**STATE OF NEW HAMPSHIRE**
**PUBLIC UTILITIES COMMISSION**

**DE 06-061**

**INVESTIGATION INTO**
**IMPLEMENTATION OF THE ENERGY POLICY ACT OF 2005**

**Order Regarding the Adoption of Standards for**

**Time-Based Metering and Interconnection**

**O R D E R N O. 24,763**

**June 22, 2007**

## I. INTRODUCTION AND PROCEDURAL HISTORY

This proceeding before the New Hampshire Public Utilities Commission (Commission) concerns certain electricity-related responsibilities allocated by Congress to the states in the Energy Policy Act of 2005, Public Law No. 109-58, 119 Stat. 594 (2005). Specifically, by certain amendments to the Public Utility Regulatory Policies Act (PURPA), the 2005 legislation requires state utility commissions to make specific determinations as to whether to implement congressionally approved standards concerning net metering, diversity of fuel sources, fossil fuel generation efficiency, time-based (sometimes referred to as "smart") metering (including the time schedule for the applicable rates), and interconnecting generation facilities on customer premises with the grid.[1] This order comprises the Commission's determinations with respect to the last two standards.[2]

The 2005 Act requires each state commission to have commenced its investigation of smart metering no later than August 8, 2006, and to make a final determination no later than

[1] The five new standards are codified as 16 USC § 2601(d)(11), (12), (13), (14) and (15).
[2] Congress gave state commissions until two years after enactment, or August 8, 2007, to begin consideration of the first three standards (net metering, fuel diversity and fossil fuel generation efficiency). The statutory deadline to complete consideration of those standards is August 8, 2008.

August 8, 2007. The Act also provides that no consideration is necessary if within the three years preceding the 2005 legislation, (a) the state has already implemented the federal smart metering standard or one comparable to it, (b) the state regulatory authority (or, in the case of an unregulated utility, the utility itself) has already considered such a standard within that period, or (c) the state legislature has voted on the implementation of such a standard." 16 U.S.C. § 2622(e).

With respect to smart metering, Congress directed each state regulatory authority to conduct an investigation and determine whether it is appropriate for the state's electric utilities "to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs." 16 U.S.C. § 2625(i). The federal standard adopted in the 2005 Act would require each electric utility to

> offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

16 U.S.C. § 2621(d)(14)(A). The statute goes on to identify four specific types of time-based pricing structures: time-of-use pricing, critical peak pricing, real-time pricing and load reduction agreements for large customers. *Id*. at (d)(14)(B).

Time-of-use rates typically include fixed kilowatt-hour (kWh) charges that vary by season and time-of-day based on the utility's cost of generating and/or purchasing electricity at wholesale. Seasonal time-of-use prices can be implemented using traditional electromagnetic meters, which most small customers rely on. Time-of-day pricing, however, requires an electronic interval meter.

Critical peak pricing is essentially time-of-use pricing with a dynamic component added that flows through prices in real-time during “critical peak” periods. Critical peak pricing is used to alert electricity customers that energy usage during certain critical periods, such as hot summer days when air-conditioning loads peak, can cause increased transmission congestion and reduced system reliability. To implement critical peak pricing, participating customers must have electronic interval meters with related telecommunications capability that allows the utility to notify customers when the critical peak period is in effect and to retrieve the hourly consumption data during that period.

Real-time pricing represents the most dynamic time-based form of pricing, as the kWh charge varies hourly (or as often as every five minutes in the New England wholesale market) based on actual market prices or utility estimates of hourly marginal generation or purchased power costs. Implementation of such pricing could enable customers to lower their electric bills through price-induced conservation or by shifting loads to lower price, off-peak periods.

The 2005 Act also requires each state commission to have commenced its investigation of interconnection no later than August 8, 2006, and to make a final determination no later than August 8, 2007. ”Interconnection” for purposes of this provision means the interconnection to the local distribution company of an electric customer with on-site generation in accordance with the interconnection standards developed by the Institute of Electrical and Electronics Engineers -- IEEE Standard 1547 for Interconnection Distributed Resources with Electric Power Systems. 16 U.S.C. § 2621(d)(15).

On April 24, 2006, the Commission issued an order of notice scheduling a prehearing conference in this proceeding for May 16, 2006, to be followed by a technical session. The prehearing conference and ensuing technical session took place as scheduled. Participating in addition to Commission Staff were: Granite State Electric Company d/b/a National Grid

(National Grid), Public Service Company of New Hampshire (PSNH), Unitil Energy Systems, Inc. (UES), the New Hampshire Electric Cooperative (NHEC), the Office of Consumer Advocate (OCA), the Office of Energy and Planning (OEP), Wal-Mart Stores East, L.P. (Wal-Mart), Hunt Technologies, Inc. (Hunt), Granite State Hydropower Association (GSHA), Pentti Aalto, and Roy Morrison.

On May 16, 2006, Staff filed a letter with the Commission summarizing the discussion at the technical session and noting that the participants had agreed that National Grid, UES and PSNH would jointly file with the Commission an initial draft document setting forth the companies' view of the scope of the investigation. PSNH filed the scoping document on behalf of the three utilities on June 6, 2006. The participants and Staff conducted a technical session on June 15, with Staff thereafter submitting an agreed-upon final version of the scoping document, which the Commission adopted by secretarial letter dated August 4, 2006. The scoping document included 19 issues or questions relating to the smart metering standard and eight questions relating to the interconnection standard.

