THE STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Docket No. DE 06-061

DIRECT TESTIMONY OF

Stephen R. Hall
Michael B. Coit
and
Daniel S. Comer

Investigation Into Implementation
of the Energy Policy Act of 2005

September 17, 2007

I. INTRODUCTION

Q. Please state your names, business addresses and positions.

A. My name is Stephen R. Hall. My business address is PSNH Energy Park, 780 North Commercial Street, Manchester, New Hampshire. I am Rate and Regulatory Services Manager for Public Service Company of New Hampshire ("PSNH").

A. My name is Michael B. Coit. My business address is 1250 Hooksett Road, Hooksett, New Hampshire. I am a Senior Engineer for PSNH.

A. My name is Daniel S. Comer. My business address is 73 West Brook Street, Manchester, New Hampshire. I am the Director of Customer Services for PSNH.

Q. Mr. Hall, have you previously testified before the Commission?

A. Yes, I have testified on numerous occasions before the Commission over the past twenty-seven years.

Q. Mr. Coit, have you previously testified before the Commission?

A. No, I have not.

Q. Would you provide a brief summary of your educational background and work experience?

A. I received a Bachelor of Science degree in electrical engineering from the University of New Hampshire in 1984. I am currently employed as a Senior Engineer in the Meter Engineering department at PSNH where I have worked since 2003. I have worked in the electric utility metering industry since 1987, including nine years as an Application Engineer for General Electric's Meter Division where I also served as an instructor for numerous metering schools and training sessions around the world.

Q. Mr. Comer, have you previously testified before the Commission?

A. No, I have not.

Q. Would you provide a brief summary of your educational background and work experience?

A. I have a Bachelor's Degree in Business Administration from the University of New Hampshire. I have been employed at PSNH for over 25 years, serving in various capacities during that time. My customer service experience with PSNH includes periods of time as a Credit Supervisor, Training Supervisor, Credit and Collections Manager, Customer Service Manager and I have been the Director of Customer Service for the last 3½ years.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the Commission's Order No. 24,785 issued August 31, 2007 granting PSNH's Motion for Rehearing. PSNH had concerns about the apparent requirement in the Commission's earlier order in this docket (Order No. 24,763 dated June 22, 2007) to implement time-differentiated prices for energy service for all customers. PSNH is pleased that the Commission has provided it with the opportunity to elaborate on those concerns.

In this testimony, we will describe PSNH's current metering and billing systems and capabilities. We will provide information on the amount of time and expense that would be required to implement mandatory time-differentiated pricing for energy service, and we will describe issues surrounding real time pricing. Finally, we will recommend a course of action for implementation of the standards set forth in Section 111(d)(14) of the Public Utility Regulatory Policies Act as amended by the Energy Policy Act of 2005.

II. METERING CAPABILITIES

Q. Mr. Coit, please provide definitions for the terms that you will use in describing PSNH's metering capabilities.

A. The following definitions will apply for the purpose of this testimony:

Load Profile (LP) Meters: Meters that are programmed to record energy consumption (and/or other metered quantities) in short time intervals. The recorded information is commonly referred to as "interval data" or "load profile data". For PSNH, those intervals are 30 minutes in duration. The interval boundaries coincide with hourly (and half hour) time points on "clock time".

Time Of Use (TOU) Metering: TOU metering is a method of determining time-differentiated consumption quantities. Typically, TOU metering results in "on-peak" and "off-peak" kWh and kW demand values. Those TOU values may be calculated and displayed by a meter programmed specifically for a defined TOU rate schedule, or they may be derived from LP meter interval data using customized programs to process the data.

