NEW ENGLAND DEMAND RESPONSE INITIATIVE

FRAMING PAPER #3: METERING AND RETAIL PRICING

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ACRONYMS

AEM	Advanced Energy Management
AMR	Automated meter reading
BC Hydro	British Columbia Hydro
C&I	Commercial and industrial
CEC	California Energy Commission
CBL	Customer baseline
CVPS	Central Vermont Public Service Corporation
ESCO	Energy service company
ESP	Economy Surplus Power
FERC	Federal Energy Regulatory Commission
GPC	Georgia Power Company
HVAC	Heating, ventilation, and air conditioning
IOU	Investor-owned utility
ISO	Independent system operator
kW	Kilowatt
kWh	Kilowatt-hour
LSE	Load-serving entity
LMPS	Load Management Price Signal
MW	Megawatt
MWh	Megawatt hour
NARUC	National Association of Regulatory Utility Commissioners
NEDRI	New England Demand Response Initiative
NEPOOL	New England Power Pool
NYPSC	New York Public Service Commission
NYSERDA	New York State Energy Research and Development Authority
PG&E	Pacific Gas and Electric
PUC	Public utilities commission
PUGET	Puget Sound Energy
PURPA	Public Utilities Regulatory Policy Act of 1978
RTP	Real-time pricing
RVSP	Residential Variable Service Program
SCE	Southern California Edison
T&D	Transmission and distribution
TOD	Time of day
TOU	Time of use
TVA	Tennessee Valley Authority
VPI	Variable Price Interruptible Power
WUTC	Washington Utilities and Transportation Commission

I. INTRODUCTION

A. Purpose and Challenges

The objective of the New England Demand Response Initiative is to develop a comprehensive, coordinated set of demand response programs for the New England regional power markets. Put another way, NEDRI aims to maximize the capability of demand response to compete in the wholesale market and to improve the economic efficiency and environmental profile of the electric sector. To those ends, NEDRI is focusing its efforts in four interrelated areas: ISO-level reliability programs, market-based price responsive load programs, demand response at retail, and longer-term end-use efficiency programs.

The third area is the subject of this framing paper. To better align behavior in the retail and wholesale markets, the challenge is to determine what policies need to be implemented and what metering and communications technologies deployed to encourage customer demand-response. In other words, what can be done to reveal to customers and load-serving entities (LSEs) the value (cost) of energy savings (consumption) during times of high loads or system constraints?

The paper is divided into several sections. Following the introduction and summary of policy issues is a background section describing the various approaches to retail electricity pricing and the metering and communications systems associated with them. The third section discusses in some detail specific pricing and metering activities in New England and elsewhere in the country. Section IV outlines possible strategies to support retail demand response and some of the policy and technical considerations raised by those strategies. The paper's purpose is not to propose particular courses of action but rather to identify the issues for discussion among the NEDRI participants.

B. Summary of Policy Issues and Options

Section II provides a general background into electric utility rate design and metering. Section III and the Appendix describe the range of retail pricing programs that various utilities across North America have made implemented. Section IV enumerates the major policy issues raised by innovative pricing and metering. We list them briefly here:

<u>Pricing Issues</u>

- *Purpose*. What objectives are new retail rate designs and programs intended to serve?
- *Mandatory or voluntary?* Should a new rate design be mandatory? Mandatory seasonal or time-of-use rates for lower-volume consumers and RTP for large-volume customers could achieve significant savings, but could also impose significant costs upon inelastic users.
- *Low-volume versus high-volume customers*. Price elasticity can vary with total amount of usage in a period. Since for most customers there is a minimum

amount of usage that is unavoidable, at least in the short term (*e.g.*, lighting, HVAC, computing, refrigeration), there is less discretionary demand among low-volume users that can be manipulated through pricing or demand-response programs. What does this mean for the creation of more dynamic pricing structures?

- *Utility revenue loss*. Dynamic pricing can lead to net revenue loss for utilities. What can and should be done to minimize such losses and ensure that utilities have incentives to promote efficient solutions?
- *Potential benefits*. Will the new rate structure yield net benefits?
- *Retail competition, default service, and load profiling*. Does the existence of default or standard offer service pose special challenges? What kinds of retail rate designs should be required for default service?
- *Load profiling and settlement*? What changes, if any, can be made to the present system of load profiling and settlement that will allow for more economically efficient pricing in the absence of more sophisticated metering capabilities?

Metering Issues

- *Purpose*. What aims are to be served and what functionalities are needed to serve them?
- *Cost-effectiveness*. How should the potential cost-effectiveness of various approaches to metering and communications be measured? What benefits should be counted? In order to fairly evaluate the cost-effectiveness of deploying advanced metering, policymakers must be clear about the purposes that the metering will serve, in both the near and longer terms.
- *What is the current state of meter and AMR deployment in the region?* How many customers currently have traditional revenue or interval meters, or advanced metering? How should the mix of existing meters and networks affect new technology choices?
- *Should advanced metering be provided competitively? Who should own the meter?*
- *Large-scale or targeted deployment?* Should advanced metering be deployed to all customers or to a subset of them, defined perhaps by connected load (say, greater than 50 kW)? The answer to this will obviously depend on the objectives sought.
- *Smart Meter, Dumb Network or Dumb Meter, Smart Network?* Where should intelligence reside – at the meter or farther up the network? This decision too will be affected by the policy and program objectives, and by issues surrounding the integration of the advanced metering system with other key information systems (the utilities', ISO's, vendors', customers', etc.).
- *Information control, access, and format*. Whether metering services are provided competitively or by distribution utilities (or by a third party), there arise a host of issues surrounding control of and access to customer information. What kinds of customer information should be made available, and to whom?

II. BACKGROUND INTO RETAIL PRICING, METERING, AND SETTLEMENTS[1]

Electric service is priced in a variety of ways. Pricing policy, whether set by firms or regulators, is influenced by a number of factors and objectives. Among these are economic efficiency, fairness, revenue stability, as well as certain practical considerations, such as simplicity, customer acceptance, continuity, and the availability and costs of metering and communications technologies to support those policies. When viewed in this light, pricing structures run along a continuum that marks the trade-offs between innovative and more complex pricing on the one hand and information needs and administrability on the other. The further one deviates from average embedded prices, the more "dynamic" the rate structure becomes.[2] That continuum can be roughly divided into three broad segments:

- *Energy-only pricing.* Rate designs that do not require special metering capability beyond that of the traditional revenue meter, which measures energy consumption only and is typically read once a month: flat, seasonal, block, etc.;
- *Multi-part and time-of-use pricing*. Rate designs that depend upon more sophisticated metering – multi-part (energy and demand) and time of use – but are still mostly read only monthly; and
- *Real-time pricing*. Rate designs that send customers different prices on short notice for different hours of the day and for different days, to in some way reflect changing conditions in the short-term market – *e.g.*, real-time pricing (RTP) – and make use of sophisticated metering and communications systems that link them to any of several entities (the load serving entity, utility, or system operator).

In a vertically integrated market, all services and rate options are provided by the monopoly utility. Restructuring, however, adds layers of complexity: Who owns the metering and communications systems? How will they be paid for? What is the role of the distribution company in the long run? What effect does the availability of default

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[1] This section relies heavily on the following sources: Levy Associates, *Advanced Metering Scoping Study*, California Energy Commission, August 9, 2001; New York Public Service Commission, *Information Flow/Technology*, Competitive Metering Working Group 3, August 11, 1998; NYPS, *Regulations*, Competitive Metering Working Group 4, October 1, 1998; Plexus Research, Inc., *Data Access Metering & Data Communication Requirements*, National Association of Regulatory Utility Commissioners, March 31, 1998; King, Chris S., *The Economics of Real-Time and Time-of-Use Pricing For Residential Customers*, American Energy Institute, June 2001; King, Chris, "How Competitive Metering Has Failed," Public Utilities Fortnightly, November 15, 2001; and Cambridge Energy Research Associates, *Capturing Value: The Future of Advanced Metering and Energy Information*, 1999.

[2] "Dynamic pricing" is a term used to describe any rate design that aims to give customers a truer signal of the economic costs of meeting their demand than simple average cost rates. Thus, a shift from average rates to time-of-use rates to demand and energy charges or to the various forms of real-time prices is considered a move toward more dynamic pricing. Others hold a more narrow definition: dynamic pricing "is any electricity tariff that recognizes the inherent uncertainty of supply prices." Stephen S. George and Ahmad Faruqui, Charles River Associates, *The Economic Value of Dynamic Pricing for Small Consumers*, presentation at the California Energy Commission Workshop on "Achieving Greater Demand Response in the California Electricity Market," March 15, 2002.

service have?[3] Even in competitive retail markets, most small commercial and residential customers purchase electricity under default, or standard offer, service. For the most part, this has meant that these customers have continued to receive electricity at fixed two-part (energy and customer) or three-part (demand, energy, and customer) rates. How can the structure of a state's transition to competition and the nature of default service support or impede demand-responsiveness by customers and load-serving entities (LSEs)?

A. Pricing and Metering

1. Energy-Only Rates and Revenue Meters

Metering's primary function has been, and remains, to serve the billing function.[4] In their typical and most rudimentary form they measure kilowatt-hour usage only. They are electromechanical devices; a motor spins in relation to the current and voltage applied, and this spinning actuates the meter's dials. The technology has proven extremely reliable and accurate, and the life of a meter is often longer than 30 years.

These meters are read on a periodic basis, usually monthly. The previous period's reading is subtracted from the current period's to determine a net usage for that period. The information provided by these low-cost "revenue" meters is limited in both scope and temporal usefulness: it reveals nothing about the customer's usage patterns and it is available for review only after manual meter reading, typically long after the fact of consumption.[5] These shortcomings constrain providers to rate structures that are not time-differentiated within billing periods, but they do allow for certain consumption-based structures (*e.g.*, inclining and declining blocks). In addition, seasonal differentiation is possible, so long as the rate changes correspond to the beginnings and ends of billing periods.

Seasonally differentiated rates have the effect of assigning a greater share of the system's costs – costs incurred to meet the peak – to the months of peak usage. They are a simple and effective, if blunt, tool, giving only the most general of signals about the changing costs of production. They have nevertheless been effective at encouraging customers to limit or reduce their usage at high-cost times, for example, encouraging shifts from electric heat to other forms of heating or, in summer-peaking areas, promoting the use of more efficient air conditioning. By assigning costs more accurately to those who cause them the objectives of efficiency and fairness are both served. Inclining block rates, where an initial amount (or "block") of energy usage is priced at one rate and the next

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[3] For simplicity's sake, we use "default service" to describe two categories of service, which in some jurisdictions are treated separately but are in others combined. One is "standard offer service," the electric service provided to those customers in a retail market who do not choose a competitive provider. The second is "default service," the service provided to new customers before they make any choice about service provision. In many respects, these services resemble traditional regulated utility service.

[4] This wasn't always the case. In the early years of the industry – the late 1800s – electric service was sold on the basis of end-use, not usage. Metering was expensive, and so long as there were increasing economies of scale, fixed recurring charges for service were sufficient.

[5] Plexus at 48-49. Historically, these meters have been electromechanical in design, but in recent years the solid-state electronic alternative has proliferated.

amount at a higher rate, and so on, have the effect of discouraging energy waste. There is a significant correlation between the timing of usage in the high-cost blocks and the incidence of high-cost periods on the system as a whole.[6] This correlation is not absolute, however, since a monthly system peak may not occur at the time any one customer is purchasing its usage under the higher tail-block rate. But, to the extent that the threat of the higher rate broadly discourages discretionary usage, which tends to correlate with peaks, a more efficient equilibration of demand and supply is achieved. Declining block rates, often seen in systems characterized by excess capacity, have the opposite effect – namely, they encourage supplemental usage and can mask any relationship between that usage and system peaks.

