NHPUC Docket No. DE 06-061

Bibliography on Demand Response, Advanced Metering and Time of Use Rates

Public Service Company of New Hampshire

Comments and Excerpts re: Publications

1. Publication: Deciding on "Smart" Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005. Prepared for: Edison Electric Institute.Prepared by: Plexus Research, Inc., September 2006.

Forward, page ix:

"The Act, per se, does not require that utilities do anything. It requires that the regulators of regulated utilities, and the Boards of Directors of unregulated utilities, shall "consider and determine" what, if anything, the utilities in their jurisdiction must do to comply with the objectives of the Act."

"On one level, the Act's treatment of alternative rates, demand response and "smart metering" may seem simple and straightforward. But the Act creates some potentially burdensome deliberations and financially intimidating requirements for many utilities. The devil is in the details. Many utilities already have time-of-use (TOU) rates, have offered them since PURPA 1978 or even before that time, and still offer these rates. Many utilities have already made large investments in advanced metering systems, some of which are "smart" and others of which are not. Many utilities have offered TOU rates and have found that a large majority of customers are simply not interested unless they are "free riders" who will pay less without altering their consumption patterns."

"For all their similarities, it remains true that no two utilities are alike. This is never more certain than in consideration of PURPA. Fortunately, PURPA allows individual consideration before a determination is made. That consideration will address the significant differences among utilities in their needs, past practices, installed metering, rate design factors, customer preferences and dozens of other factors that come into play. This is a complex matter having major long term impacts on the utility and its customers."

Executive Summary, page xii:

"AMI costs are more easily determined, and typically include the following elements: AMI system hardware & software, new meters and meter-related utility equipment and labor, installation management and labor, project management, and IT support and integration. Costs for automated remote meter reading are approximately $100 to $175 per meter. Adding demand response components (e.g., customer signaling, load control, other demand response equipment) adds another $100 to $350 per site."

Executive Summary, page xiii:

"The rate treatment accorded to the un-depreciated value of legacy meters can be a significant factor in AMI decisions. Also, the potential for significantly different depreciable lives of meters versus the communication modules that may be integrated in advanced meters can be problematic."

Executive Summary, page xiv:

While the AMI process is ultimately about making technology choices, it is imperative that functional requirements be defined and valued before any consideration is given to specific technologies.

Background and Selected Drivers, page 5:

Some states mandated Time-of-Day (TOD) rates and scrutinized the economic foundations of those rates. In other states, TOD rates were composed that were prominently disadvantageous to most customers and were scarcely promoted. This predictably resulted in low levels of initial participation followed by poor retention of those that did sign up.

Background and Selected Drivers, page 7:

Many of the PURPA 1978-inspired voluntary TOU programs actually reached their zenith of participation in the mid 1980s, and then began to decline. One large utility in the Northeast reported a peak TOU participation of 26,500 customers in 1985, dropping to less than 100 today, 20 years later.

Why have so many utilities lost their enthusiasm for TOU rates? Why do so many utilities that have TOU rates available now have so little participation? Is it the rates? Is it the inconvenience of adjusting life to the utility's clock? Is it lackluster promotion by the utilities? Many utilities contend that their residential customers have very little enthusiasm for TOU rates. Others point to a "wear-out" sentiment that appears after a few years of dealing with more complex rates. From a customer's perspective, at least five factors influence their view of TOU rates:

- *Prices: How much can I save? How costly is energy during peak or shoulder periods compared with off-peak? How does that compare to the flat rate?*
- *Duration of peak periods: How long are the high priced periods? If the peak is just a couple of hours wide, it is obviously much easier to deal with than peak periods of 6-8 hours or more. So, is it reasonably convenient for me to make adjustments to consumption, or is it so inconvenient that it really isn't worth the bother?*
- *Understandability: Do I resent having to be mindful of the timing of so many aspects of daily life? Does this add complexity and uncertainty when I would rather be simplifying my life?*
- *Opportunity to control: Can I opt to use the higher cost energy?*
- *Feedback: What information will I get that helps me understand the choices I am making with respect to when and how much energy I use?*

Customers that can respond to a TOU rate by shifting or eliminating some peak period consumption usually expect to save money, compared to what they were paying under the former "flat" rate. They know that getting this saving may involve some inconvenience or discomfort. Operation of the electric dishwasher or clothes dryer may have to be delayed until later. The air conditioning thermostat may be set higher. The pool filter pump may be on a timer. If, after a few years, the customer finds that all his effort, with all the added complexity to his already-complicated life, saves only a few dollars each month, he may decide that it simply isn't worth the bother. And if he gets lax in disciplining his energy consumption he may realize that he is actually paying more than he would on the "flat" rate. He drops off.