Advanced Metering Infrastructure (AMI): AMI is a term that is loosely applied to a variety of metering systems. The common element is that the metering system supports two-way communication between the utility and the meter, and it enables the collection of interval data in at least 60-minute intervals. Most systems offer many other features, but those features vary by system supplier and the underlying technology employed by the AMI system. It is important to note that in order to make effective use of the high volume of data generated by an AMI system, a Meter Data Management (MDM) system must be developed. The MDM system is not always included as part of the AMI system sold by the AMI system supplier. The MDM system impacts many business systems and can easily double the cost of the underlying metering hardware and data collection software.

Real Time Pricing: A billing system that allows for energy and demand prices to vary on an hourly basis. It is designed to reflect market pricing which varies with the price of fuel. The pricing model used with real time pricing in the electric utility industry in New England is assumed to change on an hourly basis. In addition, it is assumed that billing calculations will be derived at the end of each monthly billing cycle from the interval data gathered from the installed meter.

Smart Meters: A loosely defined category of metering that is used as part of an AMI system. A smart meter has two-way communication capabilities and can provide load profile interval data (minimum interval duration of 60 minutes).

Q. Please describe the metering currently utilized for PSNH's larger customers.

A. All customers taking service under Primary General Delivery Service Rate GV and Large General Delivery Service Rate LG have LP meters. The meters are equipped with internal modems and pulse initiator option boards. Approximately 50 of the 1500 installed recording meters for Rate GV and LG customers are actually connected to a phone line, which is used to extract interval data from the meter.

The specific programming of these meters varies depending on the service type and billing determinants that are required. Most are programmed for recording delivered kWh and kQh[1] quantities. Those metered quantities are displayed by the meter as total cumulative values, and are also stored separately as interval data. The next most common configuration is to record and display delivered kWh, received kWh, lagging kvarh[2], and leading kvarh. Other customized configurations exist, but are uncommon.

---

[1] A mathematical calculation used to determine kva-hours.

[2] Kilovolt-ampere reactive hours (the units used to measure quadergy).

Q. Can the existing metering equipment be used to bill large customers under time-differentiated pricing?

A. Yes, it can. Since our existing meters record interval data, the data could be collected on a monthly basis and used to bill time-differentiated prices. However, the billing system would have to be programmed to process interval data in this manner. The amount of effort necessary to perform such billing system modification is discussed in the next section of this testimony. However, the metering is already configured to provide the input data that would allow such processing to occur on a monthly billing cycle.

It is important to note that existing metering is <u>not</u> configured to display time-differentiated metering quantities. It would require a change to the existing metering to enable local time-differentiated display functionality. The existing meters would need to be either recycled in an "upgrade and reprogram" process, or replaced with new meters configured to display time-differentiated quantities.

If we replaced the approximately 1500 recording meters with similar meters capable of displaying time-differentiated billing quantities locally, it would cost approximately $800,000 (including installation costs) and would take two to four years to complete using PSNH's existing work force. The cost of upgrading meters which could be upgraded, and replacing the ones that could not, would be roughly $450,000 (including installation costs) and would take two to four years to complete.

Using the metering equipment to separate usage information into on-peak and off-peak periods limits flexibility with respect to time-differentiated rate design because any changes to time periods would require reprogramming every meter.

It is much more practical to continue to utilize existing meters to gather interval data, and then perform any time-differentiated billing analysis of the interval data through the billing system. This approach enables maximum flexibility to accommodate time-differentiated rates and/or Daylight Saving Time shift changes that may be required, and it allows PSNH to continue to utilize the existing meters.

Q. Can existing meters be used to communicate pricing signals to customers?

A. No. Existing meters are not capable of serving as a conduit for price signal communications. While existing meters are designed to transmit consumption data reliably, meters are not well suited for communicating pricing information. They are designed to accurately measure and record energy consumption and related metering quantities. They have rudimentary communication capabilities designed to communicate metered quantities to utility personnel and, in a limited fashion, to customers. To our knowledge, there is no communication option available for large customer metering that could be used to transmit both metering data and time-sensitive pricing information reliably enough to avoid billing issues.