2. Time-of-Use Rates, Demand Charges, and Associated Metering

Rates that vary by periods that are shorter than the billing period are called time-of-use (TOU) rates. Typically, there are different rating periods within each 24-hour period, thus time-of-day (TOD) rates. TOD rate structures differentiate between daily peak and off-peak times. The simplest type of TOD rate structure requires a meter that can differentiate between consumption in the two (or sometimes more) daily periods. They function, in effect, as multiple revenue meters, tallying energy usage by the hours in which it occurs. The meter is read in the same way as other revenue meters, except that now there is a monthly aggregate for each daily rating period. In certain cases, the simple revenue meter can be modified to support TOU rates by the addition of electronic registers that measure and record usage by rating period. Given the higher costs of metering and administration for TOU rate structures, they have been limited primarily to the higher usage consumers.

Rate structures that impose separate charges for energy (kWhs) and demand (kW) are referred to as multi-part rates.[7] The energy portion of the rate covers the provider's costs of production and the demand portion covers the costs of the capacity to supply that production (generation, transmission, and distribution).[8] These rate designs too require a more complex metering, to record both energy usage and peak customer demand during

[6] Extensive analysis by the Regional Technical Forum of the Northwest Power Planning Council concluded that residential lights and appliances usage has a very high load factor and low coincidence factor, while residential space conditioning has a very low load factor and high coincidence factor. Since space conditioning is a discretionary part of residential usage, while lights and appliance usage is universal among residential consumers, the conclusion is that higher usage is correlated with a significant increase in the cost of providing service. See www.nwppc.org, Regional Technical Forum.

[7] The use of the term "multi-part" is occasionally confusing. Since virtually all rate designs include some kind of fixed, recurring periodic charge (the customer charge, designed generally to cover the costs of metering, billing, and line drops), they are all in this sense "multi-part." Thus, energy-only rates are often called "two-part rates," and demand and energy rates called "three-part." Ignoring the customer charge, these rates become "one-part" and "two-part," respectively. This becomes further confused in discussions about real-time pricing, where "one-part" and "two-part" do not indicate whether demand charges are disaggregated from energy prices, but rather whether the rate has both an embedded (historic cost) component and an hourly (marginal cost or market) component. In this document, the use of the term should be clear from context.

[8] Admittedly an oversimplification. Precisely what's included in energy, demand, and also customer charges varies from jurisdiction to jurisdiction and company to company.

the billing period. In the past, these meters typically did not record the hour in which the peak was hit.

These two-part rates are an improvement over average energy rates, in that they enable a customer to reap the financial benefits of reducing its non-coincident peak demand. However, customer response to the rates may not necessarily improve the actual cost characteristics of its load profile. The value of the customer's response depends in part on the relationship of the customer's peak to the relevant system or subsystem peak. Where the coincidence between the customer's peak demand and the system peak is high, the benefits from a demand response are also high.[9] If a customer chooses not to limit its peak demand, then at least it is paying more, or perhaps even all, of the incremental costs that its demand imposes on the system, an allocative outcome that many regulators have deemed reasonable.[10] But where the customer's peak is not closely correlated to the system peak, then any action that the customer takes to reduce its peak does nothing for the overall system peak (although there may be some distribution benefits), and may even harm it, if the customer actually shifts some of its peak demand to the times of system peak. Multi-part rates have in many cases been time-of-use and/or seasonally differentiated as well. The more closely these types of rate designs isolate customer behavior at the time of the system peak demand, the more accurately they convey meaningful pricing information to consumers.

These more complex rate designs can, of course, be supported by interval metering. Such meters, as their name suggests, record and store usage data for each interval, generally an hour, though often shorter periods are possible (even down to one minute). Most utilities in the United States collect hourly usage data from their larger commercial and industrial customers, although the data are typically retrieved only once a month. The infrequent collection inhibits the utility's ability to offer more dynamic pricing options. But it should be noted that dynamic pricing is not the sole or even primary justification for interval meters. The data provided by interval metering improve settlement accuracy, support the more accurate assignment of costs to customers, give LSEs better tools with which to manage their customers' loads, support rate design generally, and improve load profiling, all of which provide significant value to companies and customers.

In the 1990s, electronic meters, capable of recording and storing huge amounts of information, began to penetrate the market. They are extremely accurate and are easily linked to communications networks, sending data to the utility and often to the customer as well. They tend, however, to be significantly more expensive than electromechanical meters – $100 or more versus $25-$30 installed – not including network costs, if any.

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[9] Borenstein, Severin, *Frequently Asked Questions About Real-Time Pricing for California Summer 2001*, University of California Energy Institute, March 2001, at 2-3.

[10] Where a customer's peak does not coincide with the system peak, the two-part rates still provide a signal of cost causation, if only with respect to the distribution network, which is designed to meet customer non-coincident peak demands.

3. Real-Time Pricing

Real-time pricing (RTP) is the next step in time-sensitive pricing. It is any system that charges different retail electricity prices for different hours of the day and for different days, usually based upon some measure of short-term power costs. RTP does not necessarily mean that the retail price in any given hour would be equal to the wholesale price for that hour (although that of course is one approach), but it is seen as a way to reflect the real and immediate changes in marginal costs of generating and delivering electricity.[11] There are a wide range of RTP programs around the country, and most of them combine wholesale and regulated pricing mechanisms, with trade-offs in risk and price levels. A number of examples of RTP are detailed in the Appendix.

4. Summary

The following table provides a matrix of meters, their system characteristics, and the rate designs they can support.[12]

Rate Designs	Type of Meter System	System Features	Capabilities for Rate Design
• Energy-only • TOU • Demand and energy • Seasonally differentiated	Conventional Manual / Electronic Keypad	• Requires meter reader to cover a fixed route • Meter values key-entered or electronically downloaded via port to hand-held recorder	• Typically limited to a single kWh usage value each billing cycle • TOU meter for TOU rates • Demand meter required for multi-part rates • Cannot economically or logistically support the collection of time varying kW interval data • Data only available once each billing cycle or with special read
• Energy-only • TOU • Demand • Seasonally differentiated	Remote Meter Reading	• Requires meter reader to cover a fixed route • Van-based drive by or hand-held systems that use low power radio to transmit meter reading over short distances	• Can support the collection of multiple kWh register values used in standard TOU rates • Demand meter required for multi-part rates • Communication methods cannot economically or logistically support the collection of time varying kW interval data • Data only available once each billing cycle or with special read
• All of the above • Real-time pricing	Automated Meter Reading	• Meters connected to a data repository by telephone, PCS, paging, satellite, fiber, or other communication technology • Stored meter reading can be collected on a fixed schedule or on demand	• Preferred methodology for collecting interval data • Full complement of interval and other meter data generally available on demand • Accessibility varies by technology

[11] *Id*. at 1; Levy Associates at 9.
[12] Levy Associates at 10.

B. Advanced Metering and Communications Systems

By far the vast majority of meters throughout the country (well over 95% of the 110 million meters deployed) are simple revenue meters that must be read manually. Their inability to be remotely accessed more frequently than once a month renders them incapable of supporting the more innovative rate designs and demand-response programs.

In contrast, advanced metering and communications are those technologies that can, to varying degrees, record, process, and transmit time-specific information about a customer's electricity usage.[13] Interval metering, recording at least hourly usage data, is the basic and most common form of advanced metering. It can be accomplished through the use of greater electronic functionality resident in the meter, through frequent polling of meters using automated meter reading (AMR) systems and data processing capabilities higher in the communications network, or through varying combinations of the two (including, for instance, two-way transmission of information for certain real-time pricing programs).[14] Advanced metering and communications can also provide a wide range of other information services – for the customer, the LSE, the distribution company, and the system operator. Although they are not all directly related to short-term demand-response, they all can have an impact on customer behavior. Among the many activities that advanced metering can support are following:

- Pricing and Billing
    - Rate design
        - Dynamic pricing
    - Billing and collection
- Customer Service
    - Billing inquiries, delinquencies, etc.
    - Mass marketing
    - Outage and emergency reporting
        - Emergency alerts (flooding, medical, high and low temperatures, forced entry, etc.)

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[13] In most discussions of advanced metering, the term is used to refer to both the metering and communications system, which, combined, provide the functionalities necessary to support sophisticated dynamic pricing. In this section, we differentiate between metering and communications for clarity only.

[14] Automated meter reading refers to the variety of ways in which data are communicated remotely from the meter to the utility or (in an unbundled metering services environment) the meter reading or meter data management provider. AMR may be used simply to transmit usage data from the meter or to implement advanced functionality such as outage detection, remote programming of meters by an authorized party, or other functionality. New York Public Service Commission, *Information Flow/Technology*, Competitive Metering Working Group 3, August 11, 1998, at 40. Its capabilities will depend in part on the method of communications. In its simplest forms, AMR enables a meter reader to download data from the meter to a hand-held electronic recording device by using an optical port, short-distance radio signal or cellular technology (such systems often allow the reader to remain in the vehicle and collect data while driving by the customer's premises). A subset of AMR is network meter reading, which, as its name implies, depends upon a fixed network for meter reading and can effectively eliminate the need for customer visits to take measurements (a significant cost savings). The existence of the network makes various forms of dynamic pricing possible, such as RTP, which requires some form of two-way communications. It also gives utilities (or LSEs) more options for the meters themselves, by using the network to provide functionalities that would otherwise be resident in the meter.

    - Service calls
    - Evaluating characteristics of customer usage
        - Reactive power, power quality, per phase information, diagnostics
- Energy Services
    - Provided by utilities, LSEs, energy service companies (ESCOs)
    - Customer load management
- Meter maintenance
- System Operations
    - Dispatch
        - Demand response programs
        - Verification of load reductions
    - Technical loss identification
    - Non-technical loss (diversion) identification
    - Settlements
        - Load profiling (where still needed)
    - Load forecasting
    - Load research
- Planning (distributed utility, transmission, or integrated resource)
- Information for developing improved building and appliance standards

1. Meters and Networks

What kinds of metering and communications systems will support demand-response depends on several interrelated factors, among them the information needs of the demand-response programs, retail rate structures, the timing of information retrieval, communications requirements, and the relative costs and benefits of the various alternatives. The uses to which usage data are to be put will determine in part what functionalities are needed. Considerations include the following:

- *Usage Measured.* Will the meter measure only energy usage or instantaneous demand as well? The answer to this is, in part, a function of the amount of time between measurements.
- *Interval length.* For what periods of time is information needed? Interval meters today can record energy use data in increments as short as one minute. The uses to which the data will be put will determine the frequency and types of information that a meter should provide, but at a minimum hourly data are required for both load profile analysis and billing. Shorter interval data will allow energy managers and LSEs to more accurately measure demand and link it to specific end-uses.
- *Data storage capacity.* How much data should the meter be able to store? The answer is a function of both the frequency of retrieval and the value of lost information. Typically, metering equipment for large industrial and commercial customers is capable of storing at least one month's worth of 15-minute interval data, even though the data are collected on a daily or even hourly basis. This provides a significant measure of security against loss.

- *Remote communications options.* Meter owners, providers of metering and data management services[15], and end users are often able to access meters remotely for billing, reprogramming, and other purposes. This saves significant time and expense.[16] More important for demand response is the *frequency* of data retrieval, which will determine in part to what uses they can be put.
- *Meter Architecture.* Meter buyers need to consider whether modular meter architecture and software-enabled upgrades will be valuable. Many meter manufacturers offer enhancements through hardware option boards or software that can be purchased and enabled later, which saves buyers from paying up front for features they may not use right away.

