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November 3, 2006

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 South Fruit Street Suite 10
Concord, New Hampshire 03301

Re: DE 06-061
Investigation pursuant to the Energy Policy Act of 2005
Staff's Reply Comments

Dear Ms. Howland:

On May 16, 2006, the New Hampshire Public Utilities Commission (Commission) issued an Order of Notice opening Docket No. DE 06-061 to investigation five new federal standards that were added to Title I of the Public Utility Regulatory Policies Act by the Energy Policy Act of 2005 (EPAct). Those standards are: time based metering and communication; interconnection; net metering; fuel sources; and efficiency of electric generation. The EPAct requires state regulatory commissions to investigate whether it is appropriate to implement any of the new five standards. With respect to time based metering and interconnection, state regulatory agencies must complete their investigation within two years of EPAct's enactment which is August 5, 2007.

On July 25, 2006, Staff filed a document which delineates the proposed scope of the investigation, and the Commission approved the document on August 4, 2006. Staff and the participants in the docket agreed that the first phase of the investigation would focus on time based metering and interconnection because those investigations must be completed by August 5, 2007.

On September 14, 2006, the Commission issued a secretarial letter which approved a procedural schedule that required all participants in the docket to file reply comments on November 3, 2006. The purpose of this letter is to file Staff's comments with the Commission. As noted above, these comments are restricted to time based metering and interconnection.

A copy of this letter and Staff's comments have been sent to the participants in this docket by electronic mail and a hard copy will be mailed to them via first class post.

Please let me know if you have any questions.

Sincerely,

Suzanne G. Amidon
Staff Attorney

Service List

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Energy Policy Act 2005 **DE 06-061**

REPLY COMMENTS

OF

THE COMMISSION STAFF

Introduction

The Staff of the New Hampshire Public Utilities Commission ("Staff") submits these reply comments in response to the Commission's letter order of September 14, 2006 which provided for the filing of comments and reply comments on the requirements of the Energy Policy Act of 2005 ("EPAct"). Sections 1251, 1252 and 1254 of EPAct require state commissions to consider five new federal standards that have been added to Title I of the Public Utility Regulatory Policies Act. These standards address net metering, dependence on fuel sources, fossil fuel generation efficiency, time-based metering and communications, and interconnection. The purpose of these reply comments is to provide guidance to the Commission on whether to adopt the proposed standard on time-based metering and communications and comments on the interconnection standard investigation.

Section 1252 of EPAct

EPAct requires each state regulatory authority to conduct an investigation and issue a decision whether or not it is appropriate to adopt a new time-based metering and communication standard.[1] The standard that the states are to consider is as follows:

> (14) TIME-BASED METERING AND COMMUNICATIONS.—(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall 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.

Several types of time-based rate structures are identified in EPAct. These include: (i) traditional time-of-use (TOU) pricing; (ii) critical peak pricing (CPP); (iii) real-time pricing (RTP), and (iv) credits for customers with large loads who enter into pre-established peak load reduction agreements with utilities.

1. Traditional TOU Pricing

Traditional TOU rates include fixed kWh charges that typically vary by season and time-of-day and reflect the utility's cost of generating and/or purchasing electricity at the wholesale level. Because these charges are established and communicated in advance of consumption, consumers can manage their electricity costs by varying their usage in response to such charges (for example, by shifting usage to a lower cost periods or reducing consumption in high cost periods.)

Seasonal TOU prices can be implemented using the traditional electromagnetic meter, which most small customers rely on. Time-of-day pricing, however, requires an electronic meter.

[1] Energy Policy Act of 2005, Section 1252(b).

2. Critical Peak Pricing

Critical peak pricing (CPP) is essentially TOU pricing with a dynamic component added that more closely tracks costs during extreme peak conditions. CPP is used to raise charges significantly to alert electricity customers during "critical peak" periods, such as the summer air-conditioning season. CPP can provide benefits in terms of reduced peak power usage, which may reduce transmission congestion and the burden on the distribution system during peak periods.

Under CPP, TOU prices are in effect except for certain peak days when prices will reflect the high costs of purchasing electricity at wholesale. Typically, users receive an alert shortly before the critical period starts in order to allow them to control their consumption and manage price risk. In return for requiring customers to pay the higher critical peak prices, the prices for non-critical periods are lowered.

To implement CPP, participating customers must install smart meters. Because these meters have high implementation costs, CPP efforts are likely to be focused on large customers.

3. Real Time Pricing

Real time pricing (RTP) represents the most dynamic time-based form of pricing, as the kWh charge varies hourly (or more often) based on actual market prices (quoted in advance) or utility estimates of hourly marginal generation or purchased power costs.

It is important to note that under EPAct prior state actions relating to time-based metering and communications are grandfathered provided: (i) the prior state action by the state commission was conducted in a proceeding considering implementation of the standard or comparable standard within the previous three years before enactment[2]; or (ii) a state legislature voted on the implementation of the standard or comparable standard also within the previous three years before enactment.

