

ENERGY INDEPENDENCE AND SECURITY ACT OF 2007

New PURPA Standards (16-19)

Policy Statement of

SOUTHEASTERN IN REMC

INTRODUCTION

The Energy Independence and Security Act of 2007 proposes changes to the Public Utility Regulatory Policy Act (“PURPA”) by adding four new Standards dealing with integrated resource planning, rate design modifications to promote energy efficiency investments, consideration of smart grid investments, and smart grid information. The following represents Policy Statements on behalf of Southeastern IN REMC pertaining to the new PURPA Standards.

Implementation of the new Standards is structured as follows:

- A. State regulatory authorities for the utilities whose rates they regulate are required to consider these new federal Standards.
- B. Nonregulated utilities with annual retail sales greater than 500 million kWh's are required to consider the new federal Standards.
- C. Sales of electric energy for purposes of resale are excluded.

As a retail supplier, Southeastern IN REMC is not exempt from the federal Standards due to sales for retail consumers exceeding 500 million kWh's. Southeastern IN REMC also recognizes that even though the Standards themselves are written as if they are mandatory, PURPA only requires that the Standards be considered. Southeastern IN REMC broadly supports the stated goals of the PURPA amendments to promote energy conservation, resource efficiencies, smart grid investment and equitable rates to electric consumers, and will consider them in the context of the policy statements herein.

I. INTEGRATED RESOURCE PLANNING (STANDARD 16)

[Policy Framework and Discussion](#)

Adoption of PURPA Standard (16), Integrated Resource Planning (IRP), would require that each electric utility engage in a comprehensive planning process intended to systematically consider appropriate supply and demand resources to meet current and future load requirements within the context of local, state, and federal policy goals and objectives. While the IRP process has

many facets and objectives, the purpose of this Standard is to address integrating energy efficiency into utility plans and adopting policies that encourage cost-effective energy efficiency. For purposes of this Standard, the term “energy efficiency” means efforts that allow consumers to use less energy without altering their behavior, for example, through increased deployment of newer technologies or replacement of existing energy-consuming devices with newer version that accomplish the same tasks while consuming less energy.

Indiana Administrative Code 170 IAC 4-7-3 requires that Hoosier Energy, wholesale power supplier to Southeastern IN REMC, submit an IRP to the Indiana Utility Regulatory Commission on a biennial basis. The Code provides specific guidelines and requirements that must be followed in the IRP. On February 25, 2009 the IURC instigated proceeding (Cause No. 43643) to investigate and review the sufficiency of the IRP rule and its guidelines and requirements. That proceeding is ongoing.

To comply with the Indiana Administrative Code, Hoosier Energy submits an IRP to the Indiana Utility Regulatory Commission biennially. The IRP is prepared in conjunction with all members of Hoosier Energy including Southeastern IN REMC and the process generally involves the following tasks:

1. Every two years, Hoosier Energy develops in conjunction with its member systems, including Southeastern IN REMC, a long range Power Requirements Study (PRS) that uses econometric forecasting methods prescribed by the Rural Utility Service (RUS) to project future energy and capacity load requirements for the next 20 years for each member and for each class of residential, commercial and industrial customers. These individual member system forecasts are aggregated to form the Hoosier Energy forecast. Sensitivities are performed to get a range of projected requirements for various economic circumstances.
2. A list of potential supply-side energy resources, including renewable energy resources, is prepared which includes the technical, operational, economic, and risk characteristics of each as well as cost and operational parameters which are generally drawn from research of publicly available data such as the Electric Power Research Institute or particular studies Hoosier Energy consultants may have performed on a more regional or technology specific basis. The supply side options include traditional self build options, purchased power options, partnership or joint-ownership options, renewable resource options, and energy available through the MISO market. This information on supply side options is used to develop avoided costs for electric generation capacity to perform cost effectiveness screening for energy efficiency and demand response programs. In addition to cost profiles, social and environmental programs, policies and risks are also given consideration as part of the feasibility assessments.
3. Demand Side Management (DSM) and Energy Efficiency measures are then considered, and with the most recent IRP being developed, a more detailed and extensive analytical process has been used. DSM and energy efficiency have been analyzed on technical potential, technical potential restricted to economic justification, and an achievable level of programs limited by reasonable budgets and resources and customer acceptance estimates. After establishing appropriate baseline measures, DSM and energy efficiency

options are measured and are analyzed based on per unit energy and demand savings, costs, lifetimes and costs of conserved energy and demand. Benefit-cost analyses are then performed considering avoided costs, utility rebates or incentives to measure the present value of the energy and demand savings over the life of the particular measure.