On September 7, 2006, Staff filed a letter recommending that the investigation be conducted in two phases based on the deadlines in the 2005 Act. Staff recommended that, in the first phase, the Commission investigate the smart metering and interconnection standards, which require a Commission decision by August 8, 2007. Staff also submitted a proposed procedural schedule for the first phase that included deadlines for discovery, testimony and hearing. On September 14, 2006, the Commission issued a secretarial letter that established a procedural schedule which included a preliminary comment deadline of September 29, 2006, and a November 3, 2006 deadline for parties' reply comments. Pentti Aalto, Roy Morrison, National Grid, UES, PSNH, Wal-Mart, Hunt Technologies, Inc., OCA, and Staff filed comments with the Commission.

## II. SUMMARY OF COMMENTS

### A. Smart Metering

The following is a summary of the comments submitted by the parties and Staff in response to the questions in the Scoping Document relating to Smart Metering:

**1. Has the state or Commission taken any action that would constitute "prior state action" with respect to the standard?**

PSNH, UES and National Grid asserted that the Commission had taken prior state action within the meaning of 16 U.S.C. § 2622(e) relating to time-based metering and time-differentiated retail electric rates in Docket No. DE 03-113, an investigation into advanced customer metering and pricing structures. UES and National Grid presented an additional argument. UES asserted that the Commission's order requiring UES to report to the Commission regarding the feasibility of real-time pricing for UES' largest commercial and industrial customers in Docket No. DE 05-064 (concerning the company's solicitation process for Default Service energy supply) exempts the Commission from investigating smart metering. *See Unitil Energy Systems, Inc.*, 90 NH PUC 378 (2005). National Grid made the same argument respect to Order No. 24,577 (January 13, 2006) in Docket No. DE 05-126, which required National Grid also to report regarding the feasibility of real time pricing for National Grid's large C&I default service customers. Finally, PSNH asserted that the Legislature's enactment in 1978 of RSA 378:7-a, 7-b and 7-c, which requires electric utilities to file optional time-of-use and time-of-day rates, may constitute prior state action, relieving the Commission of any obligation to consider real time pricing pursuant to 16 U.S.C. § 2622(e).[3]

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[3] Chapter 25, NH Laws of 2007 (HB 361), effective May 11, 2007, repealed RSA 378:7-a and 7-b and reenacted Section 7-a, authorizing the Commission to establish requirements for net metering, fuel diversity, fossil fuel generation efficiency, advanced metering, time-based rates and interconnection with on-site generation facilities in a manner not inconsistent with EPACT 2005.

Staff disagreed with the utilities' positions, referencing *Public Service Company of New Hampshire*, 89 NH PUC 2 (2004), entered in Docket No. DE 03-013. According to Staff, this order involved Commission approval of a settlement agreement entered into by the distribution companies and Staff, providing for each utility to install advanced metering for large commercial and industrial customers and establishing uniform reporting requirements regarding customer participation in advanced metering and optional services. Staff contended that this resolution of Docket No. DE 03-013 did not address real time pricing[4] or any other time-based pricing program for large or small customers, nor did it determine whether such time-based pricing programs should be mandatory or voluntary. Staff also disagreed with UES' and National Grid's assertion that the Commission-mandated study into the costs of acquiring the capability to develop time-based default service rates for large customers constituted an investigation into time-based metering and communications applicable to all customer classes as required by the Energy Policy Act of 2005.[5] Finally, Staff disputed the notion that the provisions of RSA 378:7-a, 7-b and 7-c, adopted in 1978, qualify as prior state action because the relevant Energy Policy Act provision states that the legislature must have voted on the standard or a comparable standard within three years prior to the enactment of the federal legislation in 2005.

**2. Are there statutory requirements that prevent New Hampshire utilities from offering "real time" pricing?**

PSNH pointed out that RSA 369-B:3,IV(b)(1)(A) states that PSNH's price for default service shall be the company's "actual, prudent, and reasonable" cost of providing the power but did not assert that the statute prohibited real time pricing. Staff asserted that the relevant language in RSA 369-B:3,IV(b)(1)(A) does not mandate average-cost pricing, and further pointed out that New Hampshire's electric industry restructuring legislation, RSA 374-F, is silent

[4] See definition at page 3.
[5] 16 USC 2621 (d)(14)(A)

on the structure of default service prices for the post-transition service period. Therefore, Staff concluded that the Commission has the authority to implement time-based pricing for PSNH customers provided the associated revenues are reconciled to “actual, prudent, and reasonable” supply costs. Neither UES nor National Grid responded to this question.

**3. Qualitatively, what are the costs and benefits of time-based pricing for default service?**

PSNH stated that commercial and industrial customers prefer energy prices that are reasonably known and predictable. According to PSNH, time-based rate structures that result in greater price uncertainty impose additional costs on customers. PSNH did not, however, attempt to estimate the magnitude of these additional costs.

While Staff acknowledged that all customers value rate stability and predictability, Staff suggested that the likelihood of less stable rates be evaluated in light of potential benefits from time-based pricing. Staff suggested that time-based pricing can benefit New Hampshire customers in two fundamental ways. First, retail rates that reflect the costs of generating and/or purchasing electricity at wholesale would reduce the inter- and intra-class subsidies associated with default service rates that are not time-differentiated. Staff explained that inter- and intra-class subsidies are the economic terms used to describe the income transferred from customers who use a relatively low proportion of their energy on-peak to those who use a relatively high proportion on-peak. Staff noted that this benefit is not dependent on customers changing their consumption habits in response to the time-based prices.