Meters are often placed in locations where they are subject to harsh environmental and electrical conditions. Extreme temperatures, high humidity, and voltage spikes from lightning strikes all contribute to reliability problems with remote, meter-based communication equipment. It would be more logical to make use of other systems, such as internet based communications, to transmit and/or receive critical time-sensitive pricing information. Those systems are better protected physically and are more reliable systems for communicating pricing information.

Q. Please describe the metering currently utilized for PSNH's smaller customers.

A. The most common type of residential and small general service meter used by PSNH remains the basic induction-type electromechanical (E/M) self contained single phase meter with a mechanical kWh register.

For those small general service customers who require demand metering, many meters are electronic solid state (SS) type meters, though some E/M meters with mechanical demand registers are still in service. The table below shows the approximate numbers of these meters in service as of September, 2007:

Meter Type	Single Phase	Network	3-Phase	Total
Electromechanical kWh	486,000	22,000		508,000
Electronic AMR (RF) kWh	9,800	30		9,830
Demand Metering (SS & E/M)	17,000	2,700	18,600	38,300
Totals:	512,800	24,730	18,600	556,130

PSNH's single phase electronic meters are typically not upgradeable to accommodate time-differentiated pricing. Rather, the meters are specifically designed for (and limited to) kWh and kW demand metering. Upgrading the 3-phase meters, while possible in some cases, would be logistically difficult and expensive.

Q. Can the existing metering equipment be used to bill time-differentiated pricing for smaller customers?

A. Not for the vast majority of our smaller customers. There are currently 52 residential and 36 general service rate meters that are being used for the optional TOU delivery rates. Those meters could be used to provide information necessary to bill time-differentiated energy service prices. However, approximately 556,000 meters would need to be replaced in order to implement time-differentiated pricing if such pricing were made mandatory.

Q. What would it cost to upgrade the metering for smaller customers to enable time-differentiated pricing?

A. To respond to this question, it is necessary to identify the type of TOU metering to be installed before cost estimates can be developed. Here are some of the most common approaches used in the industry:

<u>Conventional TOU metering</u>

Conventional TOU metering involves installing a meter that has been programmed to accumulate kWh and possibly calculate kW demand based on a pre-defined time period that is not subject to frequent changes. The defined schedule of “on-peak” and “off-peak” periods may vary based on a limited number of defined “seasons”, but once programmed the TOU schedule is essentially static. The meters used for this type of TOU metering calculate and display TOU metering quantities locally. Meter readers typically read the metering data visually and manually enter readings on a handheld computer.

If PSNH were to implement this type of TOU metering on a mandatory basis for all residential and small general service customers, the estimated cost of the meters alone (excludes installation costs) is shown in the table below:

Meter Type	Single Phase	Network	3-Phase	Total
TOU kWh	$38,880,000	$1,980,000		$40,860,000
AMR (RF) TOU kWh	882,000	$3,300		885,300
TOU kWh & Demand	1,700,000	324,000	$2,790,000	4,814,000
Totals:	$41,462,000	$2,307,300	$2,790,000	$46,559,300

The cost associated with purchasing, programming, and installing the meters is estimated to be between $11 million and $15 million. There would also be on-going costs related to time-keeping battery maintenance at an annual cost of approximately $100,000 per year. In addition to the above costs, it would also take longer to read each meter and enter the data, increasing the number of meter readers and reading equipment required to complete each meter reading route.

We estimate that it would take two to five years using PSNH's existing work force to change out the meters identified above.

TOU Metering based on LP Data Processing

If TOU billing determinants were calculated by processing interval data recorded by each meter, the estimated cost of the meters alone (excludes installation costs) is shown in the table below:

Meter Type	**Single Phase**	**Network**	**3-Phase**	**Total**
TOU kWh	$106,920,000	$5,060,000		$111,980,000
AMR (RF) TOU kWh	2,156,000	6,900		2,162,900
TOU kWh & Dmd.	3,740,000	621,000	$6,045,000	10,406,000
Totals:	$112,816,000	$5,687,900	$6,045,000	$124,548,900

The installation costs would be essentially the same as described above for conventional TOU metering.