4. Periodically, market research of end-use members is performed to assist in the development of consumer sentiments and program acceptance, market penetration levels of existing programs, and profiles of appliances and building characteristics for potential energy efficiency opportunities.
5. The energy efficiency and DSM programs are incorporated into the PRS for determining future supply side resources.
6. Various models are used from this point in conjunction with a base set of assumptions of fuel prices, inflation, and cost of capital generally taken from published reports such as the Annual Energy Outlook or various government publications. The modeling will select various supply options that will optimize the mix of resources to the load characteristics and projected requirements of the members through the PRS on a least cost, risk-adjusted basis. To address risk, the IRP will generally assess exposure to various risks such as technological, environmental, financial, construction and market price volatilities.

Policy Statement

Hoosier Energy, in conjunction with Southeastern IN REMC, will continue to develop its biennial IRP in accordance with the rules and regulations of the Indiana Utility Regulatory Commission and as set forth in the policy framework and discussion. This process will continue to involve all member systems of Hoosier Energy in all stages of the process. Hoosier Energy and Southeastern IN REMC will also continue to consider, analyze and emphasize the benefits and costs of DSM and energy efficiency programs in the IRP planning process.

II. RATE DESIGN MODIFICATIONS TO PROMOTE ENERGY EFFICIENCY INVESTMENTS (STANDARD 17)

Policy Framework and Discussion

Section 532 of EISA amends PURPA 111(d)(17) by adding a new Standard that requires consideration of “Rate Design Modifications to Promote Energy Efficiency Investments”.

The statute states “rates allowed to be charged by any electric utility shall align utility incentives with the delivery of cost effective energy efficiency and promote energy efficiency investments.” The statute identifies six policy options to consider including:

- (i) Removing the “throughput” incentive and other regulatory and management disincentives to energy efficiency. This option refers to the link between a utility’s sales and earnings. Generally, an increase in sales means an increase in earnings because fixed costs and profit or margins are typically recovered in a per unit (kWh) segment of the rate. A sales decrease from efficiency programs could lead to decreased earnings and might lead to an inability to recover some fixed costs. These outcomes may create impediments to offering or encouraging consumer participation in programs that decrease electricity consumption.
- (ii) Providing utility incentives for the successful management of energy efficiency programs. If efficiency programs have a negative impact on earnings or margins, any program the utility is required to provide could be undermined by financial disincentives that negate the incentive to pursue implementation of the programs.
- (iii) Including the impact of adoption of energy efficiency as one of the goals of retail rate design, recognizing that efficiency must be balanced with other objectives. This option asks that state commissions and utilities consider efficiency as one of several goals in retail rate design (along with quality of service, safety, reliability, just and reasonable rates, etc.). For example, nonregulated utilities might consider making energy efficiency a specific goal in the tariff and rate design process.
- (iv) Adopting rate designs that encourage energy efficiency for each customer class. Not all customer classes may respond in the same manner to efficiency programs suggesting different programs may need to be developed for different classes.
- (v) Allowing timely recovery of energy efficiency related costs. Uncertainty about recovery of efficiency program costs and the timing of recovery can create additional obstacles to utility’s offering or encouraging consumer participation in efficiency programs.
- (vi) Offering home energy audits, demand response programs, publicizing the financial and environmental benefits associated with home efficiency improvements, and educating homeowners about existing Federal and State incentives, including low cost loans, that make efficiency improvements more affordable.