In order to assist the Commission in its review of the standard, participants in the subject docket developed a document that delineates the scope of the investigation for each of the five standards. The scoping document, which was filed with the Commission on July 25, 2006, contains nineteen questions relating to time-based metering and communications. Consistent with the procedural schedule approved by the Commission September 14, 2006, comments on these questions were filed by Public Service Company of New Hampshire (PSNH), Unitil Energy Systems, Inc. (UES), and Granite State Electric Company d/b/a National Grid (National Grid), New Hampshire's three regulated electric utilities; Wal-Mart Stores; and Hunt Technologies on September 29, 2006. In addition, Mr. Roy Morrison and Mr. Penti Aalto submitted a proposed pilot program design for RTP. In these reply comments, which are organized according to the questions set forth in the scoping document, Staff summarizes the parties' comments and provides its own analysis of the issues raised.

Questions and Responses

1. Has the state or the Commission already taken any action that may constitute "prior state action" under the Standard?

PSNH, UES and National Grid assert that the N. H. Legislature or the Commission has taken action in the past with respect to time-based metering and time-differentiated retail electric rates. All three utilities claim that the Commission is exempt from the

[2] The EPAct was enacted on August 5, 2005

requirement to implement the standard because the investigation in the Advanced Metering Docket (Docket No. DE 03-013) qualifies as "prior state action." UES also claims that the Commission's investigation in Docket DE 05-064 (Default Service) exempts the Commission from the requirement to implement the standard.3 Further, PSNH believes that that the enactment in 1978 of NH RSA 378-7-a. 7-b, and 7-c, which require electric utilities to file optional time-of-use rates and time-of-day rates, may constitute "prior state action."

In contrast, Wal-Mart contends that the Commission has not taken any action in regard to the standard.

Staff disagrees that the investigation and order in Docket No. DE 03-013 qualifies as "prior state action." While the Commission stated in an order of notice that the purpose of Docket No. DE 03-013 was to "investigate the feasibility, benefits and costs of the installation of advanced customer metering equipment by electric distribution companies, including the effect on demand response due to the use of advanced metering technology" and later directed the utilities to: address the benefits and detriments of mandatory RTP; determine whether to apply mandatory RTP to specific C&I customers; and provide a description of alternative rate design options; the final order (Order No. 24,263) addressed none of these issues. Instead, the Commission simply approved a Settlement Agreement between the parties and Staff that provided for each utility to install advanced metering for large C&I customers and the establishment of uniform reporting requirements with respect to customer participation in advanced metering and optional services. Not discussed in the order are the benefits and detriments of RTP or any other time-based pricing program for small or large customers; whether RTP or any

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3 UES' claims are contained responses to discovery. See Response to Staff 1-1.

other time-based pricing program should be mandatory or voluntary; the benefits and detriments of alternative rate designs; or time-of-use metering for residential consumers. Staff also disagrees with National Grid's statement that it committed in Docket No. DE 05-126 to conduct an investigation of whether to offer hourly-pricing to large G-1 Default Service customers. National Grid actually committed to investigate the "costs of acquiring the capability to price Default Service for large G-1 customers," which is a significantly narrower investigation. Thus, we question National Grid's assertion that the Commission has already taken steps to investigate standards that are comparable to the time-based metering and communications standard. Furthermore, National Grid's commitment relates to large customers only whereas the time-based metering and communications standard applies to each customer class.[4] Hence, National Grid's investigation is not comparable to the investigation mandated by Section 1252 of EPAct. Regarding PSNH's assertion that enactment of NH RSA 378-7-a. 7-b, and 7-c qualifies as "prior state action," Staff notes that the relevant EPAct provision states that the legislature must have voted on the standard or comparable standard within three years prior to the enactment of EPAct. Since the above referenced statutory provisions were enacted in 1978, PSNH's assertion is incorrect. In addition, the optional time-of-use tariffs to which PSNH refers relate to delivery service rather than default service, which is the primary subject of the standard.

[4] See PURPA §111(d)(14)(A).

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

Only PSNH and Wal-Mart addressed this question directly. PSNH expressed the view that Commercial and Industrial (C&I) customers prefer energy prices that are reasonably known and predictable in order to assist them in establishing budgets, business plans and production schedules. Thus, 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.

Staff accepts that all customers value rate stability and predictability. We believe, however, that the costs of less stable and predictable rates[5] must be evaluated in light of the real and unmistakable benefits of time-based pricing.

Staff believes 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 will reduce the inter- and intra-class subsidies associated with non-time differentiated default service rates.[6] 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. This benefit is not dependent on customers changing their consumption habits in response to the time-based prices. Consequently, Staff disagrees with PSNH's assertion that the benefits of time-based pricing are exclusively related to the ability and willingness of customers to respond to retail price signals.

[5] As well as the associated higher metering and billing costs.

[6] The magnitude of this reduction will depend on the extent to which retail rates reflect costs. Retail rates that are aligned with seasonal and peak and off-peak cost differences will be less successful in reducing cost subsidies than, say, RTP.

The second way that New Hampshire customers can benefit is by responding to the time-based price signals. Customers that engage in price-induced demand response can help themselves and others in the following ways: they can reduce overall price volatility in their load zone; they can promote more efficient resource use; and they can lower their own energy bills.[7]

Reducing electricity demand by even a modest amount at times of high wholesale electricity prices can mitigate spikes in locational marginal prices (LMPs) and reduce overall price volatility. Such effects will benefit all customers because they lower the premiums demanded by suppliers of fixed-price products.