Advanced Metering Justification, pages 24~25:

When including AMI costs in a business case, it is important to include all the costs. The largest and most obvious cost is the amount paid to the AMI system provider(s). But other costs will affect the business case as well. Costs include:

- *AMI system hardware & software*
- *New meters, and meter-related utility equipment and labor (e.g. calibration) for both new and redeployed meters*
- *Installation management and labor*
- *Project management by outside contractor (or allocation of internal funds for project management by utility staff)*
- *IT integration by outside contractors (or allocation of internal funds for IT integration by utility staff)*
- *Utility internal costs, such as for facilities, project management, distribution equipment, installation labor, or additional IT support and integration*

When including costs in an AMI business case, it is important to assure that corresponding benefits are included as well. For example, AMI IT costs are usually offset to some degree by avoided IT costs related to manual reading, typically including IT support for handheld terminals and related license and software maintenance fees.

Costs for meters and meter communication systems have been declining slowly for many years, reflecting the general decline in electronic product costs. At this time, costs for automated remote meter reading (that is, not including demand response functions such as customer signaling, load control or other demand response equipment) are approximately $100 to $175 per meter, including meters, all installation, and integration only with the monthly billing process. These figures are shown in Table 1 below. Values for walk-by/drive-by meter reading are shown for perspective.

Installed costs for demand response components vary widely and may be from $100 to $350 per site for signaling and control of a first load, plus about $100 per additional load managed. (Note that traditional direct load control is less expensive, but does not give the customer a role in the control, and is not considered "demand response" in the context of the EPAct.)

Table 1: Approximate AMI System Costs

AMI System Type Cost	***($ per meter)***
Walk / drive-by (radio)	*$50 - $90*
Radio fixed network	*$100 - $160*
Power line fixed network	*$110 - $175*

Notes

- *Figures shown include hardware, software, installation, integration with billing only, training, & vendor deployment support.*
- *Costs vary widely; figures shown are approximate, middle-of-range, for estimating purposes only.*
- *Actual values will vary substantially with size of project, geography, customer density, functional requirements, meter inventory, corporate strategy, & many other factors.*
- *Drive-by does not always cost less than fixed network. A power line system may cost less than a radio system.*
- *O&M costs are not shown, vary widely, and appreciably affect annual net benefit.*
- *Product status, risks, performance & other factors vary widely & often have cost & benefit consequences.*

Assumptions

- *Saturation deployment.*
- *Typical mix of single-, network-, & poly-phase meters.*
- *50/50 meter retrofit/replacement.*

Economic & Technical Implications of Technology Choice, pages 37~38:

We observed elsewhere in this Guide that many utilities dived into TOU metering after PURPA 1978, only to find that after five or ten years the level of residential participation in voluntary TOU had fallen steeply. Clearly, the customer will decide whether he prefers the utility's "flat" rate or TOU rate, and whether the savings in TOU are worth any inconvenience they may require.

This brings us to the critical importance of the rate design to the sustainable level of participation in a voluntary residential TOU rate. Clearly, dramatically higher on-peak rates are more challenging than rates with smaller on-peak/off-peak differentials. Similarly, a TOU rate with long on-peak period is much more difficult to live with than a short "spiky" peak period. A weather sensitive peak period in *southern states, hot with high humidity, may begin in mid-morning and extend late into the evening.*

A detailed discussion of rate design considerations is outside the scope of this Guide. It is sufficient to state here that the initial level of participation in TOU rates by residential customers, and their retention over five or more years is very much a function of the TOU rate design, the consumer's ability to control consumption during high cost periods, and the other alternatives that are available.

The classical single-register induction Watthour meter for residential service costs between $20 and $30 new. The modern solid state electronic version of this meter will be in the same price range. Any technology chosen to implement TOU or dynamic rates will increase the cost at that location, whether it is simply a more competent meter with an optical port for manual data retrieval, or whether that meter is part of a full-function two-way fixed network.

Historically, many utilities assessed a special "metering charge" for the more costly and complex meters. That meant that a TOU customer might alter his consumption and save, perhaps $8 a month. But if there is a special metering charge of $6, the net saving to the consumer is only $2. That customer may rapidly lose interest! This problem with the impact of the metering charge was one of the factors that "sank" the large Puget Power TOU installation. Utilities must consider this matter carefully.

Economic & Technical Implications of Technology Choice, pages 39~40:

Value of In-Service Meters

One crucial aspect of the economic justification of AMI systems is easily overlooked until late in the game. It can influence a utility to reject an otherwise positive business case. It is the accounting treatment of the value of in-service meters.

Some or all of the existing meters in the field may be replaced with new meters. But meters removed from service are likely still "on the books," and their undepreciated value becomes a write-down, that is, a loss. From a book or net income perspective it appears as an AMI cost which can have a significant impact on reported income. This write-down may impact regulated income as well unless there is an appropriate regulatory treatment of this issue.

The book value of in-service meters is often substantial because meters have a long life in service and on the financial books. Meters are normally entered into the books at their installed cost, typically something between $50 and $65 per meter for a simple residential kWh meter. This usually includes the purchase cost of the meter, the utility's cost of receiving, testing (if any), handling, and installation at the customer premise. A meter that is capitalized at $60 and depreciated in a straight line over 30 years will have a book value of $20 after 20 years of service. If this meter is replaced (rather than retrofitted) during an AMI deployment, the utility incurs a write-down or a "loss" of $20. This can be a very significant addition to the AMI system's cost-per-meter, which may range from $100 to $200.