Staff stated that the second way customers can benefit from time-based pricing is by responding to price signals. According to Staff, customers can, by such response, reduce the overall market price volatility in their load zone, promote more efficient resource use, and lower their energy bills. Thus, Staff concluded that the Commission should recognize the qualitative benefits to time-based pricing.

**4. What is the experience with real time pricing and what are the implications of this experience for implementing real time pricing in New Hampshire?**

Only PSNH and Staff addressed this question directly. PSNH contended that its Voluntary Interruptible Program (VIP), which involves the voluntary curtailment of load by large commercial and industrial customers, incorporates many of the characteristics of real time pricing. PSNH explained that the VIP program is open to all customers who have hourly metering. PSNH did not provide any data on the number of customers participating in the program or the magnitude of actual interruptions. PSNH reported that, for July 18, 2006, a summer day where electric use was at a peak and where PSNH called for voluntary interruptions, the estimated participation in the interruption ranged from 33 to 48 percent during the hourly intervals when VIP curtailments were in effect[6]. PSNH reiterated its contention that, for a price response program to be effective, it must be conducted on a voluntary basis with limited frequency in curtailments so as not to affect the operations of participating customers unreasonably.

According to Staff, many states have implemented both voluntary and mandatory real-time pricing for default service customers and the results demonstrate that competitive suppliers will respond by offering customers appropriate alternatives. Staff related that the New York Public Service Commission estimated that approximately 700 default service customers and 1,500 retail access customers will be subject to real-time pricing. In addition, Staff noted that the New Jersey Board of Public Utilities expanded the class of customers served under its hourly-

[6] On May 22 PSNH filed for certain changes to its VIP rate to increase participation and potentially capture greater benefits for all customers by possibly reducing the system's peak coincident with the ISO-NE peak and thus reduce PSNH's payments to ISO-NE for installed capacity (DE 07-067) under the Forward Capacity Market (FCM). On June 15, 2007 the Commission issued an Order Nisi approving requested VIP tariff changes (Order No. 24,762).

priced Basic Generation Service to all customers above 1 megawatt effective June 1, 2007.[7] The previous threshold was 1.25 megawatts. Staff recommended that the Commission consider the cost savings implications of a rate design involving real-time pricing in its deliberations regarding implementation of a smart metering standard.

**5. Which time-based rate structure is appropriate for each customer class for each utility?**

No utility responded to this question directly. Wal-Mart stated that real-time pricing models are superior to critical peak pricing and other time-based pricing methods because real-time pricing dynamically reflects the hourly changes in the cost of production and purchased power whereas other methods fix prices based on historical analyses of prices. Wal-Mart believes that all default service customers, regardless of size and sophistication, should be subject to real-time pricing.

Staff disagreed with Wal-Mart's recommendation to charge all default service customers on a real-time basis. Staff noted that small customers have little ability to respond to real-time pricing signals and currently have few competitive alternatives to Default Service. Staff expressed the view that mandatory implementation of real-time pricing for small customers could expose such customers to significant bill increases.

According to Staff, should the Commission consider it important to promote demand response among small customers, it should develop a fixed-price rate structure that reflects the fundamental cost differences in generation and/or purchasing electricity at the wholesale level. Staff noted that these fundamental cost differences occur when moving from summer to winter and from off-peak to peak on a daily basis. Staff also asserted that cost-based seasonal and time-

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[7] *In re Provision of Basic Generation Service,* 2005 WL 3359450 (N.J. Bd. of Public Utilities, Dec. 8, 2005). The Board based its decision on the conclusion that "accurate market pricing reduces the possibility for inter- and intra-class subsidies, encourages customers to consider conservation, renewable energy and distributed resource alternatives, promotes load management and generally gives customers more control over their energy costs."

of-day rate components would strengthen the link between wholesale and retail prices and promote competitive markets. For UES and National Grid, Staff asserted that such a rate structure could be attained without much effort by adding a time-of-day structure to the fixed monthly wholesale prices that each company currently seeks through its small customer power procurement solicitation.

Staff recommended a similar fixed-price rate structure for large customers, even though most large customers are able to respond to hourly price signals and have competitive alternatives. As with small customers, Staff asserted that the recommended rate structure for large customers of UES and National Grid could be attained by each company modifying its large customer power procurement solicitation. Regarding PSNH customers, Staff stated that pricing Default Service to small or large customers under a rate structure with seasonal and time-of-day features would represent a significant change from the current practice of charging customers based on a flat per-kWh rate. Finally, Staff cautioned that rate structures with time-of-day features could not become effective immediately if a utility's metering and billing systems had to be upgraded.

**6. Should implementation of time-based pricing be mandatory, voluntary or some combination of the two?**

PSNH stated that time-based rates should be offered only on an optional basis for smaller customers because those customers are less able than larger, more sophisticated customers to modify their consumption habits or absorb the higher cost of implementation. PSNH expressed opposition to mandatory implementation of time-based pricing for default service on the ground that the associated bill impacts could be avoided by customers purchasing their electric service requirements from competitive suppliers under rates more to their liking.

Wal-Mart stated that time-based pricing should be mandatory for all customer classes.

Although National Grid did not respond directly to this question, in a response to Staff Data Request 1-10, National Grid observed that the choice between voluntary or mandatory time-of-use pricing depends on the structure of the rate proposal, the goal of the offering, the customer class, and the net benefits of the offering. Like PSNH, National Grid expressed concern that customers who lacked the ability to respond to price signals would be at great risk under critical peak pricing and hourly pricing. National Grid suggested that these rate structures be offered only on a voluntary basis to avoid the risk of bill impact for those customers unable to respond to price signals.