The requisite capabilities of the meter are a function of the communications network (or lack thereof) to which it is connected. There are two broad approaches to the problem: “dumb meter, smart network” and “smart meter, dumb network.” They differ chiefly in where in the system the higher-level information processing occurs. They also differ in the degree to which the network upon which they rely is dedicated, or “private.”[17]

a) Dumb Meter, Smart Network

The “dumb” meter has little in the way of intelligence. It merely records energy usage. The information is made meaningful by the ways in which the “intelligent” network collects, manipulates, and “time-tags” it. A variety of networks are used – radio, paging, telephone, cellular, cable, etc. – often in conjunction with each other, but at least one element of the combined network is dedicated[18] Generally, that part of the network that links the meter to at least the first level of data aggregation and processing is dedicated as is, for example, Schlumberger’s Cellnet system.

The advantages of the “dumb meter, smart network” system lie in the lower costs of meters, meter upgrades, and information management (few processors). There is a trade-off between the costs of the meters and the costs of the dedicated network such that this approach is typically the lowest-cost method of performing AMR in high customer density areas. An obvious disadvantage of the system is its vulnerability to significant

[15] Meter data service providers, who collect, translate, and analyze meter data for billing and related purposes, are distinguishable from meter service providers who physically handle meters for purposes such as installation, maintenance, setting and upgrading internal parameters and removal. Of course, a firm may offer both services. New York Public Service Commission, *Meter Ownership and Control*, Version 3.1, Competitive Metering Working Group 1, July 17, 1998.
[16] The literature generally differentiates between remote meter reading and AMR. Remote meter reading requires a meter reader to visit or pass near a customer site, but enables the reader to collect data using a low-powered radio over short distances. These are typically hand-held or drive-by systems. AMR, in contrast, is any of a variety of systems that transmit data from the meter to the utility, LSE, or meter reading or data management firm. AMR may be used to transmit simple energy usage data from the meter, or to transmit more complex measures of usage recorded in the meter, or to provide other functionalities. Levy Associates at 9-10.
[17] Plexus at 58-60; NYPSC Working Group 4 at 20*ff*.
[18] Itron webpage, www.itron.com.

data loss if communications are disrupted.[19] Frequent interim polling of the meters can provide significant protection against this.[20]

Whether a "smart network" can be developed will depend in part on whether existing meters can be adapted to the uses desired. Upgrading the typical energy-only revenue meter typically involves installation of meter-reading device that can be polled remotely at desired intervals (every 15, 30, or 60 minutes, as appropriate, for load research or settlement, or twice daily for simple TOU revenue collection).[21] One option is to install modules that can be polled, but then to use those modules for real-time information gathering only during outages (for identification of outage locations) or during critical cost periods (when short-run marginal prices might apply – refer to the discussion of the Gulf Power AEM program in the appendix). This avoids the cost of frequent meter reading and data handling except during periods when it is particularly valuable.

The devices themselves often do not display usage information for the customer, but that information can be made available to the customer later (*e.g.*, the next day) via the internet. The costs of such upgrades can vary widely, depending on the nature of the information provided, the communications network needed to support them, and the number of meters installed (*e.g.*, \$30-\$300 per installation).

b) Smart Meter, Dumb Network

"Smart" meters are capable of providing most, if not all, data storage and management capabilities needed for advanced, time-based rate designs and energy management systems. The quality of the information is not dependent on the timing of its retrieval or on the processing capabilities further up the network. In many cases, the customer can also download the data directly from the meter, and in a format that's immediately readable. Whereas dedicated "smart" networks are cost-effective when deployed in customer-dense areas, the "smart meter, dumb network" system, which relies on public, or "transparent," networks is less costly in low-density areas.[22]

C. Determining Loads and Settling LSE Obligations

Prior to industry restructuring, utility loads in New England were met through the centralized dispatch of their generation entitlements by the New England Power Pool. Because all customers within defined geographic areas were served by single (monopoly) companies, the monthly financial settlements among the companies were based on the

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[19] While the amount of energy consumed might be stored in the meter and later retrieved in the event of a communications failure, the usefulness of the information is greatly reduced if, for example, the ability to disaggregate it for TOU billing purposes was lost because it wasn't collected at the appropriate intervals.
[20] Plexus at 59.
[21] For example, revenue meters can often be modified by the installation of a device (a "pulse-initiator") that provides electronic pulses that correspond to the rotation of the meter disk. These pulses are recorded electronically and can be retrieved at specified intervals. Plexus at 49.
[22] The distinction isn't necessarily a rural-urban one. Where many firms are providing competitive metering services in a given area, customer density for each company may be diluted to the point that a "smart" network is not cost-justified.

aggregate loads of those geographic areas, as metered at the relevant level of the transmission or sub-transmission system. Retail competition has rendered this method of settlement obsolete, since now the customers within each metered area of the network no longer belong to a single company but may instead be served by many. In the absence of hourly load information about every customer with an area, the question of how to determine each load serving entity's responsibility for energy and capacity arose. The solution was load profiling.

1. Load Profiling

Traditionally load profiling was, and still is, used to design retail rates. Customers with similar usage profiles are typically grouped together and charged rates specially designed to cover the costs that their consumption imposes upon the system. In the new retail electric markets, those load profiles have been used to establish the settlement obligations of load-serving entities, where it is no longer possible to assign wholesale costs according to metered (*e.g.*, substation) data.

In the absence of individual customer information that describes the customer's hourly usage, an estimate of the customer's load profile must be made in order to determine the contribution of the customer's demand to the LSE's overall load at different hours of the month. Customers are grouped according to the general characteristics of their usage (for example, low-use residential, high-use residential, small commercial, large industrial, etc.), and a load profile for each customer class is determined (typically through a "load study" using statistical methods). All customers within a class are deemed to have the same load profile; they differ only in the amount of energy they use during a billing period. The distribution company then sums the load profiles of customers served by individual LSEs serving load within the service territory to establish each LSE's overall load profile. Every month, the system operator uses each LSE's composite load profile as reported by the distribution companies to allocate the total amount of energy purchased by the LSE (adjusted for losses and "unaccounted for" energy) across the period's hours in order to establish the LSE's responsibility, hour by hour, for the system dispatch.

This process is called "settlement." It establishes what LSEs must pay to wholesale providers, reconciling the costs and volumes of contractual obligations with actual deliveries and allocating unaccounted for energy among the market participants.

Since the load profiles determine what an LSE pays for power, what an individual customer's demand actually looks like is not directly relevant to the settlement process (though it is highly relevant to the actual costs that were incurred to balance the system). To the extent that a customer's actual load profile differs from the class average, the LSE sees neither the savings (if, for instance, the customer has less-than-average on-peak demand) nor the costs (if the converse is the case). Without some kind of mechanism in the settlement process that recognizes changes in demand, the LSE or the customer has little incentive to go after cost-effective savings through demand-response programs, end-use efficiency, or innovative rate structures.[23]

In New England, LSEs are responsible for determining the load profiles of their customers and for providing them to the ISO as part of the settlement process. Originally with restructuring, the load profiles developed by the utilities for rate design purposes were used. There are several approaches to determining load profiles – static, dynamic, and deemed – and variations within each. The differences among the methods derive primarily from the proximity in time of the historic data upon which they are based to the consumption to which they will be applied. Static profiles are typically based on a customer class's usage pattern on a similar day (or week or month) in a previous period (year). Their accuracy depends on the statistical validity of the load research sample group. The various dynamic load-profiling methods require that load research sample data be collected continuously and used to regularly adjust the customer class load profiles. In some cases this calls for daily updates of information, thus accounting for the effects of weather and other changes in end-use. Deemed load profiles are similar to static profiles, but are based on engineering data rather than direct measurement. Street-lighting load is an example of deemed profiling.[24]

2. Settlement of Interval-Metered Load

The actual hourly loads of customers who have interval meters can be assigned to their LSE. They are combined with profiled load to determine each LSE's total obligation (adjusted for unaccounted-for-energy, which results from errors in load profiles, errors in calculating system losses, errors in customer-specific data, errors in metering, unmetered utility uses, and theft).[25]

The installation of a significant number of interval meters on a system can significantly improve the quality of data used for load profiling. Typical load research programs use samples of a few hundred customers, and achieve accuracy in the range of +/- 5%. With improved and lower cost metering, it may be economic to narrow that range of

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[23] Plexus at 14-18, 39-40. Thus, blunt load profiling policies inhibit demand response, load management, and efficiency programs that would lower load and prices at high-cost periods. See Richard Cowart, *Efficient Reliability: The Critical Role of Demand-Side Resources in Power Systems and Markets*, NARUC, June 2001, at 40-41.

[24] *Id.* at 33-35; New York Public Service Commission, *Load Profiling*, Competitive Metering Working Group 5, August 14, 1998, at 21-28; communication from Lucy Johnston, Synapse Energy, March 21, 2002; and Maine Rules, Chapter 321, Load Obligation and Settlement Calculations for Competitive Providers of Electricity. In 1998, New York concluded that load profiling was adequate for settlement purposes during the transition to retail competition. Through a working group process, the state studied the various means of determining customer load profiles and the costs of incremental improvements in methods. They are, from the least to the most accurate: static load profiles, dynamic modeling load profiles, dynamic load profiling, interval metering. (The New York Working Group differentiated between dynamic load profiling, which calls for daily updates of profiles, and dynamic modeling load profiling, which calls for less frequently updated load profiles.) The state concluded that the total costs of load profiling were such that, if assigned only to the retail choice customers, the total cost of competitive service would become so high as to effectively bar competitive retail providers from operating in the market. They were not, however, considering this question in the context of demand-response.

[25] Plexus at 17-18.

uncertainty, improving settlement without requiring advanced metering for all customers. An interesting policy question is whether individual customers with interval meters installed for the purposes of load research and profiling should be treated differently, in settlement, than the class of customers for whom their interval data is applied for settlement.

III. PRICING EXPERIENCE IN NEW ENGLAND AND ELSEWHERE

A. Pricing and Program Options to Elicit Customer Demand Response

There are a variety of approaches to retail pricing that will evoke changes in customer behavior. Whether the changes can be relied upon for managing system loads in the short run depends on the degree to which the rates reflect the real-time variability of wholesale prices. While time-of-use and seasonally differentiated rates will have positive long-term impacts on system load factor, resource needs, and efficiency, they provide little incentive to adjust load in response to actual hourly or daily prices. The challenge facing policymakers is to develop rate structures that meet a variety of objectives – among them economic efficiency (in both the short and long runs), fairness, administrability, simplicity, and so on.[26] Leaving questions of retail competition and default service to the next section, what follows here is simply a menu of pricing and program options to create greater demand response, which policymakers can consider. The appendix gives detailed descriptions of experience with the various rate designs and programs, both in New England and across North America.

Time-of-use rates. These daily energy or energy and demand rates are differentiated by peak and off-peak (and, possibly, shoulder) periods. One variation is the overlay of a real-time "critical" peak period, in the manner of the Gulf Power AEM program. Another is to identify critical days, rather than simply hours, during which consumption is priced to reflect the very high market costs.[27]

Seasonally differentiated. Those months during which consumption drives system peak see rates that reflect, in some measure, the costs of the capacity (generation, transmission, and distribution) needed to serve that peak. Seasonal differentiation can be applied not only to simple energy-only rates, but also to TOU and multi-part rates.

Multi-part rates. These rates separate the charges customers pay for energy and capacity. Historically, demand charges were linked not to coincident system peak but simply to the customer's peak demand during the billing period.