Reducing electricity demand at times of high wholesale electricity prices also contributes to a more efficient use of resources. That is, the generation resources which are the most inefficient and use the highest cost fuels will be used less often if customers reduce demand in response to high wholesale electricity prices.[8] In addition, reducing customer demands during the peak hours benefits all customers through the deferral of new capacity.

Last but not least, by reducing usage during peak periods, customers that engage in price-responsive behavior realize significant bill reductions.

Unfortunately, the default service rates paid by the vast majority of New Hampshire's customers do not reflect the daily and hourly changes in wholesale prices. At most they

[7] Price-induced demand response can also provide some protection against market power abuse. Prices in ISO-NE's day-ahead and real-time electricity markets are set by the marginal bidder. If a bidder believes that the ISO requires its generation to maintain reliability, there is no limit to the price that it could charge. By reducing demand in response to time-based prices, the ISO is less likely to be in a situation where system reliability is dependent on generation owned by a single bidder.

[8] This leads to a reduction in the overall cost of electricity as well as lower environmental emissions. The converse is also true. Customers who consume during times of peak demand contribute to driving up the wholesale price for everyone.

change monthly and in most cases only seasonally. This can lead customers to behave in exactly the wrong way; that is, they increase consumption in the peak hours.[9] Such behavior leads to the dispatch of higher cost generating units and an increase in the need for generating capacity to serve the peak hour, the net effect of which is to increase the overall costs of electricity.

3. Which costs are the responsibility of customers and which are the responsibility of competitive suppliers?

All of the costs incurred in providing customers with a default service should be collected from default service customers only through retail rates. Power supply costs, associated losses, and the administrative costs associated with the design and implementation of the service should be recovered through kWh based rates. The latter category includes power supply procurement, supply-related working capital and supply-related bad debt. The fixed metering and billing costs associated with the service should be collected through the customer charge component of delivery rates.

4. What is the experience with "real time" pricing as a means to encourage demand response and promote retail access? What are the implications of this experience for implementing "real time" pricing in New Hampshire?

Only PSNH addressed this question directly. PSNH contends that its Voluntary Interruptible Program (VIP), which involves the voluntary curtailment of load by large C&I customers, incorporates many of the characteristics of RTP. The program is open to

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[9] This is explained by the fact that average cost pricing tells customers that a kWh consumed during the peak hours costs the same as one consumed in the middle of the night.

customers who have hourly metering available to estimate the amount of load curtailment when interruptions occur. Load curtailment estimates are based on hourly meter readings adjusted to account for normal load shapes and temperature differences. The program is typically operated annually during the high energy cost months of June through September each year. Unfortunately, PSNH provided no information on the number of customers participating in the program or the magnitude of actual interruptions. It did report, however, that the estimated participation rate for the July 18, 2006 interruption ranged from 33% to 48% during the hourly intervals when VIP curtailments were in effect.

Based on customer feedback, PSNH contends that an effective price response program should be conducted on a voluntary basis, limited in frequency so that curtailments produce the maximum benefit and designed so that interruptions do not unreasonably affect the operations of participating customers.

Outside of New Hampshire, Staff notes that many jurisdictions have already implemented mandatory RTP for default service customers and the results demonstrate that competitive suppliers will respond by offering customers appropriate alternatives. For example, the New Jersey BPU expanded the class of customers served under hourly-priced Basic Generation Service to all customers above 1 megawatt (MW) effective June 1, 2007.[10] The previous threshold was 1.25 MW. The NJBPU has also been exploring alternative rate designs for smaller C&I customers which would reflect hourly variations in energy costs without the uncertainties and volatility of hourly pricing. Proposals

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[10] NJBPU, Docket No. EO05040317, Decision and Order, December 8, 2005, pages 15-16. This action was taken in recognition of the Board's belief 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." Id. at 15.

include dividing the traditional on-peak period into shoulder and peak periods and pricing consumption in those periods accordingly.[11]

In addition, the New York Public Service Commission (NYPSC) has directed all jurisdictional utilities to implement hourly pricing for large customers, claiming that "the effort to pursue hourly pricing via the voluntary route has failed to achieve satisfactory results, with too few customers signing up for the voluntary program."[12] The NYPSC estimated that approximately 700 default service customers and 1,500 retail access customers will be subject to RTP. If every retail access customer taking service from a competitive supplier chooses an hourly pricing offer from among a variety of offerings, the NYPSC estimated that 2,200 of New York's largest non-residential customers, representing approximately 5,300 MW of aggregate load - roughly 15 percent of the total peak demand for electricity - would see and be billed at true day-ahead hourly market prices for electricity. The 5,300 MW of aggregate load subject to hourly pricing programs could yield total demand reductions during peak hours of approximately 750 MW, according to the NYPSC.[13]

In Texas, the Public Utility Commission designated a certificated retail electric provider to provide a safety net service for each customer class in each electric utility service area in the event that a competitive supplier leaves the market.[14] Safety net service for large customers is priced on an hourly basis.