National Grid also suggested that certain rate structures be offered on a mandatory basis because providing such rate options would give customers the chance to arbitrage between non-time differentiated default service and time-of-use Default Service. National Grid identified the acceptable structures as: (a) monthly/seasonal prices; (b) time-of-use pricing to large customers based on the time periods in effect prior to deregulation; (c) time-of-use pricing to a broader group of commercial and industrial customers based on cost/benefit analysis; and (d) time-of-use pricing that reflects more differentiation between cost periods.

UES, in discovery, stated that if time-based pricing is shown to provide net benefits, experience suggests that it should be implemented on a mandatory basis.

Staff opposed PSNH's recommendation to implement time-based pricing on a voluntary basis, but agreed with National Grid that the choice depends on the rate structure and goal of the offering, the customer class, and the net benefits. Staff asserted that because there are few competitive market opportunities for small customers, the primary rate design goal for this class should be the promotion of demand response during peak pricing periods. Staff contended that the best way to achieve this goal is through the reflection in default service rates of mandatory time-of-day and seasonal market price differentials.

Finally, Staff noted that the response of large customers to optional tariff services including remote access metering, pulse output service, and interval data services has been negligible at best. Based on this experience, Staff concluded that the goals of time-based pricing for large customers are unlikely to be met under a voluntary approach.

**7. What is the current availability of interval meters and communications equipment by customer class and is technology available to communicate price changes to customers?**

PSNH recommended against using metering equipment as a conduit for time-sensitive pricing information for retail customers. According to PSNH, a better approach is to use the meter to measure, store and transmit energy and demand information, and then perform the conversion to dollars and cents outside of the metering system. PSNH stated that customers can be alerted to price changes through links to websites, paging systems or automated voice message systems.

PSNH reported that all large commercial and industrial customers have been equipped with interval data recording meters. Such meters offer the advantage of on-board storage of large amounts of data, typically more then 60 days of 30-minute interval data. Of these approximately 1,500 meters, PSNH stated that only about 200 are connected to a phone line to enable the interval data to be accessed remotely. For meters not connected to a phone line, interval data must be gathered by “probing” the meter using a hand-held reading system.

UES stated that it has installed advanced meters for all of its largest customers. Advanced metering is defined as including: (a) an interval data meter with mass memory capability that is capable of recording and transmitting pulses; and (b) a modem to provide data to the customer, the customer's competitive supplier, or the distribution company. UES also stated that it offers advanced meters to smaller customers for a fee.

National Grid stated that interval meters have been installed for all of its General Service Time-of-Use (G1) customers. However, to access the interval data stored in these meters, National Grid stated that customers must either rent equipment that allows for periodic readings via phone lines or purchase pulse service from National Grid.

**8. Does each utility currently have the ability to bill customers based on "real-time" pricing?**

PSNH stated that its large power billing system is unable to bill on a real-time basis. PSNH could not estimate the costs to upgrade the system to process hourly price and load information.

In discovery, National Grid stated that its customer information system does not currently have hourly pricing capabilities and would require custom reprogramming to obtain those capabilities. National Grid also stated that it is in the process of converting that system to the system its affiliate uses in New York. According to National Grid, the one-time cost to obtain hourly pricing capability for New Hampshire customers is estimated to be in the $200,000 to $300,000 range.

UES also lacks the ability to bill customers on an hourly basis. UES estimated the cost to customize its current customer information and billing system for the three G1 customers that receive default service from UES to be $242,000, plus an annual administrative cost of $51,300, which would result in the first year's billing for large G1 customers to be $293,000, or $24,400 per eligible customer. Staff noted that UES did not address in its response the cost to hand calculate the bills of the three default service customers priced on an hourly basis.[8]

**9. What are the available technology options for communicating with interval meters and transmitting the price or cost information to utility and customer? What are the strengths and weaknesses of each? Which technologies make the most sense for each utility and each customer class?**

Aalto and Morrison responded to this question by proposing that a smart metering pilot program be implemented for residential and small commercial customers based on real-time pricing, electronic metering, two-way communications between meters and the utility's central office, and the ability to execute load control automatically based on preset price trigger levels. The real-time prices would be refreshed every five minutes rather than every hourly in order to allow the resulting demand response to qualify as dispatchable load as defined by the regional grid operator, ISO-New England. The pilot would have two phases. Phase I would involve 100 participants, run for one year, cost approximately $350,000, and be funded through the System Benefits Charge currently paid by all New Hampshire electric customers. The primary purpose of Phase I would be to assess the operation of a smart metering system with these features: (a) extraction of ISO-New England five-minute pricing information, (b) adjustment of five-minute prices to cover other costs, (c) transmission via satellite paging network price signals to control devices in homes or businesses of participating customers, (d) control of load using preset trigger prices, (e) monitoring power consumption and calculating customer power bills, (f) transmission via satellite of consumption and cost data to the utility, and (g) transmission of usage data to customers via e-mail and web site posting.

Aalto and Morrison also described a potential second phase of the pilot program, involving approximately 1,000 customers using real-time pricing and potentially other

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[8] See UES' November 1, 2006 filing in Docket No. DE 05-064 regarding the feasibility of instituting real-time pricing for its large commercial and industrial customers.

communication media for the transmission of control data. In the course of discussing the scoping document at technical sessions, PSNH, UES and National Grid offered to meet with Aalto and Morrison to determine whether a pilot project was workable given each utility's technical and operational capabilities.