Block rates. These are typically energy-only rate designs in which the unit price for incremental consumption changes as defined thresholds of usage within a period are passed. For example, the first 200 kilowatt-hours of usage might be priced at $0.10/kWh, the next 400 kWh at $0.08/kWh, and all succeeding usage at $0.065/kWh. This would be an example of declining block rates, but they could as easily be inclining. While these rate do give customers some idea of the cost of incremental production, it is rough at best, since there is an imperfect relationship between the rate charged and the time of use (coincidence with system peak or other constraint).

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[26] Bonbright, James C., *Principles of Public Utility Rates*, Public Utilities Reports, Inc., Columbia University Press, New York, 1961, at 291.

[27] George and Faruqui.

Distribution-only service. In restructured industries where commodity sales are separated from delivery service, the design of rates for distribution remains a regulatory responsibility. Treating distribution as if its costs do not vary with the time or amount of usage (which, in the long run, they do) can lead to the adoption of large fixed, recurring rates that are unavoidable, regardless of changes in demand.[28] This can inhibit customer willingness to take otherwise cost-effective demand reduction actions.[29]

Real-time pricing. RTP links hourly prices to hourly changes in the day-of (real-time) or day-ahead cost of power. One option is “one-part” pricing, in which all usage is priced at the hourly, or spot, price, adjusted as appropriate for delivery, congestion, line losses, and other relevant costs. Unlimited in this fashion, they place all price risk on the customer and, consequently, few customers have taken service under them. Providers have developed risk mitigation (risk sharing) products to address this concern: for example, price caps and floors, options for locked prices for limited periods, and triggers (where the spot price is paid only when it exceeds a specified minimum for a specified period). A second approach is “two-part” pricing. There is an “access” charge for using a pre-determined baseline quantity (*e.g.*, baseline kWhs * embedded rate/kWh), and spot prices (or credits) for variations from the baseline. The baseline is often set on a customer-specific basis. The two-part RTP rate is a more common form of price-risk sharing, and it provides a certain measure of revenue certainty for both the provider and the customer.

Interruptible. Programs (in the form of tariffs or customer agreements) that give utilities or LSEs a right to interrupt service at times of peak or system stress are a powerful load management tool. They come in a variety of forms – for example, discounted or marginal energy rates, reduced or eliminated demand charges, bill credits, etc. – to reward the customer for a reduced or capped contribution to peak capacity needs. On the flip side, there are often penalties for failure to interrupt. They are an overlay on any of the other rate designs.

The following table summarizes the various rate designs and load management programs of a number of utilities in North America. The rates and programs are described in greater detail in the appendix.

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[28] In 2002, the Nevada Public Utilities Commission approved significant increases in the monthly recurring customer charges of Nevada Power and Sierra Power (a more than threefold increase). Whereas the majority of distribution costs had previously been recovered in unit energy and demand charges, the new fixed rates fully cover those costs.

[29] Weston, Frederick, *Charging for Distribution Utility Services: Issues in Rate Design*, National Association of Regulatory Utility Commissioners, December 2000.

Company and Program	Seasonal	TOU	Block	Multi-Part	RTP One-Part	RTP Two-Part	Interruptible	Distribution Only
CVPS	√	√		√			√	
Maine Standard Offer	√	√		√				
Maine T&D	√	√		√				√
Puget		√						
California			√					
GPC						√		
Duke						√		
TVA					√		√	
PG&E					√			
SCE					√			
BC Hydro						√		
CEC proposal						√		
Puget RTP		√			√			
NW Drought							√	
Gulf Power		√			√			

1. Lessons Learned

Seasonal, time-of-use, block, and multi-part rate designs have had significant and long-term impacts on the electricity usage in New England and elsewhere. For example, in Vermont, such rate designs contributed to changes in end-use penetration (a substantial reduction in electric space and water heating) and in building stock (improved R-values). The rates designs do not, by themselves, promote short-term "dispatchability" of load – that is, interruptibility – but they have led to higher system load factors, smaller needle peaks, and the price stability and cost savings that flow from them. In this way, the effect of more economically efficient rate designs on customer class load profiles is similar to that of improved end-use efficiency.

The restructuring of New England's wholesale market has forced states to reassess their traditional rate designs. No longer does a utility's or LSE's peak necessarily determine its high-cost periods; instead, providers' costs are driven by the overall market. In northern New England, this means that winter is not the high-cost season, but summer is. Regulators have begun to reevaluate the rate designs for regulated services – default and T&D.

Of **real-time pricing and load reduction programs**, the following observations can be made:[30]

- Real-time pricing and load management incentives can produce significant load shifting benefits, and most of the short-term load response comes from a relatively small number of customers (GPC, Bonneville, California).
- Certain types of customers are more likely to shift load than others, particularly those with on-site generation, those who have high energy costs as a percentage of total costs, those with non-continuous production processes, and those who have

[30] Faruqui *et al.* at 18-23.

had previous experience with interruptible rates. However, several utilities found that there are occasionally innovative customers willing to load-shift even among those thought less likely to be price-responsive (*e.g.*, a hospital that could modify its chiller use, ski area snow-making, etc.).

- Customers join RTP programs to save money (when the program is voluntary). Customer satisfaction with the program declines as RTP prices increase, particularly among those who do not shift load (GPC, BC Hydro).
- Customers dislike significant price volatility. Several responses to this were created. In the case of one-part rates, several utilities instituted price caps (SCE). In other programs, limits on the number of high- and low-cost days were put on (Virginia Electric Power). And then there was the development of the two-part rate, which not only limits the customer's price risk, but also limits the risk of revenue loss to the utility (GPC, Duke, BC Hydro, CVPS).
- The success of two-part RTP programs depends in some measure on the simplicity of the customer baseline calculation (GPC, Duke).
- It is possible to include an interruptibility requirement in an RTP program (TVA, CVPS).
- Customer education is another critical determinant of a program's success (GPC).

B. Barriers to Innovative Pricing

There are a number of obstacles to the implementation and success of alternative, time-based approaches to pricing. They affect not only customer behavior, but also that of utilities and policymakers. Key barriers include the following:[31]

<u>Cost barriers</u>

- *Capital, telemetry, and administrative costs*. The capital costs of advanced metering, regardless of which entity – distribution company, LSE, or competitive meter provider – can inhibit investment, particularly in an uncertain regulatory environment. Telemetry and other ongoing costs might not be high (*e.g.*, Puget estimates around $1 per month per customer), but added to capital cost, raise the threshold savings rate needed to make an advanced metering program cost-effective.
- *Cost-effectiveness*. Perceptions about the cost-effectiveness of advanced metering, particularly for lower-volume customers, can discourage large-scale investment.

<u>Customer barriers</u>

- *Customer risk aversion*. Price volatility is seen by many customers as an undesirable risk and, thus, as an overall increase in one's electricity costs. Often, customers are willing to pay a premium to avoid time-varying costs (ironically, while utilities incur a cost-premium to provide advanced metering service).
- *Elasticity of loads*. What loads can customers easily shift in time, from hour to hour, day to day, or across even longer spans?

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[31] Faruqui *et al.* at 17-23. Refer also to the discussion of barriers in Goldman at 22-24.

<u>Utility and LSE barriers</u>

- *Utility revenue loss*. This is especially problematic with voluntary programs, which result in customer self-selection: only those whose load profiles are better than the class average will go on the TOU or RTP program. This reduces their total costs, but makes both the utility and (after a rate re-design) its remaining customers worse off (since the diversity benefits of those "good" customers have been lost to the customer class). Also, absent any new price-responsive behavior on the part of these "free-riders," there would be no peak load reduction benefits.
- *Load profiling*. It is in the interest of an LSE whose non-interval-metered customers' loads are better than the average (*i.e.,* higher load factors or lower demands at high-cost time) to support improved methods of load profiling. LSEs whose customers' loads are worse than the average have the opposite incentive, since some part of the higher costs their customers cause is being paid by others.
- *Calculation of the customer baseline for RTP*. While there is no empirical evidence to suggest that customers somehow "game" the determination of the baseline, avoiding this possibility remains a challenge for LSE and utility administrators of RTP and interruption programs.
- *Billing and collection*. Is the utility's billing and collection system capable of settling the accounts with more complicated pricing structures?

<u>Regulatory and Legislative</u>

- *Policymakers' perceptions*. Concerns (not necessarily justified) that, for the most part, customers cannot adjust their usage as price changes have led to regulatory preference for voluntary, rather than mandatory, programs.
- *Fairness*. Not all customers will benefit equally from the new rates. This will depend on how prices actually change and on the degree of customer-responsiveness. To the extent that, in an environment of average embedded cost pricing, demand on-peak is subsidized by off-peak consumption, one can argue that a pricing scheme that more fully allocates costs to those who cause them is inherently more fair.[32] On the other hand, electricity is an essential service in modern society, and public decision-makers will also consider universal service goals in making rate design decisions.
- *Other pricing policies*. The effect of rate caps imposed by the ISO or state or federal regulators. To what extent do such caps inhibit price responsiveness?
- *Lack of coordination with DSM programs*. If utilities provide DSM incentive mechanisms for customers to install storage heating and cooling systems, load controls, and other measures that enable them to shift load while mitigating adverse impacts on the quality of energy end-use, resistance to load-shifting programs may be mitigated.

<u>Technological</u>

- Lack of interval metering.
- Lack of requisite communications equipment.

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[32] Vermont Public Service Board, Docket 5426, Order of July 22, 1992, at 19-20, 23.

- Lack of customer energy management systems, such as load controls, energy storage, and distributed energy systems, which give customers added flexibility in their usage.

Lastly, the existence of default and standard offer service in a competitive retail market can add complications. The legitimate desire of policymakers to protect the lower-usage customers from the volatility of the wholesale market has resulted in rate designs and up-front rate reductions that can inhibit customer demand response. Typically, standard offer service has been provided at average, non-time-dependent rates, often at a discount to pre-restructuring rates. Since, under such circumstances, all of the price volatility risk is borne by the default provider (during the period rates are in effect), one might argue that a risk *premium* rather than a discount is warranted.[33] In any event, standard offer service customers are insulated from the variability of short-term market fluctuations and consequently have no incentive to adjust their loads in response to price. In addition, to the extent (as in Massachusetts) default and standard offer service are provided by multiple suppliers but are settled under the same load profiles, the incentive to take actions to improve customers' load is further muted. Insofar as the average load profile is modified to reflect any improvement, the benefits are shared among all standard offer service providers, not just the one taking action.

[33] Faruqui *et al.*, at 7.

IV. SUPPORTING RETAIL DEMAND RESPONSE: CONSIDERATIONS AND OPTIONS

A. Principles and Issues

What follows is a list of principles and related issues that policymakers can consider when designing and implementing retail rates, programs, and metering systems in support of demand-response:

- *Improved economic efficiency.* Markets and rules should produce least-cost outcomes. Economic efficiency is improved when prices more closely approximate marginal cost. What is the relationship between long-run end-use efficiency and short-run demand response? Does investment in one discourage more cost-effective investment in the other?
- *Overcoming barriers to efficient choices*.
- *Simplicity*.
- *Roles of the ISO, utilities, load-serving entities, and customers*. To whom is the price signal most efficiently sent, the LSE or the end-user? Who has the comparative advantage in bearing the risks? Where should the policy effort be focused, and what can be done to assist LSEs and customers to extract the highest potential value from demand-response?
- *Integration* of retail pricing with ISO load response (*e.g.*, interruptible) programs and needs. Experience suggests that rate designs that signal the economic costs of producing and delivering energy to customers are not enough, in all circumstances, to elicit all cost-effective demand-response potentially available? Do remaining barriers justify the payment of additional incentives?
- *Improved system dispatch*.
- *Environmental impacts*. Should the environmental benefits of avoided emissions and construction be recognized in planning and program design? If so, how?
- *Cost-effectiveness*. This pertains not only to the cost-effectiveness of the rate design itself, but also of the metering system necessary to support it.