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[11] Id, at 10.
[12] NYPSC, Order Denying Petitions for Rehearing and Clarification in Part and Adopting Mandatory Hourly Pricing Requirements, April 24, 2006, CASE 03-E-0641.
[13] Id, at 3.
[14] Texas electric utilities are required to separate their business activities into three units: a wholesale electric power generation company, a T&D company and an affiliated retail electric provider (AREP). Customers who failed to obtain generation service from a non-affiliated REP when competitive services became available were transferred to the AREP. Customers who obtained generation service from a REP

5. Can the demand response benefits of "real-time" pricing be achieved without the installation of energy management control systems?

Only PSNH and Wal-Mart addressed this question directly. Wal-Mart believes that the demand response benefits will be minimal without energy management control systems (EMCS), especially for customers with very large loads or multiple facilities. PSNH stated that it has no information on the use by its customers of EMCS to manage electricity demand in response to RTP.

6. What are the operational benefits (e.g., fewer estimated readings, meter reading labor cost savings, load data for engineering analysis, more efficient outage management, remote connect and disconnect functionality, and improved customer service) and challenges associated with smart meters?

Only PSNH and Wal-Mart addressed this question directly. PSNH distinguishes between smart meters and automated meter reading (AMR) technology without identifying the differences. In summary, PSNH states that a "fully functional, system wide, AMR deployment" could realize all of the benefits referenced in the question. Nonetheless, PSNH cautions that any decision to invest in AMR would need to balance the benefits with the cost of purchasing, testing and maintaining the equipment and associated software systems, the cost of upgrading data collection systems, and the cost of storm restoration and collections, operational tasks currently performed by personnel that may become expendable under AMR.

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but were subsequently dropped for any reason were provided safety net service by a certificated REP chosen by the Public Utility Commission.

Wal-Mart effectively expresses the same view as PSNH but with the AMR technology replaced with smart meters.

7. Which time-based rate structure is appropriate for each customer class in each utility?

None of the utilities responded to this question directly. PSNH's comments were limited to a description of the time-differentiation built into existing delivery rates.

Wal-Mart in its comments stated that RTP models are superior to CPP and other time-of-use methods because RTP dynamically reflects the hourly changes in the cost of production and purchased power whereas other methods fix prices based on historical analysis of prices. Wal-Mart believes that all default service customers, regardless of size and sophistication, should be charged on the basis of RTP.

Staff opposes Wal-Mart's recommendation to charge all default service customers on a RTP basis. This recommendation takes no account of the fact that small customers ordinarily have little ability to respond to RTP signals and currently have few competitive alternatives to default service.[15] For these reasons, mandatory implementation of RTP could expose small customers to significant bill increases.

If the Commission's primary goal for small customers is to promote demand response, a more realistic approach, in Staff opinion, is to develop a fixed-price rate structure that reflects the fundamental cost differences in generating and/or purchasing electricity at the wholesale level. These fundamental cost differences generally appear when moving from

[15] In particular, these customers would not be able to purchase fixed-price products that hedge the risks of fluctuating market prices

summer to winter and from off-peak to peak on a daily basis.[16] Cost-based time-of-day and seasonal rate components also strengthen the link between wholesale and retail prices and, hence, are consistent with the promotion of competitive markets. The above described time-of-use rate could be adjusted periodically (perhaps on a six month basis) to allow the default service price to more closely track changes in supply costs. For PSNH, this would represent a significant change from the current practice of charging all customers a flat per kWh rate that is adjusted annually. For UES and National Grid, the change would not be as significant since both companies currently invoice small default service customers based on a summer/winter rate structure. To implement the new rate structure, UES and National Grid would need to alter their small customer power supply solicitations to require wholesale pricing that features peak and off-peak prices that vary monthly. Retail rates that reflect the average of the peak and off-peak wholesale prices over a six month period could become effective as soon as each company's metering and billing systems are able to handle time-of-day pricing.[17]

Staff proposes a similar approach for large customers, even though most large customers are able to respond to time-based price signals and can purchase hedge products that protect against the price volatility associated with RTP.[18] For UES and National Grid, we believe consideration should be given to adding a time-of-day structure to the monthly wholesale prices and to pass those monthly prices directly to customers through retail rates. Such a rate design change would better align prices with the costs of supplying

[16] In regard to the time-of-day component, it is important to note that ISO-NE believes the peak period must be shorter than the traditional 16 hours in order to provide customers meaningful incentives to shift load. According to ISO-NE, this can be accomplished with a time-of-day rate structure that includes a minimum of three periods: peak, shoulder and off-peak.

[17] This assumes of course that implementation of the new rate structure is cost effective.

[18] Again, this assumes that implementation is cost effective.

electricity in Independent System Operator-New England (ISO-NE) energy market. In order to achieve uniformity in pricing across the state, PSNH would need to establish a similar default service rate design for its largest customers.

With these changes, default service rates for all large customers in New Hampshire would reflect time-of-day as well as monthly variations in power costs. Even if such a rate structure failed to achieve the Commission's goals for large customers, whether greater demand response or enhanced competition or both, the Commission would not be prevented from opening a generic proceeding to investigate the cost and benefits of moving to hourly pricing.[19]

8. Does the standard raise factual issues that should be considered on a utility-by-utility basis? For example, does RSA 369-B:3, IV(b)(1)(A) prohibit "real time" pricing for any PSNH customer class? In addition, does the statutory requirement that UES and National Grid procure their power requirements in the market prohibit time-based pricing for any customer class?