Standard 17 reflects concerns that standard ratemaking practices may not encourage, and may discourage, utilities from adopting energy conservation or efficiency measures because those measures could lead to reduced earnings for investor owned utilities or reduced margins for cooperatives. If sales decline too much, the utility may be unable to recover all fixed costs since monthly fixed charges (i.e. the “customer or access charge”) are often insufficient to recover all fixed costs.

Some states have responded by decoupling investor owned utility earnings from electricity sales or use other means to modify rate designs. Other states have considered means to not only remove disincentives but to offer incentives to utilities to develop and administer efficiency programs while others have considered outsourcing those programs to third party providers. The

National Action Plan for Energy Efficiency organizes these and other state approaches into three broad categories including:

1. Allowing the direct costs of efficiency programs to be recovered by the utility, typically through rate cases, a “system benefits charge” or a tariff rider/surcharge.
2. Recovery of fixed costs through a “lost revenue adjustment mechanism” in which the utility is compensated for sales decreases related to efficiency programs. “Decoupling” among investor owned utilities is an example of this approach and about 30 states have implemented or considered decoupling plans for gas or electric utilities. Decoupling has been described as a tracking mechanism that allows utilities to automatically adjust rates and revenues whenever sales deviate from targeted levels or baselines. The mechanism reduces uncertainty about the timing of cost recovery by eliminating the need for traditional rate cases, subject to certain tests, and may allow utilities to keep earnings near authorized levels. Decoupling is often controversial. Opponents suggest utilities are not, and should not be, guaranteed earnings if sales decline; the approach shifts too much risk from utilities and stockholders to consumers; rate cases are a better way to adjust revenues; and decoupling isn’t really needed to encourage efficiency programs.
3. Providing performance incentives to utilities for participation in efficiency programs. The general intent of these programs has been described as an effort to put energy efficiency on the same footing as other supply options; that is to make them profitable and not just a break even activity. Examples include performance target incentives, shared savings incentives and rate of return adders.

Another approach being considered by some utilities is to increase the fixed monthly access or customer charge until it recovers all fixed costs of serving consumers. If that is accomplished, the “throughput” rate need only recover the variable cost of service and reductions in energy consumption are less likely to undermine recovery of fixed costs or margins. Other tariff and rate options that have been considered by states to encourage efficiency include inclining block rate structures in which rates increase as consumption increases, and time-based rates including on-peak/off-peak pricing and “dynamic” rates such as critical peak pricing or real time (hourly) pricing.

SOUTHEASTERN IN REMC and HOOSIER ENERGY (G&T) Activities

Southeastern IN REMC and Hoosier Energy have long supported end-use energy efficiency measures among all customer classes. Southeastern IN REMC and the G&T spent millions of dollars over two decades to provide incentives to promote end-use member selection of higher efficiency water heating and HVAC units, develop and support the Touchstone Energy Home program to promote construction of higher efficiency housing, provide energy audits among residential and commercial/industrial end-use members, and provide end-use member education programs including publications, web based

information and annual seminars promoting building and HVAC improvements. The G&T and members have also provided rate incentives to encourage load shifting through guaranteed off-peak periods and interruptible service and rate options for commercial and industrial members. Recent additional demand response options available to G&T members include an updated Interruptible Power Tariff, a Distributed Generation Purchase Tariff, a Standby Service Rider that provides grid access to end-use members that self-generate, and a Voluntary Curtailment Rider in which end-use members may be paid to reduce load in high-demand periods upon request from their G & T power supplier. A range of contract proposals to provide additional demand response options to large power end-use members have also been considered.

Member and G&T emphasis and focus on demand side management (DSM) programs expanded greatly in 2008 and 2009. Energy efficiency and demand response programs were developed with member systems with a stated goal of empowering end-use members to better manage energy consumption and expenditures in a period of rising costs. The Hoosier Energy Board of Directors adopted a Demand Side Management policy in 2008 that established a goal of reducing peak demand and energy consumption among participating cooperatives by 5% below levels that would otherwise be experienced by 2018. Budget authority to support DSM programs was approved by the Board in 2008 and 2009 and funding is expected to sustain a long term DSM effort. Funding is provided through base rates with recovery of DSM related variable costs through a tracker.