B. Pricing and Program Options: Policy Considerations

Section III.A. summarizes the various retail rate design options that policymakers may consider as part of a broader demand-response initiative. This section looks at some of the policy issues that the adoption of these options raises. Although we recognizing that each option requires particular data recording and management capabilities, we assume for now that the state of metering and communications in a territory does not constitute a potential constraint for implementation. Policy questions associated with technology deployment are taken up in the following sections.

The central question for policymakers is what rate structures should be put in place that will promote the most efficient consumption of electricity, given other policy objectives (fairness, simplicity, environmental sustainability, etc.). Answering it is further complicated by the existence of retail competition and default service in states whose industry has been restructured.

The continuum of rate design options sketched out at the beginning of this paper runs from those that send consumers only the barest of economic cost signals to those that reveal almost fully the time-dependent costs of production and delivery. Experience with them shows that, as one moves along the continuum, customers find more ways to respond to the signals: in short, customers' willingness to purchase – their demand elasticity – is revealed. But with any rate design change there will be winners and losers, even if the overall result is to the good, and so the challenge will be to capture the benefits of more economically efficient pricing while ensuring that less elastic customers are treated fairly.

Although one might argue that simply placing all customers on real-time prices would take care of the economic efficiency problem (*i.e.*, all cost-effective demand response would naturally occur), it is not, even if true, a practical solution. For policymakers, the changes in rate design will not be taken in giant leaps, but in shorter, less disruptive steps along the continuum – for instance, a shift from year-round average cost rates to seasonally differentiated or TOU rates. In this context, some of the considerations for policymakers include the following.[34]

Purpose. What objectives are new retail rate designs and programs intended to serve? Some program designs might lower peak demand without lowering overall consumption; others might encourage customers to invest in long-term efficiency measures. Some rate designs may stimulate entry of competitive LSEs into the market, while others would reinforce the role of incumbents and default providers. Some programs may better serve environmental and system reliability goals than others. There are many variations on these questions.

Mandatory or voluntary? Should a new rate design be mandatory? Customers' acceptance of a new rate is largely a function of their ability to adapt to and benefit from it. At first, this may be more a question of perception than reality. In Vermont, for example, the imposition of seasonally differentiated rates was vigorously opposed, though invariably it led to lower utility costs and customer bills in the long run. This was true too of daily TOU rates for high-volume (typically electric heat) customers. Mandatory seasonal or time-of-use rates for lower-volume customers and RTP for large-volume customers could achieve significant savings, but could also impose significant costs upon inelastic users.[35] This could be addressed through the use of a risk-sharing mechanism (as did Georgia Power) or through the targeted marketing of a voluntary program.

Low-volume versus high-volume customers. Price elasticity can vary with total amount of usage in a period. Since for most customers there is a minimum amount of usage that

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[34] Of course, this is a subject to which thousands of pages have already been devoted (by James Bonbright, Alfred Kahn, and others). Here we just want to touch on several issues of particular relevance.
[35] See also Goldman at 30.

is unavoidable (*e.g*., lighting, HVAC, computing, refrigeration), there is less discretionary demand among low-volume users that can be manipulated through pricing or demand-response programs. Would it be appropriate, for instance, to set minimum usage thresholds (either in kWs or kWhs) for the more dynamic pricing structures?[36]

Utility revenue loss. As described earlier, voluntary tariffs for dynamic pricing can lead to short-term net revenue loss for utilities, even if they lead to lower system costs over time. The magnitude of such losses, if any, will depend on a variety of factors including the number of participants, size of the reductions, the ability of the company to offset the losses through other sales (off-peak or off-system), and so on. There can also be net revenue losses generated by mandatory programs. Even though the problem of self-selection is overcome, there still remains the question of whether the company, after customers respond to the dynamic prices, still carries entitlements to generation for which revenue has not been received. What can and should be done to account for such losses and provide incentives to LSEs and wires companies to lower the total power costs faced by their customers?

Potential benefits. Will the new rate structure yield net benefits? (The question of cost-effectiveness in relation to the costs of advanced metering will be taken up below.)

Retail competition, default service, and load profiling. The degree to which the above considerations will affect policy decisions is itself affected by the existence of a competitive retail market. Does the existence of default service pose special challenges? As a general matter, regulators cannot impose particular rate structures upon competitive offerings, so the prevalence of dynamically priced commodity electricity will depend upon market conditions. It will also depend on the availability of the advanced metering needed to support it. In contrast, default service remains effectively a monopoly service. As Maine has done, regulators can approach it as they do vertically integrated service and implement rate designs and other programmatic requirements aimed at eliciting customer demand response.[37] Where there is no interval metering, however, the challenges posed by load profiles remain.

Load profiling and settlement. What changes, if any, can be made to the present system of load profiling and settlement that will allow for more economically efficient pricing in the absence of more sophisticated metering capabilities?

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[36] A simple comparison of the advanced metering costs of the Puget TOU program to its savings shows that the residential component of the program has so far been a net loser. The difference between the on-peak and off-peak wholesale costs, when multiplied by the average savings per residence, was not sufficient to cover the costs of the metering and communications. The utility revenue impacts of this were further exacerbated by the fact that the differential between the on- and off-peak rates at retail was greater than it was at wholesale (thus, the revenue loss to the utility from load shifting was greater than the utility's short-term savings in the wholesale market).

[37] Where default service providers are chosen through a competitive bidding process, the request for bids will have to state the requirements for retail rate structures and demand response programs that winning bidders will have to satisfy.

C. Policies and Technologies to Support Retail Demand Response and Innovative Rate Designs

1. Settling Load Response for Non-Interval Metered Customers

In places such as Vermont where there are still vertically integrated monopolies, changes in customer usage within each metered area of the network (*e.g.*, at the sub-station level) can be measured and settled for each hour. The benefits of any action that the monopoly takes to reduce loads will flow directly to the utility through the settlements process. Those benefits may be shared with the customers whose responses created them (through payments for reductions, discounted rates, etc.) or among all customers in the responsive class or classes (through changes in their rates or rate design).

Where there is retail competition, however, the benefits from demand response can only be directly credited to LSEs or their customers if their customers are on interval meters or if there exists some other, reliable method for demonstrating which customers reduced demand, when they did so, and by how much. A first step is to increase and refine the categories of load-profiled customers. This will require more data on customer behavior, end-uses, weather, etc. Once the new load profiles are available, LSEs or, more usually, distribution companies will be required to assign customers to their appropriate classes.[38]

While this is an improvement that would lead eventually to improved rate structures and customer usage, it is nonetheless relatively static and provides no real way to capture demand response in the short term. Dynamic load profiling methods, which rely on statistically reliable interval metering data, offer yet more improvement, especially if daily updates of profiles are made.

Load studies, which provided the empirical underpinnings for monopoly rate designs, historically were undertaken by utilities, on their own initiative or at the direction of regulators. Restructuring hasn't changed the need for load information – perhaps has given it even greater importance – but now the questions facing regulators are who will gather the information, how will it be gathered, who will pay for it, and how will it be used? Are LSEs acquiring these data? If not, can and should regulators require LSEs to perform this work?[39] What information is proprietary? And so on.

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[38] The question arises as to whether an LSE has an incentive to wrongly assign its high-cost customers to low-cost load profiles and thus foist some portion of the high costs onto all LSEs (through the settlement of unserved energy). If the LSE is charging rates that properly reflect the high cost to serve, then this incentive is muted somewhat. One presumes that the distribution company that reports load profiles on behalf of LSEs has no incentive to do so improperly.

[39] It is worth examining the incentives of LSEs serving low-volume and default customers. Even if an LSE has hedged its price volatility risk (for example, through long-term, fixed price contracts or contracts for differences), it should still have an interest in improved load profiling. To begin, a greater understanding of its customers' behavior will enhance its ability to negotiate with generators. But equally importantly, capturing demand-response and selling freed-up entitlements into the market should be profit motive enough to support actions that will improve the quality of customer usage information.

a) Aggregating Load Response Among Small Customers

In 2002, the New York Price Responsive Load Working Group approved an innovative proposal for aggregating and crediting retail load response among small customers, for use in the state's Emergency and Day-Ahead Demand Response Programs. The New York ISO will allow up to 25 MW of aggregated load response from smaller, non-interval metered customers to participate in the programs. The amount of the curtailments will be determined by alternative approaches to the ISO's basic metering and measurement requirements. Such approaches, typically relying on statistical methods, will be proposed by the aggregators and approved by the ISO. Distributed and self-generation resources and direct-serve customers are not eligible to provide load reductions under alternative performance measures.

The aggregations must be at least 0.5 MW for the emergency program and 0.75 MW for the day ahead. For settlement purposes, the load reductions will be treated as if they were interval metered, that is, reductions will be assigned to the hours in which they were expected to occur.[40]

New York's approach in effect avoids the problems of alternative load profiles, although it does depend on statistically reliable data. It offers a promising model for similar programs in New England.

2. Policy Considerations

Advanced metering, which refers to both the meters and the communications network that links them to the utility or LSE, will support the full range of rate designs and demand-response programs outlined in this and the other NEDRI framing papers. The challenges for metering and communications that are posed by demand response (and restructuring generally) are not technological in nature. The technologies to provide the kinds of metering and data retrieval activities discussed here exist and, for the most part, are already in use somewhere. The question, as always, is one of cost.[41] It is also the case, however, that some of the programs can be implemented without advanced metering, albeit with some loss in performance and financial benefit (for LSEs and customers). In evaluating what kinds of technology might be deployed, policymakers, LSEs, system operators, and other interested parties should address a variety of considerations, among them the following.

Purpose. What aims are to be served and what functionalities are needed to serve them? Many retail rate designs do not require interval metering, but those designs are insensitive to changes in the short-term costs of production. Interval data are not, strictly speaking, necessary to the settlement of load management programs (as the new aggregation program in New York demonstrates), but such data will greatly improve the settlement process, as well as load profiling and rate design generally. Real-time pricing, in contrast,

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[40] New York Price Responsive Load Working Group, Business Issues Committee, *Proposal for 25 MW Limited Small Customer Aggregation Program*, December 13, 2001; communication with Larry DeWitt, Pace Energy Program, March 23, 2002.

[41] Plexus at 50.

requires both interval data (to establish hourly usage) and a communications protocol to inform the customer of hourly changes in prices. Here again, the metering data need not be retrieved in real-time, but once the network to the customer is set up, two-way communications are often possible. Frequent data retrieval can have the effect of transforming a simple kWh meter into an interval meter.

Cost-effectiveness. How should the potential cost-effectiveness of various approaches to metering and communications be measured? Cost-effectiveness – or, more accurately, a general *misconception* about cost-effectiveness – is, in the view of one observer, the primary barrier to deployment of advanced metering systems. This derives mainly from the emphasis of traditional analytical methods (which compare a discounted stream of expected benefits to up-front investment costs) on short-term cost minimization. That is, these methods set cost-effectiveness as a measure of the payback against savings derived only from changes in customer behavior, while ignoring the other benefits that advanced metering can provide: system reliability, lower wholesale costs, marketing, dynamic improvements in energy use over the longer term, etc. (described in section II.D, above).[42] In order to fairly evaluate the cost-effectiveness of deploying advanced metering, policymakers must be clear about the purposes that the metering will serve, both in the near and longer terms.

What is the current state of meter and AMR deployment in the region? How many customers currently have interval or advanced metering? How should the mix of existing meters and networks affect new technology choices?