This effect on book and regulatory income can be a major driver of the AMI approach. Utilities that must incur this "loss" in the year the meters are removed from service may look to retrofit AMI communication devices to existing meters and redeploy them.

In the bigger picture, many utilities conclude that new technology has rendered induction meters obsolete, and-if the write down of the book value can be dealt with-it makes little sense to retrofit those meters with communications and return them to the field.

The issue of depreciation of new meters takes on a new meaning in the context of AMI systems. Many utilities traditionally depreciate "communications equipment" on a much shorter schedule (perhaps 7 years), than meters (perhaps 30 years.). But if we install communications in the meter, which schedule should pertain? The communication and metrology functions are closely integrated in most new solid state meters. It is unlikely that, after 10 years, the meter can be retrieved from the field, the communications section removed and replaced, and the meter sent back to the field. This may be technically possible, but it is economically unattractive. A need to harmonize the actual and depreciable lives of the meter and its communications is emerging as electronics now replaces the moving parts and gears of the induction meters. Most current practice projects a 15 to 20 year life of the solid state meter with its communications.

Customer Gateways

If a utility can communicate with a meter, if it can send commands and programming instructions to the meter, and if that utility can receive meter data and information on outages, tamper, load profiles, voltage and other information from the meter, then what else can be done with this capability? What about sending weather forecasts, stock quotes or baseball schedules, or receiving intrusion or fire alarms? It is an intriguing thought. It is an idea that has attracted many competent technology firms-and put them out of business. Technology is not the problem. The difficulties arise from:

- *The higher first cost of the equipment*
- *The spotty level of customer acceptance*
- *Their willingness to pay for additional services*
- *Problems with using the meter as a portal through which to deliver these services*
- *Cross-subsidy issues*

This is not to say that there may not be some future role for utility metering in gateway enabled services. But meter data are of relatively low value. It is more likely that meter data will ride on a communications platform designed for other, higher-value services than the other way around. The market has spoken on this issue many times in the past 35 years, leaving many well intentioned-and now defunct-companies in its wake.

Best Practices in Purchasing, Installation & Integration, page 41:

Most utilities are tempted to begin assessing metering and AMR/AMI options by first seeing what is available for technology. That is not difficult, because every utility is constantly besieged by vendors asking to come in to present a “dog and pony show.” This does not seem unreasonable at first glance, and it is useful to become familiar with the capabilities and limitations of available systems. But it is a mistake to begin a technology selection this way. Technology and vendor assessment must come later. Too often, one or more members of the AMI team fall in love with a technology or a vendor without a full understanding of what is to be accomplished. That dramatically confuses the process of selecting the most suitable technology and approach. The first step after the vision is always to carefully and objectively define the requirements for a system that supports the vision.

2. Publication: Assessment of Demand Response & Advanced Metering. Prepared by: Federal Energy Regulatory Commission, September 2007.

Executive Summary, page ii:

Advanced metering can enhance an electric customer's ability to reduce demand in response to a higher price and an electric utility's ability to meter and monitor the customer's electricity use. Such metering can also allow an electric utility to provide a variety of innovative services to benefit customers and to reduce the utility's costs of operations.

PSNH Comments:

The use of "can" (and "may" or "could") is typical of authors trying to favorably present the conceivable benefits of advanced metering, time differentiated pricing programs, demand response programs, etc. It is very different than stating such metering will provide desirable benefits. In some cases, real benefits may be achieved. However, actual benefits are highly dependant on many other factors – not the enabling technology of the metering system. The more important factors include:

- Pricing structure
- Customer acceptance
- Availability of significant, controllable, discretionary loads such as central A/C – often unique to warmer areas of the country
- Inconvenience or complexity of program
- Actual costs/savings vs. anticipated costs/savings
- System reliability
- Costs to implement and maintain "enabling" technology
- System supplier longevity and/or technological obsolescence

These factors should be carefully considered before investing in expensive technology. The investment should not be made unless there is a high probability of a reasonable return on that investment.

Demand Response, page 21:

Continuing barriers to implementing critical peak pricing tariffs

Critical-peak pricing (CPP), a time-of-use rate which includes an extreme price to be used either during system emergencies or periods of high wholesale prices, dramatically reduced peak demand and was acceptable to smaller customers during a statewide pricing pilot in California.[113] While the number of utilities which have announced plans for CPP programs has increased, they are reluctant to rely on elasticity data which came exclusively from the California pilot results, and many still feel they first need to conduct pilots to test customer response in their own service territories.[114]

Advanced Metering, page 27:
Developments in Advanced Metering

Since last year's Commission staff report, AMI gained support from a number of initiatives. For example, at its 2007 Winter Meeting, the National Association of Regulatory Utility Commissioners (NARUC) issued a resolution that recognized the benefits of advanced metering. The resolution calls for elimination of barriers to advanced metering and recommends that state commissions provide investment incentives and accelerated depreciation to help utilities quickly recover their advanced metering investments.[134]