**10. What issues should be considered when implementing real-time pricing?**

PSNH commented that the extent of any education or outreach program would depend on the complexity of the time-based pricing programs selected by the Commission, the potential impacts of the programs, and whether such programs are voluntary or mandatory.

Should the Commission pursue time-based pricing for all or some customers, Staff noted that a coordinated education and customer outreach program would be crucial to the success of such pricing. Staff identified the primary goals of any outreach effort as: developing and implementing a plan to advise eligible customers of the need to reduce peak electric demand including how to shift load from high- to low-cost periods, educating eligible customers about the pros and cons of time-based pricing, training account representatives to calculate the monetary benefits to customers of changing demands in response to price signals, and publicizing utility energy service tools that will assist customers in managing time-based pricing.

**B. Interconnection**

The following is a summary of the comments submitted by the parties and Staff in response to the questions in the scoping document relating to interconnection:

1. **Has the State or the Commission taken any action that would constitute "prior state action" within the meaning of the standard? Do the interconnection provisions in N.H. Code Admin. Rules Puc 900 qualify as a comparable standard?**

UES and PSNH stated that the Commission's current interconnection policy was originally articulated in a series of orders, including *Small Power Producers and Cogenerators*, 66 NH PUC 83 (1981) and *Small Energy Producers and Cogenerators,* 69 NH PUC 352 (1984). PSNH noted that the practices and policies have been updated over time to comply with the ISO-New England rules. PSNH, UES and National Grid observed that net metering projects are covered by state statute, RSA 362-A:9, and N.H. Code Admin Rules Puc 900, concerning net metering for customer-owned renewable energy generation resources of 25 kilowatt-hours or less. The two utilities contended that these procedures constituted existing policy, but did not characterize the procedures as prior state action. PSNH stated that the utilities had been designing, and monitoring interconnection agreements with independent power producers, generation facilities on customer premises and net-metering customers according to these standards for 20 years.

UES pointed out that the procedures in the Puc 900 rules were adopted prior to implementation of IEEE Standard 1547 and recommended that the Commission review the rules for compliance with the IEEE standard.

PSNH proposed that the only interconnection policies considered in the current investigation be related to (a) on-site generators, that is, any generator connected to the utility grid that is behind a customer's retail meter and used only for the customer's needs or which sells power subject to state regulation only, (b) qualifying facilities (QFs)[9] and certain non-QFs selling their output to the host utility; and (c) net metering. PSNH noted that such facilities generally interconnect with the distribution system at voltages of 34.5 kilovolts or less. PSNH pointed out that such facilities are not covered by the ISO-New England interconnection procedures unless the generators are five megawatts or greater.

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[9] The term "qualifying facility" refers to independent power producers that qualify, pursuant to federal rules, as cogenerators covered by PURPA. *See* 16 U.S.C. § 796(18)(b).

**2. Should New Hampshire adopt a standard interconnection policy for all utilities? Should the standard apply to all new on-site generators regardless of size?**

National Grid stated that its current interconnection application form for small renewable generators is consistent with the Puc 900 rules. For larger projects in New Hampshire, National Grid stated it would follow a process similar to the policies its affiliates use in Rhode Island and Massachusetts. National Grid suggested that the Commission adopt the interconnection policy approved by the Massachusetts Department of Telecommunications and Energy (DTE) in that agency's Docket No. D.T.E. 02-038. National Grid had participated in the docket and provided a copy of the resulting interconnection policy with its comments. UES also referred to the Massachusetts policy as preferred guidance for interconnection for larger generators in New Hampshire.

PSNH agreed that a standard interconnection policy should be in place for all utilities. According to PSNH, Commission has already adopted such a standard in the dockets leading to the 1981 and 1984 decisions cited above, as well as through the Puc 900 rules. PSNH suggested that interconnection standards apply to all generators regardless of size but noted that specific requirements should vary depending on a number of factors including the size of the generator, whether the generator is synchronous or induction, and the specific circuit to which the generator is connected. PSNH observed that, in its experience, generators greater than five megawatts require more study and more protection. PSNH noted that the ISO-New England requires such large generators both to be examined to assure that they will not have an adverse effect on the transmission system and also to supply more data on generator status in real-time than is required from small generators.

**3. Is the IEEE Standard 1547 for interconnecting distributed resources with Electric Power Systems currently observed by utilities in New Hampshire? What are the advantages and disadvantages of (a) adopting the IEEE 1547**

**standard; (b) adopting the National Association of Regulatory Utilities Commission (NARUC) Model Interconnection Procedures; and (c) applying the Federal Energy Regulatory Commission (FERC) rules (FERC Order No. 2006 (May 12, 2006)) to New Hampshire on-site generators?**

PSNH observed that while PSNH has not formally adopted IEEE Standard 1547, the current interconnection process addresses most aspects of the IEEE standard. In addition, PSNH noted that IEEE Standard 1547 provides only minimal requirements. Therefore, PSNH recommends that the details of implementation of the standard should be left to the individual utilities.

PSNH disagreed with an aspect of Standard 1547, which states in relevant part: "Any additional local requirements should not be implemented to the detriment of the functional technical requirements of this standard." PSNH expressed concern that this standard could override the need for generators to address interconnection requirements on a case-by-case basis. Consequently, PSNH recommended that IEE Standard 1547 be used only as a guide, and not a requirement, for generation interconnection.