Should advanced metering be provided competitively? Who should own the meter? LSEs in competitive markets depend on the kinds of information that metering provides, and low-cost access to that information is critical. This is true also of utilities in un-restructured states. Metering equipment and system vendors have, since the mid 1990s, begun to move away from the development of more costly, customized systems for individual utilities in favor of more economic, universal products suitable for the international as well as North American markets.[43]

In early restructuring policy discussions, many analysts thought that metering, data management, and billing services could be unbundled and provided competitively. Given the importance of metering to competitive markets, it was expected that LSEs and other entities would find ways to make metering a new source of value and profitability. This has not come to pass. Two factors – metering's economies of scale and suppliers' fears of stranded metering costs (as customers change providers) – appear to account for the failure of a competitive market for metering to emerge.[44] There may be, in addition, substantial legal and liability issues inhibiting competitors.[45]

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[42] Levy Associates at 28-37.
[43] *Id*. at 39.
[44] King, Chris, PUF, at 30-34. Prior to the crisis in California, less than one-tenth of one percent of customers had competitively installed meters. In New York, no competitive providers have been certified, and no meters installed. In Pennsylvania, only 79 meters have been installed by competitive providers since competition began. Participants in historic utility DSM programs will note that the market barriers to

While metering in general might eventually become competitive, in the nearer term it appears that regulatory action to promote advanced metering is warranted, justified by its potential benefits and by the fact that utilities so far have had little cause to invest in it. Policymakers should evaluate approaches – directives, performance-based incentives, etc. – for encouraging the deployment of advanced metering in their states.[46] Potential options include (a) using ratepayer funds to pay for advanced metering, (b) having customers pay the cost of advanced meters at their facilities, and (c) using public benefit funds to facilitate customer's ability to participate in DR programs (e.g., NYSERDA's programs that are designed to increase customer adoption of enabling demand response technologies).[47]

Large-scale or targeted deployment? Should advanced metering be deployed to all customers or to a subset of them, defined perhaps by connected load (say, greater than 50 kW)?[48] The answer to this will obviously depend on the objectives sought. If the metering is intended to support only limited functions – say, RTP and demand-response among only the larger customers – then the approach will differ from one aimed at providing the wider range of metering functions. The extent of the initial deployment will affect choices in both metering and communications equipment, which in turn can affect the ability of the system to be later expanded. Georgia Power, for instance, has the largest RTP program in the nation, and it has used low-cost technologies – *e.g.*, shared and leased telephone lines, dial-up modems, and standard box recorders – to manage the program. They may not be adequate, however, for large-scale deployment.[49]

Smart Meter, Dumb Network or Dumb Meter, Smart Network? Where should intelligence reside – at the meter or farther up the network? This decision too will be affected by the policy and program objectives. There are significant economies of scale associated with dedicated networks, making them more suited to ubiquitous deployments. There are, in addition, issues surrounding the integration of the advanced metering system with other key information systems (the utilities', ISO's, vendors', customers', etc.). Experience so far shows that no single metering configuration will meet all the needs of a territory in the most cost-effective manner. In large-scale applications, hybrid solutions tend to be the norm.[50] Also to be considered is whether existing meters can be upgraded or must be replaced.

Information control, access, and format. Whether metering services are provided competitively or by distribution utilities (or by a third party), there arises a host of issues surrounding control of and access to customer information. What kinds of information should be made available, and to whom? Where electricity is still provided by monopoly

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deployment of advanced meters (and thus more dynamic pricing) are similar to the market barriers that have always undercut consumer investments in end-use efficiency technologies.

[45] Levy Associates at 39.

[46] King, PUF, at 34.

[47] Goldman at 31.

[48] For example, California set the threshold at 50 kW. Arizona set it at 20 kW or 100,000 kWh/year.

[49] Faruqui at 46.

[50] NYPSC Working Group 4 at 13.

utilities, these issues have been addressed through law and regulatory rules. With the introduction of competitive retail markets, states have begun to examine the questions (*e.g.*, New York, Massachusetts, etc.). As mentioned above, competitive metering has not materialized, and so distribution utilities have continued to provide the service. Protocols for information format, sharing, etc., have been (or should be) developed.

V. APPENDIX: PRICING CASE STUDIES FROM NEW ENGLAND AND ELSEWHERE

A. Time, Demand, and Usage Differentiated Rates in Practice

There is a long and varied experience with TOU rates, seasonally-differentiated rates, block rates, demand charges, and other forms of dynamic pricing across the United States. Some examples are described in the sub-sections that follow.

1. New England

a) Vermont

In the 1974, the Vermont Public Service Board approved a new rate structure for Central Vermont Public Service Corporation. It consisted of time-differentiated (time-of-day and seasonal) and multi-part (energy and demand) rates, for most customer classes. By 1992, all of the state's remaining (at that time, 22) utilities had some kind of time- and demand-based rates in effect.

New England Power Pool (NEPOOL) rules at the time were effective at reducing each New England utility's reserve requirements (by taking advantage of the scope and diversity benefits of the large pool), but the utility was nevertheless responsible for having entitlements to sufficient capacity to meet its likely peak needs. Although NEPOOL as a whole was and is a summer-peaking system, Vermont utilities were winter-peaking, and the capacity costs they incurred were directly related to those winter peaks. Consequently, the retail rate designs implemented during those two decades placed the primary revenue burden on winter use, and did so by pricing incremental winter usage at rates reflecting the long-run marginal costs of production in those periods.

The impact of these rate structures on the state's demand for electricity was substantial. During the 1960s, CVPS's system load factor steadily eroded as demand grew, driven in large measure by ski area growth and the increasing use of electric resistance heating. By the early 1970s, the company's load factor was around 50 percent and heading lower. In 1974, mandatory seasonal rates were put into effect for all customer classes (with a winter-summer ratio of approximately 2:1). In addition, a voluntary time-of-day rate was made available, as well as a voluntary controlled water heating rate.[51] Significant numbers of customers took advantage of the TOD and water heating rates in an effort to reduce their on-peak, more costly consumption. Over the next decade or so, CVPS developed a variety of other rates, including multi-part rates (mandatory for certain high-voltage customers), that provided additional signals about the economic costs of on-peak consumption. By the late 1980s, the company's load factor had improved to well over 60 percent and is currently in the range of 68 percent.[52]

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[51] The controlled water heating rate, using mechanical timers, had been in effect since the 1930s.
[52] Conversation with William Deehan, Vice President, CVPS, March 19, 2002. Also, VPSB Docket 5270, Order of 4/16/90, at 20.

With the restructuring of the New England's wholesale market and the overhaul of the NEPOOL and ISO rules for determining a load-serving entity's capability responsibility, the economic justification for winter peak rates has evaporated (with respect to the system as a whole – but local T&D investment is still driven by local peak demand). Capacity needs are determined on a monthly basis.[53] In the past several years, the PSB has begun redesigning utility rates to reflect this new reality. For the most part, the seasonal differentials have been eliminated.[54]

b) Maine

During the 1980s, largely in response to PURPA, Maine evaluated and implemented a variety of more economically efficient rate designs. For high usage C&I customers, rates were broken down into demand and energy prices, differentiated by both season and time of day. Maine, like Vermont a winter-peaking state, created a four-month winter season (or five-month, depending on the utility). Lower usage C&I customers were put on seasonally differentiated demand and energy prices. High-use residential customers (greater than 2,000 kWh in at least one winter month) were, in the case of two of the state's three utilities, put on mandatory TOD rates. Low usage residential customers saw only seasonally differentiated or inverted block energy prices (the tail-block, for usage greater than 400 kWh/month, was priced 20% higher than the initial block).

These rate structures remained in effect well into the nineties. When the seasonal differentiation in prices was increased in the early part of the decade, there was significant customer dissatisfaction and protest, particularly among those on TOD rates. Ultimately, the PUC approved changes in the rates, the most significant of which was to eliminate the mandatory aspect of the TOU tariff. One utility also eliminated the seasonal differentiation.

Restructuring since then has led to more changes. Customers in the competitive retail market purchase energy according to their needs and the products available. Customers who take standard offer service do so under rate class groupings that bear a general resemblance to pre-restructuring rate designs. Large C&I customers (with demand in excess of 400 or 500 kW) pay two-part (demand and energy) rates that vary both by month and time of day. The rates are specified for each month of the year (in effect, tariffed), following the new capability responsibility rules. Medium C&I customers (50 – 400 kW) see two-part seasonally differentiated rates: summer, winter, and two shoulder periods. The summer period is the highest-priced. Low-use customers, residential and small commercial, pay flat, energy-only rates throughout the year.

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[53] ISO-NE rules require LSEs to have capacity entitlements sufficient to meet their load in each month (*i.e.*, capability responsibility, which includes a margin for reserves). Since Vermont's is a winter-peaking system and New England's a summer-peaking, one would expect (all else being equal) to see relatively lower-cost excess capacity available in the winter.

[54] VT Department of Public Service *Biennial Report, July 1, 1998 – June 30, 2000*, January 2001, at 47. Similar results were achieved in other utilities' service territories. In particular, the rates strongly discouraged electric space and water-heating load, which were highly correlated with peak.

The Maine PUC is currently reviewing monopoly T&D rates. T&D charges have remained structured as they were prior to restructuring, reduced by the removal of the generation portion of the rates, and so they differ by season, TOD, and demand and energy, according to customer class. The PUC is evaluating whether these distinctions make sense in the new environment or whether alternative rate designs would be more appropriate.[55]

2. Puget Sound Energy

Puget Sound Energy is the largest utility in the Pacific Northwest, providing gas and electric service to some 1.2 million consumers in the state of Washington. It was recognized with the Edison Award in 2001 for its "Personal Energy Management" residential TOU rate, but it is less well known for an industrial real-time pricing rate it offered between 1996 and 2001 (described in a following section).

The Personal Energy Management program applies to some 300,000 residential consumers whose residences are fitted with advanced electric meters that can be read via a cellular network operated by Schlumberger. All customers are on a time-of-use rate, but they also have the option to drop off it. The rate is a four-period time-of-use rate, with morning, mid-day, and afternoon "on-peak" rates, and a night, Sunday, and holiday "off-peak" rate. The maximum differential between the on-peak and off-peak rates is $.02/kWh. Evaluation of the program to date has shown that the average consumer has shifted about 14 kWh/month from on-peak to off-peak periods, and at a cost (capital and operations) per consumer of about $2.00 - $3.00 per month.[56] Given an average on-peak, off-peak wholesale price differential in the Pacific Northwest of about $.01/kWh or less, even with the distribution capacity benefits of the program, the program does not yield net benefits from among low-use residential customers. However, for larger commercial and industrial consumers, where greater usage and bigger load shifts might be anticipated with a corresponding difference in metering cost per kWh, the economics can be quite different.

Preliminary analysis of this program suggests that the TOU customers, while shifting load to the off-peak period, are actually using more electricity than the control group.[57] In response to concerns raised by the public related to cost, conservation, and customer acceptance, Puget has agreed that future TOU pricing will be offered on an optional, not mandatory, basis (customers must opt *into*, not *out of*, the rate).[58]

The metering and communication system that underpins the TOU rate is straightforward. The meter is a simple electronic kWh revenue meter. At the end of each rate period –

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[55] Conversation with Faith Huntington, Director of Technical Analysis, Maine Public Utilities Commission, 17 April 2002; Maine PUC website, www.state.me.us/mpuc.

[56] Testimony of Penny Gullickson before the Washington Utilities and Transportation Commission, Docket No. UE-011570.

[57] An Evaluation of the Impacts of Puget Sound Energy's Time-Of-Day Program, Brattle Group, November 5, 2001, P. 6.