EPAct 2005 PURPA Metering Assessments

Section 1252(b) of EPAct 2005 added a new section 115(i) to the Public Utility Regulatory Policies Act of 1978 (PURPA)[135] *that requires states to investigate demand response and time-based metering. Section 115(i) of PURPA states that "each state regulatory authority shall conduct an investigation and issue a decision whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time based pricing rate schedules and other demand response programs." Section 1252(b) also requires states to report their findings to Congress by August 8, 2007.*

By July 2007, most states had open proceedings to discuss the EPAct provisions. States, such as Ohio, commenced comprehensive proceedings to examine the advanced metering PURPA standard. Other states, such as California, did not institute a specific PURPA proceeding, but have been engaged in detailed, ongoing proceedings relating to AMI. Twelve states have concluded their proceedings, with two deciding that it was appropriate for their utilities to provide and install time-based meters. Another 11 opted to not require it. Information on the activities of state regulatory agencies in response to EPAct 2005 is included in Appendix E.

Advanced Metering, page 34:
Issues and Challenges -- Deployment Decisions

AMI implementations come with a significant price tag, even as the cost of the advanced meters themselves continues to decrease. This is especially true for large and full-featured AMI deployments. Furthermore, utilities and their regulators are faced with evaluating a number of alternative metering products, network configurations, and deployment strategies in designing and evaluating AMI systems for cost-effectiveness over the life of the meters. Pilots or test-phase deployments continue to be used extensively to assess costs and benefits and to allow both utilities and their customers to test and "try out" various AMI products, configurations, and features.

Interoperability and Open Standards

As discussed in more detail in last year's Commission staff report, there are technology standards on common functionality of AMI systems. In particular, ANSI standard C12.19 (Utility Industry End Device Tables) enables metering data and data tables to be transferred from one computer application and system to another. The next standard, ANSI standard C12.22 (Protocol Specification for Interfacing to Data Communications Networks), which would enable C12.19 metering data structures to be shared over any combination of "physical" network media,[170] *is pending.*

Since last year's Commission staff report, utilities looking to deploy AMI with HAN-connectivity have focused attention on how to configure HAN to AMI systems connections.[171] *HAN connectivity represents a new opportunity for advanced metering, but also introduces a new issue. The heart of the issue is whether the utility-owned meter should serve as the connection (or "gateway") to the HAN, or whether AMI-based gateways only serve to exclude competitive third-party HAN solutions. In other words, deploying advanced meters with grid-to-HAN gateway switches makes those gateways part of the utility-provided metering solution. Some AMI consultants as well as HAN solution vendors argue that third party HAN connectivity solutions do not need utility-based advanced meter gateway switches.*[172] *Proponents of utility-based gateways, on the other hand, argue that utilities are best positioned to provide meter-to-HAN connectivity services and that use of these gateways allows needed central administration and verification for load control and demand-response purposes, e.g., "to provide Critical Peak Pricing (CPP) and other emergency event customer notifications.," "…provide better confirmation that these notifications were both sent and received," and "significantly reduce the need to outsource such communication activities to third party providers."*[173]

3. Publication: <u>Assessment of Demand Response & Advanced Metering</u>. Prepared by: Federal Energy Regulatory Commission Staff, August 2006.

Chapter II – Background on Demand Response, Page 13:
Evidence of Customer Price-Responsiveness

Offered time-based rates, customers choose whether to adjust their consumption or not. Their decision to adjust consumption is driven by the costs and benefits of taking one of the following actions: (a) adjusting routine business activity specifically to avoid paying higher than average prices; (b) forgoing discretionary usage; and (c) deploying distributed or on-site generation. The ability of customers to respond to prices requires the following conditions: that time-based rates are communicated to them; that they have load control systems that allow them to respond to price signals (e.g., by shedding load, automatically turning appliances down or off, or turning on an on-site generator); and that customers have meters that can measure *consumption by at least the time of day so the utility can determine how much power was used at what time and bill accordingly. Participants reduced load 13 percent on average, and as much as 27 percent, when price signals were coupled with automated controls such as controllable thermostats.*

Chapter II – Background on Demand Response, Page 14:

Role of Enabling Technology

A key requirement for most demand response programs and time-based rates is the availability of enabling technology. For states or utilities to implement demand response and time-based rates, customers would need meters that record usage on a more frequent basis, preferably hourly.

Chapter III – Advanced Metering Penetration, Pages 33~34:

Costs of Deploying Advanced Metering

The total capital cost of deploying AMI has not declined significantly even though the AMI and meter vendor revenue per meter has gradually declined by approximately 23 percent over the past 10 years. The total capital costs of deploying AMI include the hardware costs (meter modules, network infrastructure, and network management software for AMI system), as well as installation costs, meter data management, project management, and information technology integration costs. Examination of data obtained on 10 large AMI deployments over the last decade, suggests that AMI hardware costs have decreased during this time period. This trend can be seen in Figure III-11.