Additional staff assigned to DSM development were hired at Hoosier Energy in 2008 and program options were evaluated after completion of an extensive technical and economic feasibility assessment with Summit Blue and GDS Consultants. Comprehensive on-site audits were completed at more than 400 residential and commercial/industrial facilities to collect data for the assessment process. Resulting programs launched in 2009 include:

1. Revised and increased incentives to encourage end-use members to select higher efficiency heating, cooling and water heating technologies. Higher efficiency units receive greater incentives than lower efficiency units, and new incentives were added to promote dual fuel HVAC systems and higher efficiency central air conditioning units. Programs were created to offer significant incentives for replacement of electric furnaces with air source or ground source heat pumps.
2. A compact fluorescent light (CFL) distribution program was launched with members in 2009. To date, more than 300,000 bulbs have been distributed through member systems at no cost to end-use members. Model results suggest bulbs will reduce demand by approximately 1.2 MW, reduce energy consumption by approximately 13,000 MWH annually, and eliminate 13,000 tons of carbon dioxide emissions.
3. A residential load control pilot program was launched in 2009 to test control system capabilities using four communications technologies. Initial tests include approximately 750 control units on water heaters and central air conditioners at locations across southern Indiana. A full rollout of residential load control for water heaters and air conditioners is planned for April 1,

2010. Consumer recruitment and switch installation is expected to require significant time, but the program has a long term planning horizon. Several cooperative Members and Hoosier Energy are jointly pursuing a federal “Smart Grid” grant to help support broader program implementation.

4. Members and Hoosier Energy will launch an “Appliance Round-up” pilot program in 2009. The purpose of the pilot is to test methods to encourage end-use members to retire older, less efficient refrigerators or freezers with a target of retiring 400 units in 2009. More than 30% of end-use member households report multiple refrigerators/freezers (there were 10 refrigerators at one surveyed home).
5. A commercial and industrial efficiency program was launched in May of 2009. The program offers incentives to larger end-use members to encourage installation and upgrade of interior lighting, motors and improvements in building shells. Meetings were completed in the first 45 days of the program with more than 100 large power end-use members to introduce and discuss program features. Three projects were approved in the first 30 days of the program and an additional three projects are now under consideration.
6. Members and the G&T launched a home weatherization pilot program in 2009 that targets weatherizing 50 homes in a 12-month period. Program goal is to reduce energy consumption by 20% to 30% in participating households and determine the feasibility and scope of a broader future program. Measures include duct and crack sealing, insulation installation, low flow showerheads and faucets, installation of CFL and other measures as may be needed. Pre and post weatherization audits will be completed to confirm estimated savings. Hoosier Energy was also recently selected to receive a \$5.1 million stimulus fund grant from the State of Indiana to weatherize more than 800 homes in 13 Indiana counties.

Member systems and Hoosier Energy devoted significant effort in 2008 to review and evaluation of new wholesale tariff options with extensive support from GDS Consultants. The degree and capability of tariff options to support DSM initiatives was a driving factor in the process and resulting tariffs represent a significant departure from traditional G&T rates. Tariffs were approved by the Hoosier Energy Board in March, 2009 for implementation on April 1, 2010.

Key features of new tariffs include:

1. Production demand charges currently based upon twelve monthly system coincident peak intervals (CP) are eliminated. Production demand in new tariffs will be based upon CP in the three peak summer months of June, July and August with production demand in the following three months based upon average demand during peak months. Production demand in winter peak months of December, January and February will be based upon actual CP load with production demand in the following three months based upon average demand in winter peak months (see Attachment A). This change increases the value of residential load control to member systems and consumers and supports more accurate reflection of peak and off-peak periods for ratemaking.