Meter reading costs would increase significantly due to the extra time it takes to download the interval data, and the increased number of meter readers and equipment it would take to gather the data. Data processing costs would also increase significantly due to the enormous volume of data that would need to be processed.

We estimate that it would take two to five years to change out the meters identified above.

AMI system

As discussed in PSNH's Motion for Rehearing, an AMI system would cost on the order of $150 million to $200 million and likely take five to seven years to implement. It is uncertain whether a comprehensive AMI system would even be technically feasible given the rural nature and rugged topography of many parts of New Hampshire. Much more study would be required to pursue this option.

III. BILLING SYSTEM DESCRIPTION AND CAPABILITIES

Q, Mr. Comer, please describe the customer billing systems currently used by PSNH.

A. PSNH currently uses two separate billing systems. The Customer Information System (CIS) is utilized to bill approximately 475,000 residential and small commercial customers. The Large Power Billing (LPB) system is used to bill approximately 2,000 large commercial and industrial customers, as well as our street lighting customers.

Q. What are the current capabilities of PSNH's LPB system with respect to billing large customers under time-differentiated prices?

A. PSNH currently bills 119 of its largest customers (Rate LG) under time-differentiated pricing for delivery service only. However, the system is currently incapable of billing the energy service rate on a time-differentiated basis.

Q. Please describe the LPB system modifications, costs and time frame involved if time-differentiated pricing for energy service were mandatory for all large customers.

A. If all large customers were billed under time-differentiated prices for energy service, especially one that included shoulder periods or that used different time periods than currently used for delivery service[3], PSNH's LPB system would require significant programming modifications and testing to support such new requirements. The LPB system modifications would include core billing functions for rates maintenance, bill calculation, bill printing, revenue reporting and multiple interface systems. Additionally, significant modifications to the supplier billing process, including EDI data exchange, would be required. Without knowing the specific business requirements and details of the time-of-use pricing program, it's virtually impossible to develop an accurate time and cost estimate, but based on prior IT projects of this magnitude, a rough estimate would be at least two years of development and a cost of at least $2 million.

Q. What are the current capabilities of PSNH's CIS system with respect to billing smaller customers under time-differentiated prices?

A. PSNH's current CIS system is capable of billing residential and small general service customers using peak and off-peak time-differentiated rates for

[3] On-peak:7:00 a.m. to 8:00 p.m. on non-holiday weekdays. Off-peak: all other hours.

delivery service. PSNH currently has 52 residential customers under its optional Residential Time-Of-Day Delivery Service Rate R-OTOD delivery rate, and 36 small commercial customers under its optional General Time-Of-Day Delivery Service Rate G-OTOD. These rates provide on-peak and off-peak periods for distribution and transmission prices, but there are no shoulder periods. Energy service is not currently billed with any on-peak/off-peak price differences, but the system is capable of doing so with certain limitations.

Q. Please elaborate on the limitations of the existing CIS system with respect to time-differentiated pricing for energy.

A. The CIS system has the ability to bill on-peak and off-peak periods only (i.e., it cannot bill shoulder periods). Moreover, while the CIS system has the capability to bill energy service at on-peak and off-peak prices, the system has never been fully tested and integrated. PSNH's CIS system is currently scheduled to be replaced in 2008 (with a 90% confidence level) as part of the NU Customer Services Integration (CSI) project with a new C2 billing system, described in more detail below.

Q. Will the new C2 billing system have the ability to bill the energy component on a time-differentiated basis?

A. Although the new billing system will have the foundation to adapt to handle time-differentiated pricing without shoulder periods, that enhancement will not occur until the core systems are installed and stabilized. While it may be relatively simple to adapt the C2 system to bill energy under on-peak and off-peak prices, we will not be certain of that ability until the system is operational.