In the late 1990's, the hardware costs per meter averaged $99.[74] *By 2005/2006, the average hardware cost per meter had decreased to $76. The capital costs of installing the AMI communications infrastructure, in contrast, have stayed relatively constant except for the deployment at Jacksonville Electric Associates in 2001 (which included water and electric meters), generally bound by $125 per meter on the low end and $150 on the high end. Table III-4 below shows the hardware and total detailed data on each of the 10 deployments.*

There is considerably more expense and capital investment involved for a successful deployment of AMI than metering and AMI system components. Deployment costs include:

- *Project management*
- *Installation of meters and network*
- *Meter data management*
- *Information technology integration costs with meter data management and other systems*

For the AMI deployments where both the hardware costs per meter and the total AMI capital cost per meter were available, the hardware costs per meter represented as low as 50 percent and as high as 70 percent of the total AMI capital costs. …

Chapter III – Advanced Metering Penetration, Pages 38~39:

AMI specifications

Most requests for proposals (RFPs) from electric utilities now include a requirement for delivering interval data, at least hourly, for all meters connected to the network on a daily basis. The requirement for interval data for all customers is relatively new, and reflects the increased functionality and performance of AMI products on the market. However, billing and settlement requirements in organized wholesale markets may influence what utilities specify in their RFPs. If wholesale settlement is based on 15 minute interval profiles, utilities may be more likely to ask for 15 minute intervals for all customers. While the need to support time-based rates may prompt regulators to support an investment in AMI, the requirements for AMI are usually based on other considerations, such as operational efficiencies and wholesale settlement. Consequently, consistent AMI specifications may be difficult to achieve in the near-term.

Chapter IV – Existing Demand Response and Time-Based Rates, Page 56:

Puget Sound Energy

(PSE) began a TOU pilot in June 2001; it installed new meters. PSE enrolled 240,000 customers who moved from flat rates to its TOU program. During the mid-day period (10 a.m. to 5 p.m.), TOU customers paid the same amount (5.8¢/kWh) as those on flat rates. Morning (6 a.m. – 10 a.m.) and evening (5 p.m. – 9 p.m.) periods were priced only one cent higher. Enthusiastic customers achieved five-to-six percent peak reductions, and conserved 5 percent in the first year. PSE instituted a $1/month charge to recoup part of its metering costs in July 2002. This substantially cut into customer savings. In the fall of 2002, customers began receiving cost comparisons of TOU bills with what they would have paid on flat rates; 90 percent were saving less than the metering charge. Washington state discontinued the TOU pilot in November 2002.

Chapter IV – Existing Demand Response and Time-Based Rates, Pages 73~75:

Boom-bust nature of demand response

A fundamental challenge with incentive-based demand response is the boom-bust nature of electric markets. The use of incentive-based demand response is largely concentrated during periods of tight supplies or reserve shortages. When generation is plentiful, the need for these programs is less, with consequent reduction in payments – either through reduced capacity payments or through infrequent usage. This overcapacity situation exists today in many parts of the country. As a result, customer interest may atrophy and demand response programs are likely to be mothballed or terminated in these regions. However, when supply and demand become tighter, the stock of available demand response resources may not be adequate.

Customer inertia/desire for simplicity

Most customers (particularly residential ones) will be resistant to programs if they require effort, such as when the basic design of the program is not simple. Focusing these educational efforts first on the largest customers will allow these customers to adequately assess the rewards and costs associated with participation in demand response programs. Experience in other states such as New York and California (which use some system benefit funds for customer education) has shown that targeted customer education and training increases participation and response rates.

Need for simple and fair time-based pricing

The principles of simplicity and fairness are keys to the success of real-time programs. UtiliPoint found that "as long as customers are convinced that utility-posted prices are fair and reflect actual system circumstances, and are based on competitive markets, they will accept them as the basis for time-varying rates."[164] *This seems to be a common refrain from satisfied customers. Customers notified by various means about daily prices and price spikes achieve better responses and are more satisfied with the programs. Both in re-regulated electricity markets and traditional utility territories, multiple notification channels (such as toll-free numbers, pagers, cell phones, and the Internet) increase success rates of RTP programs. Customers' use of programmable communicating thermostats is important for easier response to these rates.*[165]

Mandatory vs. voluntary participation in price-based programs

Experience has shown that when participation in price-based programs is voluntary, the level of customer participation and aggregate load reductions have been modest.[166] *Voluntary TOU or RTP programs with opt-in can create a self-selection bias problem from the perspective of some LSEs: customers who know they already use less at peak enroll, while those who use more at peak but who may not want to risk shifting or paying higher peak prices do not. Thus, little or no load is shifted from peak, defeating the purpose of the program. In addition, since most voluntary time-based rate programs are designed to be revenue neutral (i.e., on- and off-peak rates designed to collect the same revenue as the non-TOU default tariff from a hypothetical customer), customers with below average on-to-off-peak consumption ratios are free riders who can reduce their bills by taking the TOU rate option without changing their consumption behavior. The revenue shortfall can have undesirable consequences and possibly create revenue losses for LSEs.*[167] *Customers tend to stay in voluntary programs with clear opt-out options. Customer responses to well-designed, simple programs they perceive as fair are high: they want to stay in the programs, and felt they achieved savings and control. Experience in California suggests that customers especially like dynamic pricing programs that pair automated customer technologies. Customers with access to smarter appliances and systems thought they became more aware of their energy use and costs as well as their routines at home and at work.*