Neither UES nor National Grid responded to this question. While PSNH did respond, it failed to state its position on whether RSA 369-B:3, IV(b)(1)(A) prohibits "real time" pricing.

Staff believes that time-based pricing (including RTP) can be implemented by all three utilities without revising New Hampshire's restructuring legislation. Although RSA 369-B:3, IV(b)(1)(A) does provide that the price of default service shall be "PSNH's actual,

[19] UES notes in its November 1, 2006 report titled "Investigation of Hourly Pricing", Docket DE 05-064, that nine of its twelve Large G1 customers are currently receiving supplies from third-party competitive suppliers. Accordingly, it believes that the cost to develop and implement an automated system capable of billing on an hourly basis for the three remaining customers would be prohibitive.

prudent, and reasonable costs of providing such power," Staff does not interpret this language to mandate average cost pricing. On the contrary, we believe the restructuring legislation is silent on the structure of default service prices for the post-transition service period. For this reason, we believe 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.

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

Only PSNH and Wal-Mart addressed this question directly. PSNH stated that time-based rates should be offered only on an optional basis for smaller customers because those customers are least likely to be able to significantly alter their consumption habits or absorb the higher cost of implementation. Larger customers, according to PSNH, are more sophisticated in their use of energy and are more likely to be able to absorb the higher costs of implementation. Nonetheless, PSNH is opposed to mandatory implementation of time-based pricing for default service on the ground that the associated bill impacts can be avoided by the customer purchasing its energy requirements from a competitive supplier under a rate structure more to its liking.

Wal-Mart believes that to maximize the benefits, time-based pricing should be mandatory for all customer classes.

National Grid, in response to discovery, stated that the choice of 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.[20]

National Grid believes that mandatory offerings of the following rate structures create great risk to customers if they are not able to swiftly modify usage to avoid price spikes:

1. ISO-NE demand response credits;
2. critical peak pricing; and
3. hourly pricing.

Because of this price risk, National Grid stated that such structures should be offered on an optional basis. National Grid noted, however, that this risk could be avoided if customers purchase hedge products from competitive suppliers. This suggests that the mandatory approach is consistent with the policy goal of promoting competitive markets, at least for customers that have competitive options. If the policy goal is demand response, National Grid suggested that an optional approach would allow the utility to focus its marketing efforts on customers who are most able to manage their load response to price changes. Finally, National Grid argues that a mandatory approach would "remove the promise to customers that the utility price would be the comparable, benchmark against which customers would determine their savings from choosing an alternative supplier."

National Grid believes the rate structures identified below should be offered on a mandatory basis because creating these rates as options would give customers the chance to arbitrage between non-time differentiated energy service, time-of-use energy service and supplier offerings. The rate structures are:

[20] See National Grid response to Staff 1-10.

1. monthly/seasonal prices that reflect winning bids;
2. time-of-use pricing to G-1 customers based on the time periods in effect prior to deregulation;
3. time-of-use pricing to a broader group of C&I customers based on cost/benefit analysis; and
4. time-of-use pricing that reflects more differentiation between cost periods.

National Grid also argues that the opportunity to arbitrage would create unnecessary complexity in the procurement of energy services and the possibility of greater risks to suppliers of default service.

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

Staff is opposed to PSNH's recommendation for voluntary implementation of time-based pricing. As argued by National Grid, the choice of voluntary or mandatory implementation depends on the rate structure offering, the goal of the offering, the customer class and the net benefits of the offering. Since there are few competitive market opportunities for small customers, the primary goal for this class should be the promotion of demand response during peak periods. We believe this can be achieved best through the reflection in default service rates of mandatory time-of-day and seasonal market price differentials. We also disagree with PSNH's assertion that customers adversely impacted by time-based pricing can avoid the bill impacts by taking service from a competitive supplier under a rate structure more to its liking. The competitive supplier of a customer that elects competitive service will be assigned not only that customer's load but also the obligation to buy power in the market to match the customer's load pattern. In effect, the competitive supplier becomes responsible for the market costs of serving the customer's load along with all of the associated risks. If the competitive supplier is prudent in its operations, and we have no reason to believe it will not, we predict that it will seek to hedge the risk by purchasing appropriate risk management products. What is not in doubt is that the costs of supplying the customer's load will be collected through the price negotiated between the supplier and the customer. In short, there are no free lunches.

Staff also takes issue with National Grid's claim that the Commission or the Legislature promised customers that the utility price [structure] would somehow be comparable to the price structures available from alternative suppliers. Neither the restructuring legislation nor the Commission's orders contain any such promise.

Staff also notes that PSNH's position on time-based pricing and National Grid's position on hourly pricing are at odds with the actions of affiliated companies in other jurisdictions. PSNH 's affiliate, Connecticut Light & Power, sought approval on October 3, 2005 from the Connecticut Department of Public Utility Control to implement mandatory peak, shoulder and off-peak time-of-use rates for customers with maximum demand of not less than 350 kilowatts.[21] National Grid of New York has for some time been engaged in mandatory RTP for customers sized at 2,000 kW or above and recently agreed to extend this form of pricing to customers with maximum demands as low as 500 kW.[22]

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[21] See PSNH response to Staff 1-5.