The ability to implement a more sophisticated rate design that includes shoulder periods or other requirements must wait until the initial roll-out of the new billing system. Even then, it would require significant additional programming to include substantial system interfaces to accommodate data communicated from new meters.

Q. Do you have an estimate of the cost of performing such programming?

A. As in the case of developing an estimate of the cost for modifying the LPB system, it's not possible to accurately estimate the cost of modifying the C2 system without knowing the specific business requirements. However, based on prior IT projects of this magnitude, a rough estimate is that it would cost $12 million to $24 million, and would not be available until 2010 at the earliest.

Q. What is the current status of the CSI project with respect to a new billing system?

A. The new C2 billing system is currently under development as part of the CSI project, with an initial implementation scheduled for 2008. As with any large project, change control is a critical success factor, so in order to effectively manage changes for the duration of the CSI project, a formal change control process (called "degrees of freeze") was developed and instituted. The CSI project is currently in the 5th degree "lock down" phase relative to billing system changes. The lock down phase is necessary to allow C2 integrated acceptance testing to be conducted in a controlled environment and is directly tied to the system approval for production implementation. Any changes introduced to the C2 system during the lock down period directly increase the probability of invalidating thousands of hours of dry-run testing, will cause a delay in the implementation of C2, will decrease the probability of successful implementation, and will increase the cost of the project. Billing system modifications of the scale and scope of time-differentiated energy service pricing during the lock down phase would be very problematic for PSNH and the CSI project during the in-progress integrated acceptance test phase and the upcoming system certification, production implementation and post-implementation support phases. Once C2 is implemented, there is expected to be a multiple month stabilization period to remediate any system exceptions discovered as part of the production implementation.

Furthermore, IT and business resources are currently dedicated to the CSI project with only a very small IT and business staff in place to keep PSNH's existing billing systems operational (i.e., "break/fix" work and data value type pricing changes). Additionally, due to the high learning curve associated with billing systems in general, IT and business resources are not readily available in the market place, thus further compounding the resource constraint issue.

Q. What are the risks, if any, of implementing a two-period time-differentiated rate design prior to the conversion to the C2 billing system?

A. Due to the degrees of freeze mentioned above and the criticality of maintaining the tight schedule for the testing and implementation of C2, the possibility exists that there will be insufficient time to code and test a new two-period time-differentiated rate design for energy service in C2 prior to the system going live. If that were to happen, it could result in the suspension of the rate for at least several months until the rate is fully coded and adequately tested. Alternatively, any customers taking service under the rate would have to be billed manually.

Q. If time-differentiated energy rates were offered to large customers on an optional basis, could PSNH's billing system support this approach?

A. As discussed previously, PSNH's LPB system cannot support mandatory time-differentiated pricing for energy service without significant modifications. However, under an optional approach with a maximum of two shoulder periods, PSNH could perform the billing manually. This effort would involve a moderate amount of programming and analytical work to develop a manual billing application and to account for revenue-related cost components. Extensive testing would be required as well. A very rough estimate of implementing this manual process for optional time-differentiated energy service pricing for large customers would be 4 to 6 months of development at a cost approximately $100,000.

Q. What would be the manpower needs necessary to accomplish the billing under this manual process?

A. While we can not develop precise estimates due to the lack of details of the specific rate requirements, we can roughly estimate the amount of effort involved in a manual billing process. Based on an assumption of billing for no more than two shoulder periods, we estimate that it would take approximately one to two hours of an analyst's time per account per month to complete the billing process, and to complete the updates for revenue reporting and supplier service reporting. If the number of customers opting for time-differentiated energy service rates exceeded ten to fifteen accounts, additional employees would need to be hired to process this billing in a timely manner.

IV. ISSUES ASSOCIATED WITH MANDATORY TIME-DIFFERENTIATED PRICING OF ENERGY SERVICE

Q. Mr. Hall, please discuss the impact on customers that would likely result if the Commission ordered mandatory time-differentiated pricing for energy service for all metered customers.