Chapter IV – Existing Demand Response and Time-Based Rates, Page 77:

Another key development is that third-party providers have emerged whose only business is to maximize demand response and use related technologies. They aggregate and deliver load-response to markets, and have skills needed to monitor energy markets and prices. These third parties provide a valuable service to customers, because many large consumers have limited expertise or experience with aggregating or managing demand response, especially in markets. An Lawrence Berkeley National Laboratory survey showed that 70 percent of business managers in Niagara Mohawk's RTP program rarely or never monitored next-day hourly prices; only 17 percent consulted prices routinely; 13 percent only checked day-ahead hourly prices when other signals (such as NYISO events or very hot weather) suggested they would be high.[184] Most businesses monitor their <u>own</u> business, not the energy business.

Chapter VI – Role of Demand Response in Regional Planning and Operations, Page 121:

Demand response programs often find that they must accommodate voluntary response in order to increase participation. This is not surprising. While the cost of electricity is important to most consumers, it is only one of many costs. Loads often find it impossible to make firm, long-term curtailment commitments because there is some chance that external events (external to the power system) will prevent them from reducing power consumption when requested. Even if a customer is able to respond 99 percent of the time, the other one percent of the time may be perceived to be of such high importance that the load is unwilling to participate in a curtailment program. This reaction is surprisingly universal; it can be true for residential as well as commercial and industrial customers.[271] Day-ahead and hour-ahead hourly markets reduce or eliminate this problem for many large loads and generators. But the transaction burden of constantly interacting with energy and ancillary service markets is likely too great for many small loads. Many will prefer to establish a standing offer for response that they are able to honor the vast majority of the time.

[271] An industrial load may have an unexpected order and consequent production goal. A residential customer may have a sick child at home and be unwilling to allow air conditioning curtailment. Neither event could be predicted in advance and neither event is tied to power system conditions.

Chapter VII – Regulatory Barriers, Page 128:

Without additional technology, customer actions in response to prices, incentives, or directions from grid operators cannot be (a) measured and compensated, or (b) enabled. One study noted that without near universal installation of advanced metering, demand response activity for smaller customers will likely be limited to customers with large loads suitable for load control.[291] Wide-scale upgrading of meters or deployment of advanced metering and other enabling technologies *requires substantial investments and outlays of capital. Utilities are reluctant to undertake these investments unless the business case for deployment is sufficiently positive to justify the outlay. In addition, utilities are concerned about whether meters could become a stranded asset under future deregulation – that is, is there long-term regulatory certainty to their investment?*

As Chapter III noted, the business case for advanced metering can include numerous operational cost savings for distribution utilities, in addition to demand response-related savings. Operational benefits may largely cover much of the cost of the deployment, as well as accelerating its cost recovery. Utilities need to conduct a fair and reasonable cost-benefit analysis of adopting metering infrastructure that takes into account the nature and needs of the service territory.[292] *Recovery of at least part of utility investment in metering, either through expensing or rate-basing, may be necessary. Without cost recovery, utilities may not have an incentive to roll out advanced metering to all customers. As was the case with utility investment in demand response, in order to provide sufficient incentive for utility investment in advanced metering, returns from this investment need to be at least commensurate with returns that utilities can get from their generation and transmission assets.*

Cost recovery of advanced metering in rates has been the subject of regulatory proceedings. Because these deployments may require an increase in rates, it is uncertain whether states will allow full deployments to be fully rate-based, amortized, or expensed. UtiliPoint presented the results of an earlier survey at the FERC Technical Conference (see Figure VII-1) that suggested that most of the regulators contacted supported at least partial cost recovery of advanced metering and demand response. Rate recovery is not without controversy. For instance, consumer groups in California argued against rate recovery of advanced metering in the proceedings associated with statewide deployment.[293]

Until uncertainty about rate recovery of advanced metering can be resolved, and that meters will not become a stranded asset under future deregulation, utilities will be reluctant to invest in the technology.[294] *Similarly, utilities will also need to know whether retail rate regulators will approve a concurrent retail dynamic pricing structure. Utility delay or non-action on advanced metering deployment due to these uncertainties may limit the potential for demand response in the United States.*

Another cost-recovery barrier raised at the FERC Technical Conference is the disconnect between the economic life of advanced metering infrastructure and its accounting depreciation period. Southern California Edison (SCE) reports that "many utilities, including us, are concerned about the potential that AMI technology will not last as long as its depreciation period… Since the ANSI meters and communication networks will have to operate in very difficult environmental conditions over a long time, if the life of these systems falls short, this could result in significant cost impacts for our customers."[295] *Aligning the economic life with the accounting life will remove this disincentive.*

In addition, advances in technology and cost declines associated with metering and controls, in combination with the greater system benefits they now offer, should also help ameliorate concerns about cost-effectiveness.