UES noted that the FERC interconnection policies incorporate the IEEE interconnection specifications. USES stated that UES' interconnection policies were adopted before the release of IEEE Standard 1547 but asserted that there are no substantive differences between its policies and the IEEE Standard. UES added that regardless of which standard the Commission chose to implement, UES would recommend that engineering judgment override standards to provide a determination regarding whether a lesser requirement is appropriate for a specific situation.

Regarding the issue of interconnection generally, Staff recommended that, due to the technical nature of interconnection and the differences among the utilities' processes, the parties should meet in technical session to develop a recommendation for the Commission.

## III. COMMISSION ANALYSIS

### A. Smart Metering

#### 1. Prior State Action

We begin by addressing the contention that we need not consider the federal standard for smart metering because of "prior state action." The Commission's decision in *Public Service Company of New Hampshire,* 89 NH PUC 2 (2004) in Docket No. DE 03-013, less than three years prior to the enactment of the 2005 Energy Policy Act, arguably provides a basis for declining to consider the new federal smart metering standard. However, Section 2622(e) does not preclude our consideration of the new standard and, in our judgment, the public good is advanced if we consider smart metering and options for time-based rates.

#### 2. Costs and Benefits of Time-Based Pricing

We find that time-based pricing that enables demand response can be a cost-effective alternative to adding new generation, adding to transmission and/or distribution capacity, or increasing electricity usage, provided that consumers reduce or shift their usage in response to changes in retail prices. In such circumstances, consumers responding to price signals benefit by paying lower electricity bills. Other customers also benefit because even a modest demand reduction at times of high prices tends to mitigate spikes in locational marginal prices[10] and reduce overall price volatility. Reduced price volatility in turn benefits customers because it can lower the premiums demanded by suppliers of fixed-price products. In addition, reducing peak demands can benefit all customers by reducing generation by the most inefficient units and reducing Forward Capacity Market payments to ISO-NE for installed capacity requirements to assure system reliability..

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[10] The "locational marginal price" is the hourly spot price of electricity in the wholesale market administered by ISO New England, set zonally (as opposed to region-wide) to account for geographically specific limitations on the generation and transmission of electricity.

PSNH maintains that customers desire rate stability and that rate structures that result in greater price uncertainty impose additional costs on customers. While we agree that customers value rate stability, there is also value to customers in the ability to make decisions that can result in lower bills. For this reason, as discussed below, we will require utilities to modify existing default service rate designs in ways that balance the benefits of rate stability with the need for economic incentives to control peak demand. Such modifications can also have the effect of providing greater encouragement to customers to invest in energy efficient equipment to further lower their electricity bills.

**3. Time-Based Rate Structures**

We turn to the question of which time-based rate structure is most appropriate for each customer class. As noted above, while none of the electric utilities responded to this question directly, Wal-Mart recommended that all default service customers, regardless of size, be billed on the basis of real-time pricing.

We do not believe it would be consistent with the public interest to require real-time pricing immediately for all default service customers or all customers in any particular class. Since small customers currently have few competitive opportunities and little ability to respond to real-time price signals, mandating such a rate structure now could expose some of those customers to substantial increases in their electricity bills. While it is true that most large customers appear to be capable of responding to hourly price signals, and those that do not have that capability, or choose not to, can purchase hedge or fixed price products to protect against market price volatility, we conclude that it is appropriate to observe how large customers respond to time-of-day rates before considering mandatory real-time pricing. In addition, we note that each utility has language in its tariff that provides customers with appropriate metering equipment the option to purchase their energy requirements directly from ISO-NE on a real-time basis.[11] Nonetheless, our policy objective is to give all metered customers[12] the option, within a reasonable time frame, to purchase their energy requirements at real-time retail prices. Accordingly, we will direct Staff to discuss with interested parties how to implement this objective. Consideration should be given to the technical requirements and timetable to enable all types of metered customers to take power based on ISO-NE's real time locational marginal price for New Hampshire, with necessary ancillary services and capacity charges, at pricing intervals as frequent as every 5 minutes, and with a minimum of overhead or other added costs.

Instead of adopting any form of mandatory real-time pricing at this time, we will require the utilities to modify their tariffs to provide for fixed, time-based pricing of default service for all metered classes.

**a. National Grid and UES Small Customers**

Time-based default service rates for National Grid's small customers should be based on the current rate structure and rate-setting methodology, but with a time-of-day structure added.[13] That is, the rate for each time-of-day period should equal the average of the corresponding monthly market prices resulting from the small customer solicitation.[14] Once established, these time-of day rates would remain fixed for a period of six months until revised based on the results of a new power supply solicitation. Implementation issues associated with time-of-use rate structures will be addressed in technical conferences, discussed in greater detail below, involving Staff, the utilities and other interested parties.

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[11] Although the option applies to all customers regardless of size, we recognize that only the largest are likely to give it serious consideration because the savings would have to be sufficient to offset the associated metering and billing costs as well as the cost of NEPOOL membership.

[12] Street lighting is typically not metered.

[13] National Grid's small customer default service rate is currently based upon a simple average of six monthly wholesale prices contained in the winning bid from the most recent power supply solicitation. The rate is reset every six months based on the prices obtained from the new solicitation.

[14] Such rates will be appropriately adjusted for administrative and other retail-related costs.