A. The impact of mandatory time-differentiated prices would vary based on the size of the customer (the class of service). All customers would experience higher electricity delivery prices because of the significant investment in metering and billing systems, as described above. The cost of the required investment would have to be recovered through delivery charges, so customers would be charged regardless of whether they took energy from PSNH or from a competitive supplier. However, we don't know what the effect on the energy portion of customers' bills will be because we don't know how customers would react to mandatory time-differentiated pricing for energy.

Q. Why would the cost impact of mandatory time-differentiated pricing be greater for smaller customers?

A. The cost impact of mandatory time-differentiated pricing would be greater for smaller customers, particularly residential customers, for a couple of reasons. First, smaller customers do not currently have metering capable of differentiating consumption by time of day, so delivery rates would have to be increased to recover the cost of the new metering. Second, metering costs for smaller customers is higher as a proportion of the total bill, thus resulting in a greater relative bill impact.

Q. Have you performed any analysis of whether residential customers could change their consumption habits by a large enough amount to overcome the incremental cost of metering?

A. Yes, we have. Based on PSNH's load research data, approximately 40% - 42% of residential consumption occurs during on-peak hours (7:00 a.m. to 8:00 p.m. on non-holiday weekdays). Average residential usage is about 600 kWh per month. Therefore, the average customer consumes about 250 kWh per month during on-peak periods. During 2006, the average on-peak real time Locational Marginal Price was 6.82¢ per kWh, and the average off-peak

LMP was 5.18¢, a difference of 1.64¢ per kWh.[4] If energy rates were priced to reflect that differential, and if we assume that a customer shifted 100% of their consumption to off-peak periods (which clearly would not be possible), the energy cost savings for the average customer would be $4.10 per month. There would also be capacity cost savings. The average residential customer's peak coincident with ISO-New England's annual peak is approximately 1.5 kilowatts. Assuming a capacity cost of $4.00 per kilowatt-month, the monthly capacity cost savings would be $6.00, again assuming that a customer was able to shift 100% of their consumption to off-peak periods. Total savings would therefore be around $10.00 per month if there were no on-peak usage, which would not even offset the incremental metering cost.[5]

The above analysis does not take into account the effect on the total bill amount over time. If customers shifted a significant portion of their consumption to off-peak periods, there could be longer-term savings to delivery costs as well as to energy and generating capacity costs. Moreover, we don't know what energy prices might be in the future, what the differential between on-peak and off-peak prices might be, or what the cost of capacity will be. Finally, larger residential customers may be able to shift a significant enough portion of their consumption to offset any additional costs associated with metering and billing.

[4] These amounts are at the transmission level and do not include losses. Actual cost at the retail level would be higher.
[5] The customer charge for Rate R-OTOD is currently $11.70 per month greater than the customer charge for Rate R as a result of the higher metering cost.

Q. Please discuss the likely outcome of mandatory time-differentiated pricing of energy service for larger customers.

A. Larger customers would not experience as large a bill impact as a result of metering and billing changes, because the metering is already installed to measure consumption by time of day. [6] However, the benefits cited by the Commission in Order 24,763 of time-based pricing for energy service may not materialize because larger customers have competitive supply options available to them. Unless the Commission was able to require all competitive suppliers to implement time-differentiated pricing, larger customers would be able to avoid time-differentiated pricing by selecting a competitive supplier who offered a flat rate for energy service. Consequently, there may be no "demand response [as a] cost-effective alternative to…adding to transmission and/or distribution capacity..." Moreover, large customers who are risk-averse with respect to time-differentiated pricing would seek a competitive supplier as an alternative to energy service from PSNH. Such customers would likely be willing to pay a premium above what they would pay under a non-time-differentiated Default Energy Service price (which would no longer be available) to avoid the risk associated with mandatory time-differentiated pricing. Therefore, mandatory time-differentiated pricing could actually increase the cost of doing business in New Hampshire for many customers due to the premium that they would pay to avoid such pricing. While some might argue that this might be a means to stimulate the competitive market

[6] This assumes that a mandatory time-differentiated pricing requirement would not include any requirement to transmit pricing information or other types of data to the customer via the meter. If additional requirements were imposed beyond what the current metering is capable of measuring, the costs for larger customer could be significantly higher.

in New Hampshire, it simply doesn't make sense to implement a policy that could increase costs for New Hampshire's business community.