[22] NYPSC, Order Denying Petitions for Rehearing and Clarification in Part and Adopting Mandatory Hourly Pricing Requirements, April 24, 2006, CASE 03-E-0641, page 7.

Finally, Staff notes that the response of customers to optional tariff services including remote access metering, pulse output service[23] and interval data services has been negligible at best. Both UES and National Grid report that none of their large customers have purchased remote access metering since the service became available in 2004, and only one customer has purchased pulse output service. Based on this experience, the goals of time-based pricing are unlikely to be met under a voluntary approach.

10. What are the available technology options for measuring energy and demand on an interval basis? What are the strengths and weaknesses of each? Which technologies make the most sense for each utility and each customer class?

Only PSNH addressed this question directly. Staff has nothing to add to PSNH comments.

11. 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?

PSNH does not recommend using metering equipment as a conduit for time sensitive pricing information for retail customers. A more reliable approach, according to PSNH, 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.

[23] Pulse output service allows the customers to access real-time meter data through a pulse interface device.

Customers can be alerted to the changing price of electricity through links to web sites, paging systems or automated voice message systems.

Staff agrees with PSNH that real times price are unlikely to be communicated to customers through metering equipment. Large customers using energy management control systems to automatically shed load may, however, require links between meters and the technology that controls electrical consuming equipment. This is because some EMCS may be programmed to reduce load on certain pieces of equipment if total load of the facility exceeds a pre-specified level.

12. What is the current availability of interval meters and communications equipment and systems by customer class? What is the timeline for acquiring such capability if not currently available?

UES states that it has installed advanced meters for all of its G1 customers. Advanced metering is defined as (i) an interval data meter with mass memory capability; (2) includes a modem capable of providing data to the customer, the customer's competitive supplier, or the distribution company; and (3) is capable of recording and transmitting pulses. The cost of the interval data meter and the modem is recovered from customers through the distribution rates for the class.

UES also offers advanced meters through its Enhanced Metering Service to non-G1 customers, for whom the cost is not included in distribution rates. UES also offers a pulse service, for a fee, to both G1 and non-G1 customers. Pulse service allows the customer to access real time interval data.

PSNH has interval data recording meters installed on all Rate LG and Rate GV accounts (approximately 1500 meters). Interval data recording meters offer the advantage of on-board storage of a large amount of data (usually more than 2 months of 30 minute interval data). Only about 200 of these meters are connected to a phone line, enabling remote access to the interval data. Most of the phone-read meters are connected to "land lines." Some are connected to cell phones. For meters that are not connected to the phone-line, the interval data must be gathered by "probing" the meter using a hand-held reading system.

Interval meters have also been installed for all of National Grid's General Service Time-of-Use (G1) customers. To access the interval data, however, customers must either rent equipment from the Company that allows for periodic readings via phone lines or purchase pulse service from the Company.

13. Does each utility currently have the capability to bill customers based on "real-time" pricing? If not, what is the timeline for acquiring such capability and what changes need to be made?

Only PSNH responded to this question directly. The response indicated that PSNH's Large Power Billing System as currently designed and coded is unable to bill on a real-time basis. Moreover, without a complete set of detailed requirements and specifications, PSNH stated that it is nearly impossible to accurately estimate the time and cost to change its system to process hourly price and load information. PSNH added that it may also be necessary to "create larger databases capable of containing the volume and attributes associated with the hourly interval data."

In response to discovery, National Grid stated that its Customer Information System (CIS) does not currently have hourly pricing capabilities and would require custom programming to obtain those capabilities.[24] National Grid also stated that it is in the process of converting its CIS to the Customer Services System (CSS) used in New York, which was recently modified to provide hourly pricing capability for New York customers. That conversion is projected to be complete by late 2007. The incremental cost to obtain hourly pricing capability for New Hampshire customers is estimated to be in the $200,000 to $300,000 range.[25]

Like National Grid, UES currently does not have the capability to bill customers on the basis of an hourly tariff. However, UES agreed in Docket DE 05-064 to investigate the costs of acquiring that capability for Large G1 customers and to report the results of its investigation to the Commission by November 1, 2006. An initial review of that report indicates that nine out of the twelve Large G1 customers are currently receiving power from third-party competitive suppliers. Accordingly, UES believes the cost to customize its current retail customer information and billing system for just three customers would be prohibitive. UES estimates the cost to be a one-time $242,000 plus annual administrative cost of $51,300, which equates to $24,400 per eligible customer. Not addressed in the report is the cost to hand calculate the bills of the three customers subject to hourly pricing, which would appear on its face to be more cost effective solution to the problem.

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[24] See response to Staff 1-9.

[25] The details underlying this estimate are included in the report filed November 1, 2006 in Docket DE 05-126 regarding the costs of acquiring hourly pricing capability for large customers in New Hampshire.

14. What are the monetary costs and benefits of time-based pricing?

Only PSNH responded to this question directly. PSNH stated that potential monetary benefits include energy and capacity cost savings due to load reduction and shifting in high cost periods, but went on to say that it is unable to quantify those benefits without knowledge of how customers shift or reduce load in response to time-based pricing. With regard to monetary costs, PSNH believes that its billing and metering systems will require extensive amounts of time, expense and capital to function properly for certain time-differentiated energy pricing options.