[58] Settlement Stipulation in Docket No. UE-011570, Washington Utilities and Transportation Commission, filed March 19, 2002.

that is, every few hours – the meter is polled automatically by a cellular phone system and the amount of kilowatt-hours consumed during the period (computed by subtracting the previous reading from the current one) is forwarded from the cellular antenna (on a pole not far from the meter) via a dedicated network to Puget's billing center.[59] It is an example of the "dumb meter, smart network" approach to AMR.

3. California

In June 2001, at the height of the electricity shortage, the California Public Utilities Commission approved inclining (or inverted) block rates for residential customers of Southern California Edison (SCE) and Pacific Gas & Electric (PG&E). The block prices increase significantly, thus creating a strong incentive to conserve. All residential usage below 130% of baseline is exempt from further rate surcharges as mandated by statute AB 1x. For residential customers who use more than 130% of baseline, each additional kilowatt-hour used will be charged at an increasingly higher rate (the blocks vary by climate zone). The PUC adopted five residential rate tiers that correlate to the amount of electricity used per month. The rate surcharge is paid by the three highest usage tiers, as follows:

Tier 1: up to 100% of baseline	No increase by statute
Tier 2: 100-130% of baseline	No increase by statute
Tier 3: 130-200% of baseline	12% increase or less, depending on usage
Tier 4: 200-300% of baseline	29% increase or less, depending on usage
Tier 5: over 300% of baseline	47% increase or less, depending on usage

This rate design was one component of an overall strategy to reduce energy consumption during last year's crisis. In concert, the programs had the effect of reducing demand by more than twelve percent below the previous year's levels and total energy consumption by more than six percent.[60] This result is consistent with research in the Pacific Northwest on the peak-period orientation of discretionary residential usage.

B. Real Time Pricing and Related Programs in Practice

1. Georgia Power

In 1990, Georgia Power Company (GPC) was granted approval to offer a tariff that it called Real-Time Pricing. It is described as a "two-part" tariff, consisting of an

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[59] In the Schlumberger Cellnet system, the meters are typically polled more frequently than at the end of each rating period, sometimes as often as every five minutes. The cost of doing so is minimal, but the value of the insurance against loss of data is significant. If, at the end of a rating period, the final polling is performed successfully, all interim polling data can be discarded. Communication with Paul Gromer, March, 25, 2002.

[60] California PUC, Decision 01-05-064, May 15, 2001, at 3-4; Synapse Energy Economics, *Survey of Clean Power and Energy Efficiency Programs*, Ozone Transport Commission, January 14, 2002, at 18-21; Natural Resources Defense Council, *Energy Efficiency Leadership in a Crisis: How California is Winning*, August 2001, at 1.

embedded cost rate and a marginal cost rate.[61] The tariff has gone through some redesign since its roll-out. It now serves approximately 1,600 customers with 5,000 MW of load.[62] GPC developed the program in order to be more competitive: under Georgia law, customers with more than 900 kW of connected load are allowed to put their consumption out to bid.

The tariff is fairly straightforward. Under the first part of the tariff, the customer pays the applicable embedded cost rates for a baseline amount of consumption. The customer baseline (CBL) reflects historical levels of consumption, hour by hour. Since both the unchanging CBL and the embedded rate are known, the customer is in effect paying a fixed fee for a set amount of kilowatt-hours per month. Any actual deviations from the CBL load shape are priced at the hourly price for power. This is the second part of the tariff. If the deviation constitutes an increase over the CBL, the customer pays an amount equal to the product of the hourly price and the incremental usage. If the deviation is in fact a decrease, the customer is given a credit equal to the product of the hourly price and the decremental savings. The hourly price is made up of a measure of marginal energy costs, line losses, a "risk recovery factor" (a fixed adder), and, at peaks, marginal transmission costs and outage cost estimates (value of loss of load).[63]

GPC offers two options: a "day-ahead" program, in which customers are notified of price schedules by 4:00 pm the day before they go into effect, and an "hour-ahead" program, in which customers are given an hour's notice on price. For interruptible customers, who are served under the hour-ahead program, the CBL drops to their firm contract level during periods of interruption. Those who do not decrease demand to their firm level when required pay an interruption penalty and the hourly prices. A proposal to allow interruptible customers on the day-ahead rate as well has been filed. The risk recovery factor for the day-ahead rate is greater than that for the hour-ahead rate ($0.004/kWh versus $0.003/kWh), on the ground that the utility bears a greater forecast risk.[64]

At first, GPC based the CBL on an 8,760-point hourly load profile. This was confusing to most customers, however. Now the company offers two approaches. One is a 360-point CBL – 24 average hourly weekday loads per month and six average 4-hour weekend day

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[61] O'Sheasy, Michael T., "How to Buy Low and Sell High," *The Electricity Journal*, January/February 1998, Vol. 11, No. 1., at 24*ff.* Many regulators would regard the tariff as three-part, however, since a fixed daily or monthly customer charge is also included.

[62] Jaske, Michael R., California Energy Commission, testimony regarding rate design matters in California Public Utilities Commission Applications 00-11-038 *et al.*, April 13, 2001, at 4.

[63] Marginal cost was originally defined as the system lambda. However, after the Georgia market opened up, real-time prices increased by approximately one cent/kWh. This led to customer complaints, and hearings before the Commission. The PSC responded by lowering the risk recovery factor and by also requiring that, whenever GPC's load was greater than that supplied by its own generation, hourly prices were to be based on the average price of purchased power, rather than the cost of the marginal block of power. Marginal transmission costs are triggered by load and temperature. Outage costs are based on loss of load probabilities and customer estimates of the costs they face when an outage occurs. Faruqui *et al.* at 27.

[64] *Id.*

loads, for a total of 30 CBL points per month. The second is two-point CBLs – average usage levels for the peak and off-peak periods. Most customers use this latter option.[65]

The two-part nature of the tariff has certain advantages, particularly in terms of risk-sharing. The first part assures that that the utility will continue to receive revenues to cover fixed costs, although it continues to bear some risk that, for the CBL usage, occasionally the marginal cost will exceed the associated revenue. By the same token, the tariff's first part protects the customer from precisely that price risk. The second part of the tariff in effect reverses the risk burdens. The utility is now assured that incremental demand will not occur at rates insufficient to cover the incremental costs it bears, and the customer suddenly has a strong incentive to shift its incremental consumption to low-cost periods or, better yet, reduce consumption altogether during high-cost hours and so receive a credit against its total bill. At times of peak wholesale prices, GPC's RTP customers have reduced their load by over 800 MW (17% of total RTP load).[66]

GPC offers a variety ways for customers to change their exposure to price risk. For customers who have been on RTP for at least a year, there is the adjustable CBL. Given its expectations of marginal costs in a coming period, a customer can either raise or lower its CBL. Roughly 600 customers currently make use of adjustable CBLs. About 60% of the incremental energy sold on RTP rates (that is, usage greater than the baseline) is protected by this product.[67] In addition, GPC offers a number of financial hedging products to limit customers' exposure to RTP volatility: price caps, contracts for differences, collars, index swaps (tying RTP prices to a commodity index), and index caps (tying an RTP price cap to a commodity index). The Company currently has 250 contracts with about 90 customers. Some customers have more than one contract, covering different time periods. GPC does not believe that these price protection products (PPPs) have increased the number of customers on real-time prices, but it has increased customer satisfaction. The utility has found no evidence that the PPPs have decreased price responsiveness.[68]

Georgia Power makes several observations about real-time pricing. First, RTP can produce significant peak savings, even though many customers are not particularly responsive to price. For example, when the hourly price reached $6.40/kWh, customers reduced their demand by 850 MW (interestingly, this was out of approximately 1,500 – 2,000 MW of incremental, or above-CBL, load).[69] Second, the program provides access to low-price off-peak power, which appears to be its primary appeal to customers, many of whom have in fact increased their overall electric consumption.[70] Third, customers' expectations of low-cost power led them to file for relief with the PSC (which they were granted) when the hourly prices rose significantly. Fourth, a wide variety of customers

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[65] *Id*. at 27-28.
[66] Jaske at 5.
[67] Faruqui *et al.* at 28.
[68] *Id*.
[69] *Id*.
[70] *Id*.; O'Sheasy at 25.

will respond to price: chemical and pulp and paper companies, commercial customers, office buildings, universities, grocery stores, and even a hospital (that changes chiller use based on hourly prices). And, lastly, customer education is essential to the success of the program. The customer requires training not only when it begins service under the RTP tariff, but also on-going program review, as the customer sees how the tariff works in practice and as its staff inevitably turns over. GPC holds annual workshops around the state for its RTP customers.[71]

2. Duke Power

In 1993 Duke Power initiated its real-time pricing program with twelve customers. The program was developed to allow load building when capacity is available and load shifting in response to price. By 2000, there were more than 100 commercial and industrial customers in the program. Market prices, however, were high for many hours in that year, and a number of customers dropped out the program and went back to the embedded cost-based TOU rate. By autumn 2001, only 59 customers remained on the rate. Of interest, however, is that total load response in 2001 was approximately equal to that in 2000, because those who dropped off the rate had not responded significantly to price anyway.

Like Georgia Power's rate, Duke's also is a two-part RTP rate. Customers purchase a pre-determined baseline usage on embedded rates. Incremental demand and decremental savings in each hour are purchased or credited at the hourly price. The hourly price consists of hourly energy charges (marginal operating costs adjusted for line losses) and "rationing" charges (adders that reflect reduced transmission reliability from heavy loading and reduced generation reserves). The rationing charge is based on the utility's long-run marginal costs, and is zero in times of no constraints. There is, in addition, an adder of $0.005/kWh (the "incentive" margin), on each kWh of net *incremental* load for the month.[72] The adder is intended to offset some lost revenues resulting from peak-period load reductions. Lastly, there is an incremental demand charge, intended to cover incremental investments in local distribution facilities. It is applied only to the difference between the maximum demand during the month and the billing demand during the corresponding month of the customers pre-set baseline.

Duke originally set the baseline according to the customer's historic 8,760-hour load profile. Now it is based on monthly average usage. Most customers that join the RTP rate had previously been on Duke's TOU rate, and so they have peak and off-peak load profiles for the baseline. The main reason for going to average monthly usage was the significant randomness in the 8,760-hour load profile.

Duke found, unlike some of the other utilities described below, that it can elicit a large demand response out of a small number of customers. Price matters, and customers will

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[71] Faruqui *et al.* at 29.

[72] For example, if a customer used 2,000 kWh above baseline in the off-peak period and 1,000 kWh less than baseline in the on-peak period, the incentive margin would be applied to the 1,000 kWh net increase in usage.

respond to changes in them. In 2000, about 25 of the 100 RTP customers shifted load in response to high prices, and the peak load of all the RTP customers decreased by about 15-20%. Customers who shifted load tended to be those with their own generation, or those able to reschedule production processes (*i.e.*, paper manufacturers with grinders, steel customers with arc furnaces, and universities). Most of the load shifting occurred within a day, but that some shifted from one day to another.[73]

3. Tennessee Valley Authority

TVA began its RTP program, called Economy Surplus Power (ESP), in 1986. It is now one of the country's largest programs, with over 350 customers purchasing hourly-priced energy. The program was designed expressly to sell surplus power during non-constrained, off-peak periods; consequently all ESP sales are interruptible. Interruptibility was key to TVA, which saw the ESP as a load management tool and understood that, whereas some customers would respond to high prices, others would not.

TVA is now replacing the ESP program with a similar one called the Variable Price Interruptible (VPI) program. The VPI rate design is similar to that of the ESP; the main difference is that the ESP hourly price based on the price of the top 100 MW of system supply, whereas the VPI hourly rate is based on the top 1,000 MW of system supply.[74] As a result, the VPI hourly rate is less volatile than that of the ESP. Customers purchasing ESP power will continue to do so until their contract periods end, at which time they can purchase VPI power.

