison must identify the impacts of program participation on:
  - (A) gross energy;
  - (B) gross demand;
  - (C) net energy; and
  - (D) net demand.

(6) A method to measure rebound effect and the income effect for an energy efficiency program and demand response program where the effect may be significant.

(b) The utility shall submit its proposed EM&V procedures with its proposed energy efficiency plan. However, the utility may submit its EM&V plan subsequent to its energy efficiency plan filing. In addition to the EM&V plan submitted to the commission under this section, a utility shall submit to the commission and post to the utility's website, annually, a document containing information, data, and results from the utility's EM&V activities, including its load impact evaluation studies.

*(Indiana Utility Regulatory Commission; 170 IAC 4-8-4; filed Aug 31, 1995, 10:00 a.m.: 19 IR 27; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)*

SECTION 22. 170 IAC 4-8-5 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-8-5 Cost recovery

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-8.5

Sec. 5. (a) The commission shall approve the recovery of reasonable energy efficiency program costs and may approve the recovery of reasonable demand response program costs on a timely basis through a periodic rate adjustment mechanism.

(b) The commission shall limit the periodic rate adjustment mechanism to the incremental energy efficiency program costs or demand response program costs, or both, not already included in the utility's base rates, if applicable.

(c) Nothing in this rule precludes a utility from requesting or the commission from approving in a rate case the following:

(1) The inclusion of the energy efficiency program costs or demand response program costs, or both, in the utility's base rates using a balancing account, where appropriate, to reconcile the utility's recovered expenditures.

(2) The inclusion of the capital cost, with accumulated AFUDC, in the utility's rate base, amortized over a period set by the commission.

(3) The accumulation, with a carrying charge, of the non-capital cost incurred and not otherwise recovered through the utility's base rates or through periodic adjustments in a deferred account to be amortized over a period set by the commission.

(d) Recovery of energy efficiency program costs or demand response program costs, or both, under this section shall continue as determined by the commission provided that the utility maintains satisfactory EM&V activities as specified in section 4 of this rule.

(e) In order to ensure that energy efficiency program and demand response program benefits and costs are allocated between utility shareholders, participants, and nonparticipants in a fair and economical way, the utility must demonstrate to the commission that a customer incentive paid by the utility for participation, when combined with the reduction in the participant's utility bills:

(1) reflects the net benefit of the energy efficiency or demand response program to the utility and all customers; and

(2) minimizes cross-subsidies between customer groups and between program participants and nonparticipants within a customer group.

*(Indiana Utility Regulatory Commission; 170 IAC 4-8-5; filed Aug 31, 1995, 10:00 a.m.: 19 IR 27; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)*

## SECTION 23. 170 IAC 4-8-6 IS AMENDED TO READ AS FOLLOWS

### 170 IAC 4-8-6 Lost revenue

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-8.5

Sec. 6. (a) The commission shall approve the recovery of reasonable lost revenues for energy efficiency programs and may approve the recovery of reasonable lost revenues for demand response programs.

(b) A utility seeking recovery of lost revenue shall propose for commission review a methodology or process for calculating lost revenue that accounts for the following:

(1) The impact of free-riders.

(2) Spillover.

(3) The change in the number of program participants between base rate changes

(4) A revised estimate of the energy efficiency program's and demand response program's specific load impact resulting from the utility's EM&V activities.



(c) Nothing in this rule precludes a utility from proposing an alternative regulatory plan that eliminates the disincentive to pursue an energy efficiency program or demand response program in lieu of recovery of the utility's reasonable lost revenues. If the commission approves a utility's proposed alternative regulatory plan in a manner that eliminates the utility's disincentive to implement an energy efficiency or demand response program, lost revenue recovery shall not be approved. (*Indiana Utility Regulatory Commission; 170 IAC 4-8-6; filed Aug 31, 1995, 10:00 a.m.: 19 IR 28; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA*)

SECTION 24. 170 IAC 4-8-7 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-8-7 Financial incentives

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-8.5

Sec. 7. (a) A utility may propose a financial incentive based on particular attributes of an energy efficiency program or demand response program and the program's desired results. A financial incentive may include, but is not limited to, the following:

- (1) Granting a utility a percentage share of the net benefit attributable to an energy efficiency program or demand response program.
  - (2) Allowing a utility to earn a greater than normal return on equity for a rate based energy efficiency program or demand response program costs.
  - (3) Adjusting a utility's overall return on equity in response to quantitative or qualitative evaluation of an energy efficiency program's or demand response program's performance.
- (b) The commission may terminate, when appropriate, a financial incentive.
- (c) A financial incentive shall not provide an incentive payment for an energy efficiency program or demand response program unless the net kilowatt or kilowatt-hour impact, or both, can be reasonably determined.
- (d) Load building and load retention programs are not eligible for performance incentives.
- (e) A financial incentive must reflect the value to the utility's customers of the supply-side resource cost avoided or deferred by the utility's energy efficiency program or demand response program minus the incurred utility program costs.
- (f) In order to reflect only the energy efficiency and demand impact of an energy efficiency program or demand response program, the financial incentive must exclude the effect of free-riders from the incentive calculation.
- (g) A financial incentive may be based on forecasted demand and energy savings until the information on demand and energy savings from the utility's EM&V activities becomes available. (*Indiana Utility Regulatory Commission; 170 IAC 4-8-7; filed Aug 31, 1995, 10:00 a.m.: 19 IR 28; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA*)

SECTION 25. 170 IAC 4-8-7.5 IS AMENDED TO READ AS FOLLOWS

170 IAC 4-8-7.5 Industrial Customer Opt Out of Participation in Energy Efficiency Plan

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-8.5

Sec. 7.5. (a) An industrial customer (as defined in IC 8-1-8.5-9(e)) may opt out of an electricity supplier's energy efficiency plan under this section by following the procedure set forth in IC 8-1-8.5-9(f) and 9(g).

(b) The opt out of an industrial customer who has previously complied with the procedure set forth in IC 8-1-8.5-9(f) constitutes an opt out of an electricity supplier's energy efficiency plan under this section.

(c) An industrial customer may follow the procedure set forth in IC 8-1-8.5-9(g) to opt back in to an electricity supplier's energy efficiency plan.

SECTION 26. 170 IAC 4-8-8 IS AMENDED TO READ AS FOLLOWS

170 IAC 4-8-8 Impact of demand-side management on small business

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-8.5

Sec. 8. Contemporaneously with the commission's approval of a utility's petition under this rule, the commission shall, under 16 U.S.C. 2621(c)(3)(A) and 16 U.S.C. 2621(c)(3)(B) effective October 23, 1992, do the following:

(1) Consider the impact that implementation of the proposed energy efficiency or demand response program would have on small business.

(2) If necessary, implement a revision to the proposed energy efficiency program or demand response program to assure that utility actions would not provide the utility with an unfair competitive advantage over small business.

*(Indiana Utility Regulatory Commission; 170 IAC 4-8-8; filed Aug 31, 1995, 10:00 a.m.: 19 IR 29; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)*