Given the complete lack of hard data on the costs and benefits of time-based rates structures in the comments, Staff recommends opening a proceeding to fill that information gap. In order to focus this effort, Staff proposes that the cost/benefit analyses be conducted based on the small and large customer pricing structures suggested in the comments to Question 7. Since interval data meters that can accommodate time-based pricing have already been installed for large business customers, we anticipate that the cost side of the cost/benefit analysis for large customers will be dominated by the costs to upgrade automated billing systems and improving communications capability.[26] Staff expects that some of this information will be contained in the reports that UES and National Grid filed November 1, 2006 on hourly pricing.

[26] Although lost revenues associated with demand response programs are not an incremental cost and, hence, have no place in a cost/benefit analysis, they do discourage utilities from promoting demand response absent a collection mechanism. As such, the scope of the proceeding should provide for the discussion of this issue.

15. What implementation issues should be considered? For example, should utilities develop education and outreach plans, develop targeted technical assistance programs, and/or implement pilot programs? What would these efforts entail?

PSNH contends that the extent of any education or outreach program will likely depend on the complexity of the time-based pricing programs selected, their potential rate impacts, and whether the programs are voluntary or mandatory.

If the Commission intends to adopt a policy of time-based pricing for some customers, Staff believes that a coordinated education and customer outreach package is crucial to the policy's success. The primary goals of this effort would be to: (i) create and implement a plan to advise eligible customers of the need to reduce peak electrical demand including how to shift load from high to low cost periods; (ii) educate eligible customers about the pros and cons of time-based pricing including how the actual cost of electricity varies by time of day and by season; (iii) train account representatives how to calculate benefits that could accumulate over time if proper responses to hourly price signals were made; and (iv) publicize utility energy service tools to ease a customer's transition to time-based pricing. Staff agrees with PSNH that a program for RTP would be more extensive than one geared to fixed time-of-use rates.

16. How should existing default service wholesale supply contracts be treated if time-based or "real-time" default service is implemented and starts before the end of the existing contract(s)?

Only PSNH and Wal-Mart responded to this question directly. PSNH stated that its supplemental power purchases are typically of short duration, up to one year.

Accordingly, it does not believe the existing supply contracts will pose a barrier to implementing time-based (including "real time") pricing for default service. Wal-Mart added that existing default service wholesale contracts should be restructured to provide for RTP.

Staff agrees with PSNH but adds that the existence of fixed-price contracts, whether of short or long duration, should not preclude PSNH from implementing RTP expeditiously.[27] Staff's reasoning is provided in its response to Issue 18. As regards National Grid, we note that its longest fixed price contract has a term of only six months. Consequently, we do not anticipate existing contracts being a factor in the implementation of time-based pricing for G1 or Non-G1 National Grid customers. The same argument applies to UES' G1 customers. Finally, as regards UES' Non-G1 customers, Staff believes that the existence of long-term contracts in the Non-G1 portfolio does not preclude the Commission from implementing time-based pricing. Any difference between the revenues from time-based pricing and actual supply costs can be collected from or returned to customers subject to the time-based prices. The amount of the reconciliation would diminish over time as UES restructured its portfolio to better match the time-based rate structure approved by the Commission.

17. What "real-time" pricing information is available and how will it be communicated to customers? What adjustments do utilities expect to make to these "real time" prices?

[27] PSNH's inability to bill customers on an hourly basis would, however, delay the implementation of RTP. See Staff's comments on Question 13.

Only PSNH and Wal-Mart responded to this question directly. Staff agrees with PSNH that because of the precise definition of RTP included in EPAct, utilities offering RTP are likely to utilize the hourly prices in ISO-NE's day-ahead energy market. Staff is not familiar with the hour-ahead prices referenced by Wal-Mart in its comments.

Regarding adjustments to hourly prices, we recommend that the Commission continue the practice adopted in DE 05-064 of recovering through default service rates the administrative costs associated with default service design and implementation. In addition, default service rates should reflect losses and the costs associated with supply-related working capital and supply-related bad debt.

18. How will "real-time" prices be reconciled with actual supply prices? How should these cost differences be collected from customers? Can the utilities provide billing information on an hourly basis that reflects both real-time price and eventual settlement price?

Only PSNH and Wal-Mart responded to this question directly. In summary, PSNH stated that implementation of RTP could create significant over- or under-collection of energy costs if the prices in utility bi-lateral contracts do not track the hourly prices. PSNH suggests that the resulting cost differences be rolled into the default service rate in a subsequent period (e.g. monthly, quarterly, or annually).

Wal-Mart is opposed to reconciling "real time" prices and actual supply costs. Wal-Mart stated that a customer's final bill should be based on the prices communicated to it prior to consumption. Reconciling or adjusting the "real time" prices after the fact would substantially diminish the value of RTP, according to Wal-Mart.