4. Publication: <u>Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the U.S. Congress Pursuant to Section 1252 of the Energy Policy Act of 2005</u> Prepared by: U.S. Department of Energy (DOE), February 2006.

Excerpt - Page vii:

"Based on this review, DOE concludes that, to date, the estimated benefits of demand response are driven primarily by the quantification method, assumptions regarding customer participation and responsiveness, and market characteristics. Without accepted analytical methods, DOE finds that it is not possible to quantify the national benefits of demand response. Moreover, regional differences in market design, operation, and resource balance are important and must be taken into account. Estimates of demand response benefits are best done for service territories, states, and regions, because the magnitude of potential benefits is tied directly to local electric system conditions (e.g.,the supply mix, the presence or absence of supply constraints, the rate of demand growth,and resource plans for meeting demand growth)."

PSNH Comment: Report recommends large customers for Time of Use pricing but states that midsized customers should be segregated and targeted groups offered time differentiated rates to which they can properly respond.

5. Publication: <u>Dimensions of Demand Response: Capturing Customer Based Resources in New England's Power Systems and Markets.</u> Prepared by: New England Demand Response Initiative (NEDRI), July 2003.

Excerpts – Chapter 3:

"Here, the fundamental premise is that there is a significant amount of demand response that time- and location- sensitive retail prices can inspire. Our essential recommendation is that policymakers should evaluate and adopt pricing structures (and their associated metering technologies) and other policies that will most cost-effectively capture that demand response, and do so in ways that are consistent with other stated objectives, such as consumer protection, economic efficiency, equity, and environmental protection."

"Determination of the cost-effectiveness of advanced metering will require an investigative process of some kind, particularly in the case of lower-volume customers. Determining the acceptability to customers of time-based rate designs will also require an investigative process, although it may make sense to combine this effort with the metering investigation. The public utility state commissions are best suited to these tasks."

"If the state commissions find that advanced metering is not cost-effective for smaller customers, they should examine direct load control programs as an alternative. Similarly, if the state commissions find that direct load control programs offer a greater potential demand response benefit than pricing options, appropriate consideration should be given to the certainty provided by direct load control and to the relative customer acceptance of both direct load control and time-based pricing alternatives."

"Some residential consumers may best be able to contribute to peak demand reduction through energy efficiency programs, rather than through pricing or metering incentives."

6. Publication: <u>Smart Meters, Real Time Pricing, and Demand Response Programs: Implications for Low Income Electric Customers</u>. Prepared by: Barbara Alexander, May 2007.

Excerpts:

"The push to install more expensive smart meters (and their associated communications and data storage systems) and consider more "real time" or volatile electricity prices for residential electric customers has the potential for significant harm to many residential customers and particularly to limited income and payment troubled customers."

"It would be unfair and poor public policy to leap into new metering technology and new methods of pricing essential electricity service to residential customers without careful analysis and access to factual information on the impacts of such proposals on customer bills and usage patterns. The lack of such information is particularly glaring for low income customers."

"... New York previously had a mandatory time of use rate for very high use residential customers. ... the program was so unpopular the state legislature amended the law to make any residential time of use program voluntary. Maine's mandatory TOU rate program... was abandoned ... Puget Sound Energy of Oregon abandoned a system-wide move to TOU pricing for residential customers when it became clear that the additional costs of the new communication and billing systems could not be avoided with average monthly bill savings."

"In general, the overall tend of these initiatives will be to raise electricity prices to pay for the new meters, installation and maintenance of the new meters, new communication facilities, new computers and software to receive and process the information from the meters, and new billing systems to implement the pricing changes." "Since electricity is vital to household and community health and safety, any development that may reduce the affordability of electricity should be viewed with suspicion and alarm."

Study Recommendations:

"Before approving any demand response program for residential customers, the state commission should be required to find, after notice and hearing, that the benefits to all residential customers exceeds the costs associated with the implementation of the program over a reasonable period of time."

"The commission should not approve any demand response program for residential customers that is not voluntary or that is likely to have an adverse impact on residential customers generally or shift costs to those who use less than the average amount of electricity."

PSNH Comments:

The article concludes that the overall trend of TOU and RTP initiatives will be to raise electricity prices to pay for the costs of metering and billing. PSNH made this very point in its testimony. The article further recommends that prior to implementing any demand response program for customers, the state commission should make a finding that the benefits exceed the costs. In PSNH's cross-examination of Staff, the Staff witness agreed that very little information is available on the benefits of TOU or RTP. However, Staff's recommendation is to implement TOU rates on a mandatory basis, notwithstanding the lack of information on potential benefits. This position is in direct conflict with the recommendations in this article, since it would likely result in increased costs for customers. The author also recommends that state commissions should not approve any demand response program for residential customers that is not voluntary or that is likely to have an adverse impact on residential customers generally or shift costs to those who use less than the average amount of electricity. PSNH agrees with this recommendation.

7. Publication: The Role of Demand Response in Default Service Pricing. Prepared by: Galen Barbose, Charles Goldman and Bernie Neenan for The Electricity Journal, April 2006.