Implementation of a time-of-day default service rate structure for UES' small customers will not be as straightforward as it will be for National Grid. There are two issues. The first is that UES small customer requirements are met through a portfolio of four power supply contracts, each with different start and end dates and different terms. As a result, customers will not face full time-of-day market price differentials until all of the existing supply contracts have been replaced. Instead, time-of-day price signals will need to be phased-in over time as expiring contracts are replaced. The phase-in start date will be considered in technical conferences. The second issue concerns the nature of the replacement contracts. As with National Grid, the default service rate that applies to UES small customers is based on a simple average of six monthly wholesale prices. Unlike National Grid, the monthly wholesale prices used to calculate this six-month average do not result from a single power solicitation. Rather, each monthly wholesale price is itself the average of the corresponding monthly prices in the four contracts that comprise the supply portfolio. Because each contract is entered into at a different time and for a different period, the four contract average wholesale price is, in effect, a hybrid of prices of different vintages and terms. This tends to dilute the impact of changes in wholesale market prices on retail rates.[15] Thus, continuing with the portfolio approach will mean that time-of-day market price signals will continue to be mitigated, which will diminish or distort the demand response of small customers to the price changes. For this reason, we will address in a future default service proceeding for UES whether the portfolio approach to procuring default service supplies for small customers should be continued. Specifically, we intend to examine whether the rate stability objective which underlies the portfolio approach to default service procurement

[15] Indeed, UES' stated goal in using the portfolio approach to procuring default service supplies for small customers is to offer those customers some protection against volatile wholesale prices.

can coexist with our policy goal of encouraging customers to vary their electricity consumption in response to changes in wholesale power prices.

**b. National Grid and UES Large Customers**

We will consider how to implement time-based rates for large customers of UES and National Grid based on the results of power solicitations that seek time-of-use-based wholesale pricing.[16] However, large customers would continue to face default service rates that vary monthly based on the results of quarterly solicitations. By adjusting retail rates for large customers every three months, default service prices would continue to track changes in market prices.

**c. PSNH Small and Large Customers**

We will also consider how to implement the same rate structures discussed above for PSNH default service customers. However, because PSNH does not procure its default energy service power requirements through competitive solicitations, the individual time-of-use rates for small and large customers would be based on actual time-differentiated costs incurred by PSNH in providing default service to these customer groups. That is, the time-of-day rates for small customers, for example, would be based on six monthly forecasts of average power costs for those time periods appropriately adjusted for any over- or under-collection of costs during the prior rate period.

To be consistent with our decision to re-evaluate UES' portfolio approach to default service supply procurement, we will examine in a future default energy service proceeding whether PSNH's procurement of supplemental power under long term fixed-priced contracts conflicts with the goal of promoting price-based demand response and, if so, whether that

[16] Traditional time-of-use rates include fixed kWh charges that typically vary by season and by time-of-day.

practice should be discontinued and replaced with purchases in the real time market and/or under short-term contracts.

**d. Time-of-Day Rate Structures**

Staff noted in its reply comments that ISO-New England has recommended that the conventional peak/off-peak time-of-use rate structure be modified to provide customers a reasonable opportunity to shift load from peak period. Specifically, ISO-New England recommended a structure that includes a minimum of three periods: peak, shoulder and off-peak. The peak period would be shorter than the peak period in conventional time-of-use rates, which for some utilities extends from 7:00 a.m. until 8:00 p.m., Monday through Friday.[17] Reducing the number of hours in the peak period and adding a shoulder period would, according to ISO-New England, provide customers a much greater incentive for customers to shift load out of the peak period because the shorter peak period produces a higher cost-based peak rate, while the shoulder period provides a convenient home for the load shifted out of the peak period.[18] We find these arguments persuasive as a policy matter and will consider how to implement three-period, time-based rate structures for both small and large default service customers. Further, we will require that the time-of-day periods be based on an analysis of hourly market price variations in ISO-New England's day-ahead and real-time markets.

**e. Critical Peak Pricing**

We also agree with the principle that customers able and willing to respond to unpredictable price spikes during critical peak periods should be encouraged to do so. One way to provide this encouragement is to offer customers lower time-of-use rates for non-critical

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[17] The remaining hours on weekdays and all hours on weekends are typically designated as off-peak hours.
[18] While this incentive could be created by simply shortening the peak period and lengthening the off-peak period, pricing usage during the "shoulder" hours at a new off-peak rate would provide customers an incentive to increase usage during those hours without any economic distinction from true off-peak hours when wholesale electricity costs are lowest.

periods (compared to standard time-of-use rates) in return for agreeing to face higher prices during critical peak periods.  The amount of the credit that customers receive during the non-critical periods should be based on the costs that the utility avoids when the participating customer either reduces or shifts load in response to the critical peak price or pays the full price. Because critical peak pricing will help New Hampshire's utilities reduce their energy and capacity costs and help the region address its system reliability concerns, we will require each utility to submit draft tariff language that incorporates a critical peak pricing option for all metered customer classes.  We will then consider such draft language along with metering, timing and other practical considerations that are to be discussed by the parties and Staff in technical conferences before seeking to phase-in voluntary critical peak pricing options with time of use rates.  At a minimum, the draft tariff language should: (a) define the conditions that justify declaring a critical peak, (b) identify the time periods that critical peak prices can be charged, (c) address whether there should be a limit on the number of critical peak declarations, and (d) specify the notification period.  Finally, we note that the optional nature of these tariff provisions should address the concerns of those who believe that the large price differentials inherent in critical peak pricing would create undue hardship for some customers.  That said, we do not rule out the possibility that critical peak pricing could be made mandatory in the future for some customer classes.