If the Commission directs UES or National Grid to provide default service to its large general service customers on a RTP basis, Staff expects that the utility will enter into a contract with a third-party supplier for requirements service priced based on ISO-NE's day-ahead energy market for the New Hampshire zone.[28] The day-ahead energy market produces financially binding schedules for the production and consumption of electricity one day before the operating day. That is, generation and demand bids that clear in the day-ahead market settle at prices determined in that market. The real-time market reconciles any differences between the amount of energy scheduled day-ahead and real-time load.[29]

Because prices in the day-ahead market will be different from the corresponding prices in the real-time market,[30] the requirements contract will likely require the buyer to pay all costs associated with such price differences unless, of course, the seller agrees to accept the price risk.[31] If the price risk is to be shouldered by the buyer, Staff believes the difference should be collected from or paid to default service customers subject to RTP. To do otherwise would mean that other customers would have to pay a portion of the costs of providing a RTP service, which would be contrary to the principle of cost causation.

Staff believes the question of reconciling "real time" costs and revenues for PSNH is more complex, particularly if the Company continues to be obligated to provide default

[28] Because Staff does not currently believe that RTP for small customers is realistic, the issue of reconciling revenues from RTP with the costs of existing UES long-term supply contracts for Non-G1 customers is not addressed.

[29] While the day-ahead market produces the schedule and financial terms of energy production and use for the operating day, a number of factors can change that schedule, including unforeseen generator or transmission outages, transmission constraints or changes from the expected demand.

[30] Significantly different in some cases.
[31] If so, a price premium is likely to be embedded in the contract prices.

service from its own generation assets, supplemented as necessary with market purchases. Under such a scenario, one option would be to price default service to large customers based on estimates of PSNH's day-ahead hourly marginal supply costs. Such estimates may or may not be close to the corresponding hourly prices in ISO-NE's day-ahead energy market depending on whether PSNH's marginal resource is a purchase in the spot market or a bi-lateral contract that is priced to reflect forward prices for the term of the contract. Another and perhaps better option is to base the hourly prices on the ISO-NE day-ahead market. In either case, the revenues from these hourly prices are unlikely to match PSNH's actual supply costs. In this circumstance, the revenue shortfall or excess would be collected from or returned to customers subject to hourly RTP and not shared with other customers. Furthermore, we believe this reconciliation should be accomplished in a way that does the least damage to the hourly price signals.

19. How will this information be used? What control equipment is available on the customer end? If pricing information is provided, what technology exists to take this information and use it to control load based on pricing inputs?

Only Wal-Mart and PSNH responded to this question directly. Wal-Mart stated that price-based automatic load control could substantially increase the cost of implementing time-based pricing and make payback much longer than necessary. Customers should be allowed to make the decision on how to participate in RTP, according to Wal-Mart. PSNH stated that only large customers are likely to be able to generate sufficient savings to justify the cost and inconvenience associated with price-based load control equipment.

Staff believes that energy management control system technology has evolved significantly over the past few decades such that large customers have real choices when it comes to automated management of electrical loads in response to time-based pricing. We agree with Wal-Mart, however, that any decision to use this technology in combination with time-based default service prices should be the sole responsibility of the customer.

Conclusion

Staff respectfully requests that the Commission carefully consider these reply comments before taking any action on the time-based metering and communication standard.

Section 1254 of EPAct

The standard for consideration under Section 1243 of EPAct concerns Interconnection. Under this standard, interconnection service means interconnection to the local distribution company of an electric customer who has on-site generation in accordance with the interconnection standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems.

Interconnection

Comments concerning Section 1254 of EPAct were received from National Grid, UES and PSNH. National Grid made a recommendation on interconnection though it didn't respond directly to the 8 issues listed in the scoping document under Section 1254.

National Grid states that the "interconnection policy approved by the Massachusetts Department of Telecommunications and Energy in Docket D.T.E. 02-38 … is a good approach to addressing future interconnections in New Hampshire that would not fall under the existing rules." For support, National Grid states that UES, Northeast Utilities and National Grid all participated in the development of, and use of, the new Massachusetts interconnection policy. The new interconnection standard for Massachusetts was provided as an attachment to National Grid's comments. National Grid also provided the interconnection standards used in Rhode Island and the Small Generator Interconnection Policy proposed by ISO-NE.

UES provide detailed and useful comments on New Hampshire's interconnection history and its own practices though it did not specifically address the eight questions of the scoping document. Generally, UES supports the National Grid recommendation to use the MA DTE policy for generators that would not fall under the Commission's existing rules.

PSNH answered the 8 questions as well as provided several documents outlining detail its interconnection policy. PSNH states that a standard interconnection policy should apply for all utilities in New Hampshire (Question 4) and that the Commission has already adopted such a standard, at least with respect to Qualified Facilities (QFs) and net metering customers. PSNH believes that standards should apply to all generators regardless of size (Question 5) though PSNH recognizes that numerous factors, such as size of generator or type of circuit, will affect which specific requirement applies to the generator. PSNH also stated that IEEE 1547 should, if adopted, be used only as a guide for generation interconnection (Question 7).

Conclusion

Staff believes that due to the technical nature of interconnection and the differences between what National Grid and UES support and PSNH's position on interconnection, a feasible and effective interconnection policy can best be reached by convening a technical session/workshop. Staff expects an interconnection recommendation for the Commission's consideration would be filed soon thereafter.

Respectfully submitted

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November 3, 2006