2. The current production demand charge is the same in all months of the year. That provision is eliminated and replaced with new seasonal demand charges with summer demand charges about 40% higher than winter demand charges. This change reflects the market reality that summer demand or capacity costs are higher than winter costs, and that pressure to add future capacity is driven by summer rather than winter peak demands (see Attachment A).
3. A new tariff provision restricts Hoosier Energy to billing members for CP demand in peak months only when a load control signal has been provided.
4. The current flat energy charge billed for all kWh is eliminated in new tariffs and replaced with on-peak and off-peak charges. Approximately 88% of all annual hours are defined as off-peak in new tariffs. On-peak wholesale energy rates are approximately 90% higher than off-peak rates (see Attachment B).
5. Technical and cost allocation adjustments were made in transmission and radial line/substation demand charges to better reflect cost causation.
6. Two additional tariffs were created to provide the option of delivery at transmission voltages (69kV and 138/161kV) to end-use members that prefer to own and maintain radial lines and substations.

Policy Statement

Southeastern IN REMC and Hoosier Energy are committed to developing and offering effective demand side management programs to end-use members, including both demand response and efficiency measures, and providing rates that support end-use member adoption of Demand Side Management (DSM) options. Southeastern IN REMC and the G&T consciously decided to treat DSM as an equivalent resource to new generation with a long-term intent to meet future needs through whichever option offers the lowest cost for end-use members. Program costs are significant, and there is potential for revenue erosion, but coop system members chose to proceed with wholesale tariff changes to support DSM efforts.

Southeastern IN REMC and Hoosier Energy undertook these initiatives to position end-use members to better manage rising energy costs and because DSM can offer long term savings compared to other supply alternatives. These programs have been launched and will continue to evolve in the absence of a State or Federal mandate or new PURPA Standard. The Southeastern IN REMC Board has selected GDS Consultants to perform a Cost of Service Study and prepare new rate designs to become effective April 1, 2010 which incorporate the above findings.

New - Standard Tariff Production Demand

Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May

Proposed (Control Periods, 7 a.m. to 11 p.m., E.S.T.)

Summer

1-CP 1-CP 1-CP

Billing kW

Act Act Act Avg Avg Avg

Winter

1-CP 1-CP 1-CP

Billing kW

Act Act Act Avg Avg Avg

New - Standard Tariff Energy TOU Periods

Item	Hour-Ending																							
Time (AM/PM)	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
Time (Military)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer Weekday																								
Summer Weekend	← All Off-Peak →																							
Winter Weekday																								
Winter Weekend	← All Off-Peak →																							
Valley Weekday	← All Off-Peak →																							
Valley Weekend	← All Off-Peak →																							

Summer -- June through August
 Winter -- December through February
 Valley -- March through May and September through November

"On-Peak periods" illustrated in blue shading

Special Note: Demand "on-peak" period remain as -- "On-peak" is between 7 a.m. and 11 p.m. year-round.

Interpretation of above chart defined "on-peak" periods
 Summer Weekday "on-peak" period is between 11 am and 9 pm.
 Winter Weekday "on-peak" period is between 7 am and 10 am, and between 6 pm and 9 pm.

III. CONSIDERATION OF SMART GRID INVESTMENTS (STANDARD 18)

Policy Framework and Discussion

The Energy Independence and Security Act of 2007 amends PURPA by adding Standard 18 titled “State Consideration of Smart Grid Investments” stating that “Each State shall consider requiring that, prior to undertaking investments in non-advanced grid technologies, an electric utility of the State demonstrate that the electric utility considered an investment in a qualified smart grid system based on appropriate factors, including

- (i) total costs;
- (ii) cost-effectiveness;
- (iii) improved reliability;
- (iv) security;
- (v) system performance; and
- (vi) societal benefit.”

The thrust of this Standard is to require utilities to consider investing in smart grid technologies before investing in traditional transmission and distribution systems. Other components of the Standard deal with establishing ratemaking rules which do not discourage smart grid investment by allowing fair cost recovery and treatment of equipment obsolescence so as not to make stranded cost an impediment to Smart Grid investment.

The Smart Grid is not well defined but is beneficially vague so as not to restrict innovation and opportunity. One informal definition calls it “a transformed electricity transmission and distribution network or “grid” that uses robust two-way communications, advanced sensors, and distributed computers to improve the efficiency, reliability and safety of power (generation), delivery and use” (Wikipedia: 2008).