**4. Voluntary or Mandatory Time-based Rates**

If customers are given a the choice to take default service under either a non-time differentiated rate or a time-based rate, it is logical to expect that those who stand to benefit from the time-based rate will select that option while those who do not stand to benefit will select the non-time differentiated option.  Such choices could lead to a higher peak demand and higher overall default service costs than would otherwise occur. Since this is contrary to the goals of controlling peak demand and reducing costs to customers, absent a showing that certain customers will face unacceptable and unavoidable rate impacts, we find a mandatory approach to time-based rates to be superior to a voluntary approach.

**5. Time-Based Pricing Implementation Issues**

The utilities have asserted that existing metering and billing systems limit their ability to introduce time-based rate design changes. In relation to billing, for example, they assert that they currently do not have the capability to bill customers on a real time basis and that obtaining that capability will take time and money. No utility, however, addressed in its comments whether it has the capability to bill customers under time-of-day rate structures. Accordingly, we direct Staff to meet with the utilities to ascertain current metering and billing capabilities and, if necessary, gather information on the time and cost to upgrade these systems in ways that are consistent with the rate design policies described in this Order.

In addition, to avoid or limit the replacement of defective or old meters with metering equipment that would limit pricing options, we find that metering standards for both small and large customers should be put into place to provide appropriate guidance to the utilities regarding their purchasing decisions. Consequently, we direct Staff to investigate meter replacement strategies with a view to establishing appropriate standards.

Staff will also investigate with the parties the appropriate timeframe for converting small customers to time-based rates. Staff will also consider with the parties whether time-of-use pricing should apply to customers above some threshold annual usage based on the assumption that small residential customers are unlikely to be able to shift enough load to reduce their bills.

Staff is further directed to work with the utilities to develop plans to educate customers as to the pending change in rate design and on ways to control their peak demands. These plans should include, but not be limited to, information on the potential bill impacts of time-based rates and the opportunities for customers to participate in utility and ISO-New England-sponsored energy efficiency and demand response programs. Consideration should also be given to possible changes in the design of utility-funded energy efficiency programs to enable efficient customer responses to time-of-use rates as well as real-time and critical peak pricing options. PSNH should also consider how its Voluntary Interruptible Program (VIP) tariff might be replaced, modified or supplemented by real-time and critical peak pricing options.

Given that the utilities would incur costs to implement the rate designs approved here, alternative cost recovery approaches should also be examined. Regarding the issues of real-time and critical peak pricing options, we direct Staff to work with the utilities and other interested parties to develop these rate options. Finally, we direct Staff and the parties to file, no later than September 28, 2007, a detailed report on their discussions.

**6. Smart Metering Pilot Program**

Given our decision not to mandate real-time pricing for any group of customers at this time and the direction given to Staff to review metering, billing and other technical considerations to implement mandatory time-of-use rates as well as voluntary options for critical peak and real-time pricing, we do not currently see a need to develop and implement a pilot program whose primary purpose is to assess the operation of a metering and communications system designed to support real-time pricing.

**B. Interconnection**

As noted by the utilities, New Hampshire has had interconnection standards in place for 20 years, and those standards have been modified as necessary over the years to comport with the requirements of the regional grid operator. Nevertheless, we will consider the current interconnection standards, as expressed in the Puc 900 rules, relative to IEEE Standard 1547. Because of the technical nature of IEEE Standard 1547, we direct Staff to meet with the parties in a technical session to discuss whether it is appropriate for the Commission to adopt the federal interconnection standard pursuant to 16 U.S.C. § 2621(d)(14). We welcome information regarding interconnection policies from other states to determine if we should adopt similar standards. We also ask the parties and Staff to make a recommendation as to whether there should be a uniform interconnection policy for all new on-site generators regardless of size, and to report to the Commission regarding the relative merits and disadvantages of adopting (a) the IEEE 1547 standard, (b) the National Association of Regulatory Utilities Commission (NARUC) model interconnection procedures, and (c) the Federal Energy Regulatory Commission (FERC) rules for New Hampshire on-site generators. The parties and Staff shall file their recommendations with the Commission no later than August 27, 2007.

**Based upon the foregoing, it is hereby**

**ORDERED** that PSNH, National Grid and UES shall file draft tariffs to provide for fixed, time-based pricing of default service for all customer classes as detailed in this Order no later than September 28, 2007; and it is

**FURTHER ORDERED**, that PSNH file no later than November 30, 2007 a detailed description of the cost-based methodology that it intends to use to calculate the small and large customer time-of-use default service rates.

**FURTHER ORDERED**, that Staff and the parties file a report with the Commission no later than November 30, 2007 that details the current metering and billing capabilities of the utilities; the time and cost to upgrade those systems in ways that are consistent with this Order; a program to educate customers as to the pending change in rate design and on ways to control their peak demands; how to implement real-time and critical peak pricing options for default service; how to implement three-period, time-based rate structures for both small and large default service customers; recommendations regarding the possible phase-in of time-based rates for small customers; and the appropriateness of establishing a usage threshold below which small customers would be exempt from time-based pricing; and it is

**FURTHER ORDERED** the parties and Staff shall meet in technical session to consider whether it is appropriate for the Commission to adopt the EPAct Interconnection Standard; whether the Commission should adopt a uniform interconnection policy; and the relative merits and disadvantages of adopting the IEEE standard, the NARUC standard, and the FERC standard for interconnection, and shall file a report regarding the engineering standards no later than August 27, 2007.

By order of the Public Utilities Commission of New Hampshire this twenty-second day of June, 2007.

| Thomas B. Getz<br>Chairman | Graham J. Morrison<br>Commissioner | Clifton C. Below<br>Commissioner |
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Attested by:

Debra A. Howland
Executive Director & Secretary