V. ISSUES ASSOCIATED WITH MANDATORY REAL TIME PRICING OF ENERGY SERVICE

Q. Please discuss the issues associated with mandatory real-time pricing of energy service for all metered customers.

A. Mandatory real-time pricing of energy service poses similar obstacles as mandatory time-differentiated pricing of energy service. The same metering and billing issues that apply to mandatory time-differentiated energy service pricing also apply to mandatory real time pricing. Beyond this, as discussed earlier, PSNH's metering equipment is not capable of transmitting pricing information to customers.

Q. Are there any existing customers who provide response to real time price signals?

A. Yes, there are. PSNH offers a voluntary interruptible program (Rate VIP, also known as "PeakSmart") for large customers. Under that program, customers who agree in advance to provide demand response are asked to do so when the Locational Marginal Price is high or when ISO-New England is near an annual peak. This program is effectively a "reverse" real time price program in that PSNH compensates customers for reducing load during hours of high energy prices or load levels. PSNH requested interruption from customers on two occasions this past summer, and the response rate was roughly 50% (i.e., the amount of load interruption provided by customers was about one-half of the total amount of load customers had indicated they would interrupt). Our conclusion from this limited experience is that customers may not be able to fully respond to price signals despite their best efforts at doing so. That being said, we believe that Rate VIP is still a worthwhile program in view of the relatively low cost of administration and the significant benefits that it can produce.

VI. RECOMMENDATIONS ON TIME-DIFFERENTIATED PRICING

Q. What are PSNH's recommendations on time-differentiated pricing for energy service?

A. Time-differentiated pricing for energy service should not be mandatory for any customer class, in view of the costs of metering and billing associated with such service as described above. However, time-differentiated pricing should be offered to larger customers as an optional service. The number of customers allowed to take optional time-differentiated rates should be limited, since it will be necessary to bill such customers manually in order to avoid the high costs associated with revising PSNH's billing system to accommodate time-differentiated energy pricing. The incremental cost associated with manual billing could be recovered through a monthly administrative fee for customers who elect time-differentiated pricing for energy service.

For smaller customers, time-differentiated pricing for energy service using only two pricing periods (on-peak and off-peak) could be offered and could be billed under PSNH's existing CIS system. Customers taking such service would be assessed a higher customer charge to recover the incremental cost of metering. There is also the risk, described above, that the C2 system may not be able to immediately bill energy service under time-differentiated pricing. If that were to happen, then PSNH would manually bill such customers until the C2 system was capable of doing the billing, or the availability of the time-differentiated energy service pricing would have to be temporarily suspended.[7]

Q. In Order No. 24,763, the Commission expressed a concern that if time-differentiated energy service rates were optional instead of mandatory, then only those customers who stand to benefit from time-differentiated rates would select that option, which could lead to higher peak demand and higher overall energy service rates than would otherwise occur. Could you address this concern?