The Department of Energy (DOE) itemizes seven characteristics or functions that denote Smart Grid investment. These include:

1. Enabling active participation by end-use members
2. Accommodating all generation and storage options
3. Enabling new products, services, and markets
4. Optimizing assets and operating efficiently
5. Anticipating and responding to system disturbances in a self-healing manner
6. Operating resiliently against physical and cyber attack and natural disasters
7. Providing the power quality for the range of needs in a digital economy

Some basic components of Smart Grid investment could include smart appliances or thermostats, advance meter infrastructure (AMI), transmission and distribution automation equipment, and digital communications technology. Hoosier Energy and Southeastern IN REMC are and have been investing in the normal course of

business, and as need and economics dictate, in capital equipment that qualifies under these categories. At this point in time, nearly 56% of the Power Network consumers, including end-use members of Southeastern IN REMC, are served by distribution cooperatives that installed some form of AMI or AMR (Automated Meter Reading) technology. As well, over 44% of Hoosier Energy's member distribution cooperatives have employed or are deploying a SCADA (Supervisory Control and Data Acquisition) system to aid in information, reliability and security. Hoosier Energy has employed SCADA for many years and maintains a system of radio controlled switches in addition to automated transmission line breakers for quick sectionalizing of lines during outage conditions. Hoosier Energy recently upgraded its microwave system from analog to digital to improve the quality and quantity of data that can be exchanged.

Additionally, member system interest in end consumer devices such as load management switches, pre-paid metering and improved on-line distribution automation match up well with the Smart Grid evolution.

Policy Statement

How the smart grid is built will vary broadly among the Hoosier Energy member systems. There is no one smart grid and no two utilities (or cooperatives) are likely to implement the smart grid in the same manner since local needs vary and a multitude of options are available. Hoosier Energy will continue to consider various smart grid options as it maintains and improves its system. The G&T will balance the benefits of implementing various smart grid options with costs to the consumers. Hoosier Energy will continue to work closely with Southeastern IN REMC to provide assistance in this area. Each member system will need to make smart grid choices based upon a range of options and issues including local matters such as the legacy system, customer density, customer preferences, etc. Hoosier Energy and Southeastern IN REMC need to carefully develop smart grid goals taking into consideration the technology that accomplishes the goals, time frame for implementation, risks of rendering parts of the system obsolete when changes are made, cost and cost recovery.

Southeastern IN REMC is initiating a pre-pay meter system in mid 2009 which uses the infrastructure of the automated meter reading (AMR) system. The AMR system is capable of providing time of use meter information for billing purposes. Southeastern IN REMC has installed SCADA at some substations and will continue to implement SCADA at additional substations in the future.

IV. SMART GRID INFORMATION (STANDARD 19)

Policy Framework and Discussion

This Standard "asks that states consider providing electricity purchasers with access to information concerning pricing, usage, intervals, and sources, either in writing or in electronic form." It requires utilities to consider providing electric purchasers with direct access to information concerning pricing, usage, intervals, and sources of energy either in writing or electronic form. This can be accomplished by providing access to smart meters and bi-directional communications methods and opportunities to offer time-of-use (TOU) pricing, critical peak pricing, and real time pricing. The Hoosier Energy Power Network has endorsed this direction through the adoption of new tariffs that

include seasonal demand and TOU pricing. The seasonal demand rate sets up differentiated summer and winter demand charges as well as offering incentives to remove load from the peak summer (June – August) and peak winter (December – February) months. TOU pricing is achieved by use of an on-peak and an off-peak energy rate. This two tiered energy rate provides an on-peak period for both summer and winter months with the remaining designated as off-peak.

Policy Statement

Hoosier Energy will continue to examine various methods of providing smart grid information to member systems including Southeastern IN REMC, balancing member system preferences regarding types of information with the costs of implementing, operating and maintaining systems necessary to provide that information. Methods will be judged by a cost benefit analysis to determine which options make the most sense.

Southeastern IN REMC will continue to work with Hoosier Energy to assist in providing smart grid information to end-use members as technology and member needs and preferences warrant, balancing carefully the costs of capital investments in processes and operational costs and impact of recovering those costs in retail rates.