PSNH Comments:

- The article states that adoption of RTP has been done more to promote the competitive market than for demand response.
- As PSNH pointed out in testimony, the article concludes that RTP encourages switching to a competitive energy supplier by motivating customers to seek hedged supply contracts at a fixed price to avoid the perceived risk of variable pricing.
- The conclusions in the article support PSNH's testimony that if RTP were implemented on a mandatory basis for PSNH customers, it would increase the cost of doing business in New Hampshire, since PSNH's standard default price is below market. Customers would no longer have a fixed default price (if the standard default price was RTP) and would therefore be encouraged to switch to higher priced, hedged competitive contracts in order to avoid risk.

- The study finds that most customers will leave default RTP and therefore price responsive demand as a result of implementing mandatory RTP may be rather limited. If so, the desired result of reducing system peak would not be accomplished.

8. Publication: Breaking out of the Bubble: Using Demand response to Mitigate Rate Shocks. Prepared by: Ahmad Faruqui for Public Utilities Fortnightly, March 2007.

PSNH Comments:

- This article focuses primarily on the impact of reducing peak demand on the few days per year when the system is at peak. PSNH pointed out in its testimony that there are a relatively small number of hours in which wholesale energy prices are at a very high level, and those are the hours on which load management efforts should be focused.
- The article states that “empirical evidence suggests that the majority of load drop came from a minority of customers.” This statement reinforces PSNH’s position that TOU rates or RTP should not be mandatory for all customers.
- The article states that "Regulators and utilities seriously should rethink their current policies and consider offering some type of dynamic pricing as the default rate for all customers and allowing customers to "opt out" of static, non-time varying rates if they so choose.” This statement suggests that dynamic pricing should not be mandatory, but that customers should have the ability to choose such pricing.

9. Publication: Does Dynamic Pricing make Sense for Mass Market Customers? Prepared for: The Electricity Journal, August/September 2007.

PSNH Comments:

- This articles notes that it is not clear whether dynamic pricing would be attractive to mass market customers in states with colder climates. This statement confirms PSNH’s position in its testimony that smaller (mass Market) customers would likely pay higher prices, especially in view of the cold climate in New Hampshire.
- The article states that savings under real time pricing comes primarily from avoidance of the hedge premium inherent in default service pricing. As stated by PSNH in its testimony, a hedge premium does not exist in PSNH’s default service price, since PSNH charges customers its actual cost of providing service.
- Analyses in the article showed that larger customers could save small amounts, but only if virtually all of their deferrable consumption was shifted to off-peak periods.

- The article concludes that conservation measures (vs. load shifting) are more likely to have an impact on reducing peak usage. PSNH agrees with this conclusion.

10. Publication: <u>How to Get More Response from Demand Response</u>. Electricity Journal, October, 2006.

Page 1:

"Despite all the rhetoric, demand response's contribution to meet peak load will remain elusive in the absence of enabling technology and standardized business protocols."

Section III, How Much DR is Really There?, Page 2:

"Following the passage of the Energy Policy Act (EPAct) in August 2005, there has been renewed interest in smart meters, time-variable pricing, and demand response - the legs of a stool. EPAct's main contribution was two-fold: First, it codifies the significance of enabling technologies, which are prerequisites to wider implementation of DR. Second, it instructs both the Department of Energy (DOE) and FERC to establish baselines and goals for increased reliance on DR."

FERC's main conclusions are that, "The potential immediate reduction in peak electric demand that could be achieved from existing DR resources is between 3 and 7 percent of peak electric demand in most regions," but points out that the low penetration of enabling technologies limits what can be achieved in the immediate future. It is a classic chicken-and-egg problem. Without wide-spread penetration of smart meters and time-variable pricing there is little future for DR.

Section IV, What is the Holdup?, Pages 2-3:

"Given the significant size of the DR resource and its cost-effectiveness, why aren't we seeing more DR deployment when emergencies do occur? Most studies, including the two major reports by DOE and FERC, blame the problem on lack of enabling technology - which certainly is a major obstacle. Without affordable smart meters, reliable and inexpensive two-way communication and widespread use of time-variable tariffs, the true potential of DR will never be realized.

But there are two other highly critical aspects of enabling technology, which remain as serious obstacles to successful and cost-effective implementation of DR, namely:

- ** Fast, reliable, and automated communications among multiple players in the DR domain in real-time, and*
- ** Standardized protocols for customer enrollment and notification, business processes and settlement.*

Unless these two issues are successfully addressed, wide-scale implementation of DR shall remain limited and problematic, especially if there is interest to reach a significant number of small consumers.

Section IV, What is the Holdup?, pages 3-4:

The second problem may not be as obvious but is equally daunting. Since many customers and intermediaries are likely to participate in DR programs, keeping track of who did what and when and how much they are owed as a result of their contribution is currently a back-office nightmare (Figure 4). In many states, including California, there are multiple existing programs offered by different utilities to different customers with widely varied incentives, terms, and conditions.[11] *Record keeping, invoicing, collecting and settlement processes become intractable with thousands or millions of customers and multiple intermediaries.*