A. Certainly. We do not believe that historical consumption patterns are necessarily a good indicator of which customers will select the time-differentiated option for energy service. We believe that large customers who elect time-differentiated pricing would be those customers who are relatively

[7] Since we don't know what the response rate to time-differentiated pricing will be, we can't predict whether we would be able to manually bill all of the customers who are taking service under time-differentiated prices for energy service. If that number were sufficiently large, it might not be possible to perform manual billing and the availability of the pricing option would have to be temporarily suspended.

sophisticated users of energy and who have in place energy management systems or programs that enable them to control their energy usage. Therefore, we believe that customers who elect this option will make an effort to consume less energy during on-peak periods and more energy during off-peak periods in order to save money. However, even if only those customers who stand to benefit from time-differentiated pricing selected that option, one could argue that those customers are already consuming a significant portion of their energy during off-peak periods, and are therefore subsidizing all other customers who take energy service under non-time-differentiated pricing.

With regard to the concern that optional time-differentiated pricing of energy service could lead to higher peak demand, we don't believe that would occur. Even if one were to assume that only those customers who would benefit from time-differentiated energy pricing will select that option, the result would be slightly higher prices for the non-time-differentiated customers. Peak demand would be unaffected because consumption patterns would remain unchanged.

VII. RECOMMENDATIONS ON REAL TIME PRICING

Q. What are PSNH's recommendations on real time pricing for energy service?

A. PSNH recommends that real time pricing, if offered, be an optional service. Because of the significant billing issues for real time pricing and the anticipated very small demand for such service, PSNH would manually bill any customer who selected real time pricing for energy service. As in the case of optional tine-differentiated pricing, the number of customers would have to be limited due to the need to bill such customers manually. The incremental cost of manual billing would be assessed to customers each month as an administrative fee. Moreover, because PSNH's metering equipment is not capable of transmitting pricing information, the customer would be responsible for monitoring the real time price. Real time pricing information is readily available over the internet, so this requirement should not pose an insurmountable problem for customers.

VIII. OTHER RECOMMENDATIONS

Q. Does PSNH have any other recommendations for the Commission?

A. Yes, we do. We recommend that the Commission establish a working group to address issues surrounding Critical Peak Pricing and to determine whether a Critical Peak Pricing rate offering should be implemented. Critical Peak Pricing is a pricing mechanism in which energy service is priced higher during hours when energy prices are very high. There are a relatively small number of hours during the year when prices are exceptionally high, and those hours are the most important hours to focus on to reduce energy costs. In 2006, there were 254 hours when the real time Locational Marginal Price exceeded $100.00 per MWh, 42 hours when the real time LMP exceeded $150.00 per MWh, and 17 hours when the real time LMP exceeded $200.00 per MWh. Over the last several years, PSNH has made efforts at its generating plants to ensure a high degree of availability during these high priced hours, thus minimizing supply costs. If a demand-side program can be implemented which produces a significant reduction to load during these hours, the savings to customers could be substantial.

We also recommend that a working group be established to explore rate design issues associated with time-differentiated pricing and real time pricing of energy service. There are several issues that need to be resolved such as the appropriate time periods to use for on-peak and off-peak pricing, recovery of fixed costs associated with generation[8], reconciliation of marginal costs with average costs, recovery of revenue requirements, and the inclusion of capacity costs in real time prices. We believe it is more productive to engage in a collaborative effort to resolve these issues rather than filing testimony, conducting discovery and litigating rate design issues.

IX. SUMMARY

Q. Please summarize your recommendations.

A. We recommend that the Commission:

- Implement optional two period time-differentiated pricing for energy service for all metered customers once billing issues have been addressed
- Implement real time pricing for energy service on an optional basis for larger customers,

[8] Such costs include items such as return, depreciation, taxes, maintenance and non-variable operating expense.

- Create a working group to explore whether Critical Peak Pricing is feasible and whether it should be implemented
- Create a working group to collaboratively resolve rate design issues surrounding time-differentiated pricing and real time pricing of energy service
- If the Commission decides to implement mandatory time-differentiated energy service prices for all metered customers, then technical sessions should be convened to explore the type of metering technology needed to accommodate that pricing, the time frame and cost associated with modifying metering and billing systems, and the manner in which utilities will receive recovery of the cost of metering and billing system modifications.

Q. Does this complete your testimony?

A. Yes, it does.