TVA is developing a two-part RTP rate. It too will be interruptible, and the baseline usage will include the customer's firm and interruptible power, with each billed on the appropriate rate schedule.[75] The two-part RTP rate will be open to customers 20 MW and larger.

The interruptibility feature is unique, but otherwise the ESP and VPI rates are typical one-part RTP rates. They include a demand charge that mostly covers transmission costs. The hourly price is based on the marginal cost of supply, with markups for generation capacity, time-variant T&D capacity, and so on. The capacity charges are less than they would be in a firm rate; this is *quid pro quo* for the utility's ability to interrupt.[76]

4. Pacific Gas & Electric

PG&E's RTP program began in 1985 as a pilot with four customers. In the early 90s, it was expanded to (and capped at) fifty customers. A further expansion was under consideration but dropped when restructuring began. In 2001, the program was serving

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[73] Faruqui *et al.* at 25-26.
[74] VPI also enhances the ESP rate by offering more options on curtailment priority. Both ESP and VPI rates are developed for different curtailment groups, with different priorities of interruption, and different notice periods prior to interruption.
[75] Customer response to the two-part has been mixed, apparently because the blending of firm and interruptible power in the baseline has been confusing.
[76] Faruqui *et al.* at 31-32.

about 25 customers, but was closed to new entrants, on the grounds that, in a restructured market, there was no need for RTP based on administratively determined, rather than market, prices.

PG&E uses a one-part RTP rate. In addition, there are a customer charge and a nominal demand charge, designed to recover certain non-time-differentiated customer costs. Most of the customer's costs are in the hourly energy rates. Energy charges are calculated for each hour. The determination begins with a fixed base rate (administratively set) to which a "gas adjustment multiplier" is added when a gas-fueled plant is on the margin. This sum is then multiplied by the revenue reconciliation multiplier. To this product are added increments to cover daily variations in T&D costs and generation capacity costs. The generation capacity adder is called the Load Management Price Signal (LMPS) and is intended to reflect costs at times when there is a high probability of system constraints. The number of hours per year that the LMPS (which can at times exceed $1.00/kWh) can be applied to the energy charge is limited however, to reduce customer price risk.

Prior to restructuring, PG&E concludes, its RTP tariff worked well and customers reduced demand significantly as prices rose. The utility discovered that the program was successful not only with industrial customers but also office buildings, which found ways to manage their loads in response to price.[77]

5. Southern California Edison

Southern California Edison began with an experimental RTP program in 1987. It now has about 100 large power, interruptible, and agricultural customers on real-time pricing (making it one of the larger RTP programs in the US). All take service under a one-part, administratively determined rate, called RTP-2. A two-part rate had been developed in the mid-90s, but was abandoned as restructuring proceeded.

A couple of years ago, SCE introduced tariff RTP-3, which used power exchange-based market prices, adjusted by a T&D capacity adder. The RTP-3 rate exposed customers to very high rates, but, interestingly, many customers did shift load in response. As their bills rose, SCE allowed them to get off the RTP-3 rate, despite their being contractually bound to it. By the time the power exchange was closed, most customers were off the RTP-3 rate, and in January 2001, SCE withdrew the RTP-3 rate altogether.

SCE's RTP is described as a one-part rate program, with demand charges and hourly energy charges. Hourly energy charges are based on marginal energy costs and time-variant capacity costs. Multipliers are applied to the hourly energy rates in order to reconcile revenues. The hourly charges are not, however, linked directly to the wholesale prices. Instead, SCE uses nine day-types,[78] and allocates costs to each hour of each day type. The hourly prices for each day type are pre-set and known to customers. The utility determines the day type in "real-time" based on the maximum temperature in downtown

[77] Faruqui *et al.* at 29-30.
[78] Extremely hot summer weekday, very hot summer weekday, hot summer weekday, moderate summer weekday, mild summer weekday, high and low cost winter weekdays, and high and low cost weekends.

L.A. on the prior day.[79] The interruptible version of the rate is similar, except that it credits generation capacity costs to customers, as does the standard interruptible rate. The energy charges in the peak periods are capped at \$3.00 per kWh; as revenue requirements increased over time, the RTP increases were allocated to the shoulder periods.

SCE believes that the RTP programs should be marketed directly to the customers most likely to shift load. Its experience suggests that a number of time-of-use customers migrated to the RTP program (which was designed to be revenue neutral with the TOU-8 rate) mostly because, given their historic load profiles, the RTP tariff would save them money. In many cases, these customers – in effect, "free riders" – did not respond even when RTP-3 prices became very high. However, they eventually dropped off the rate.[80]

6. BC Hydro

In 1996, British Columbia Hydro began an RTP program that gave industrial customers access to low-cost power from the northwestern US wholesale market (\$0.01-0.015/kWh versus \$0.02-0.025/kWh at retail). At its peak, about 25 customers were in the program. By 1999, however, all had left it, because wholesale prices exceeded the embedded tariff rates. None have joined since then.

The BC Hydro RTP rate is a two-part rate, similar to that of Georgia Power. The first (embedded) portion of the rate is a time-of-use rate (peak period from 6:00 am to 10:00 pm), charged to the customer's baseline demand. The baseline is computed as a function of the customer's three prior years' usage. The real-time component is based on the Dow Jones Mid-Columbia Index. Customers can select either the Mid-Columbia peak and off-peak price, or the mid-point of the next day's prescheduled price range. As such, the program offers day ahead variable pricing, but prices do not vary hourly.

Usage in excess of the baseline is charged at the real-time price. If a customer uses between 75% and 100% of its baseline, the reduction is credited not at the RTP rate but at the embedded rate. Reductions below 75% of the baseline are credited at the RTP rate. In addition, customers are allowed to purchase blocks of power in advance of use, at market prices, to replace a portion of their baseline usage. Customers are credited 80% of the real time price for daily purchases of unused energy. Also, the company offers a load retention rate that gives customers the option to have 50% of their baseline billed at embedded rates and the other 50% at market prices. These non-standard features emerged from negotiations with customers.

BC Hydro found that the primary reason customers joined the program was to save money and that they were not generally willing to adjust usage to increase savings. The customers on the rate were from the major industries in the province: pulp and paper, mining, and electrochemical. Interestingly, there was very little demand response from

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[79] The RTP-3 rate was similarly structured, however only hourly T&D costs were obtained from the menu of day types. The energy and generation capacity components were based on power exchange prices.
[80] Faruqui *et al.* at 30-31.

them—neither load shifting nor load growth. The company found that it was difficult to determine how customers will respond to variable prices. Often, the financial managers favored rescheduling production to achieve savings, whereas the operations people discouraged it.[81]

7. California Energy Commission Proposal

In April 2001, the California Energy Commission filed testimony with the California Public Utilities Commission recommending the adoption of a voluntary real-time pricing program. The essential features of the proposed program are similar to those of Georgia Power, Duke, and BC Hydro. It is a two-part rate in which baseline usage is purchased at embedded rates and incremental consumption or decremental savings are priced or credited at the real-time hourly rate. The hourly charge/credit is calculated as the product of the deviation in measured hourly load from historic load for each hour and the real-time energy price. The real-time price is the California ISO's imbalance energy cost in each hour, net of the base tariff rate for the energy component applicable to that hour. Baseline loads are computed as the monthly average load for each hour in a day (based on usage in the same month in the previous year), differentiated by weekday and weekend.[82]

In order to participate, a customer would need an interval meter (and, for direct access customers, appropriate meter data management arrangements) and would need to have sufficient historic data to support the baseline computations. Also, a customer would have to agree to participate in the program for at least six months.[83]

8. Pacific Northwest

a) Puget RTP

Between 1996 and early 2001, Puget Sound Energy also offered a real-time pricing program for its largest commercial and industrial consumers (those with demand exceeding 2.4 MW). Some eighteen consumers, with a combined demand of approximately 300 MW, participated in the program. The rate consisted of a delivery charge and a market energy charge. There were two components to the energy charge, on-peak (7:00 AM – 10:00 PM) off-peak rate. They were computed daily, based on the Mid-Columbia index published by Dow Jones. For the first four years of this program, the participating consumers saved over $50 million when compared with payments they would have made under the traditional industrial tariff. When, however, the west coast drought triggered an unprecedented rise in wholesale energy prices beginning in May 2000, the program began to unravel. Industrial consumers accustomed to moderate price volatility, with the energy rates ranging from $10 to $40/MWh were suddenly exposed to wholesale prices that went as high as $1,000/MWh. Several industrial installations ceased operations entirely (one paper mill was closed permanently), while others installed

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[81] Faruqui *et al.* at 24-25.
[82] For example, the baseline for hour 1300 on a July weekday is the average of all loads during that hour on July weekdays (excluding holidays). Weekend computations are similar, except that holidays are included.
[83] Jaske at 8-11.

temporary diesel generators to avoid the high market prices. In the fall of 2000, the industrial consumers petitioned the WUTC to modify the program and, in a negotiated settlement, the larger consumers were permitted direct access to the market, while the smaller consumers were returned to tariff rates.[84]

b) Drought Response Programs[85]

The west coast energy crisis of 2000 – 2001 was triggered by a drought in the Pacific Northwest that removed about 4,000 MW of hydroelectric generation from the regional grid, with additional hydro losses in California and British Columbia. It was compounded by high natural gas prices across North America, and by a variety of factors in California, including gas transmission limitations, electric transmission limitations, an inelastic market for pollution emission credits in southern California, and possible market manipulation by major generation owners.

At the peak of the crisis, in December 2000, it became evident that supply-side strategies alone would not solve the crisis. With forward market prices in the range of $200 - $400 per megawatt-hour (ten times historic levels), a number of utilities introduced a variety of programs to bring demand in line with supply.

The single largest program was the Bonneville Power Administration's agreements with aluminum smelters to reduce consumption by approximately 2,600 megawatts. The smelters had contracts to purchase power from Bonneville at a price of less than $40/MWh; Bonneville contracted to pay the smelters about half of the expected market savings in exchange for demand response. It also made a similar offer to irrigators, and secured about 200 MW of irrigation load relief.

The Pacific Northwest investor-owned utilities all implemented so-called demand-exchange programs in December 2000 for large-volume customers. The tariffs approved by the WUTC (at an unprecedented Saturday emergency meeting) permitted bilateral negotiations for load reductions. Customers that reduced load below historic baselines were paid a fixed amount per MWh curtailed (in addition to avoiding the tariff rate for power). The prices paid ranged from $50 to $225/MWh.

A different program structure was implemented for smaller consumers. Pacificorp (and the California IOUs) implemented a so-called "20/20 Plan" in which customers that reduced usage by 20% or more received a 20% discount on their bills (in addition to the direct savings from the reductions). Puget and Avista implemented "all-customer buy-back" programs that paid consumers $.05/kWh for any savings in excess of a minimum (5% for Avista; 10% for Puget) reduction from previous-year usage. Approximately 30-40% of customers received such credits for one or more months of the period in 2001 when these were in effect.

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[84] Interestingly, Puget twice offered all 18 customers a five-year RTP price hedging option. The first, in 1997, was at $20/MWh, and the second, in 1999, was at $28/mwh. None of the customers took the hedge.
[85] See also Goldman, Charles, *Framing Paper #1: Price-Responsive Load Programs*, NEDRI, March 25, 2002, at 14 and 19.

Finally, the California PUC responded in June 2001 with rate increases and significant changes in rate design (see section III.A.3., above). Overall rates increased approximately 40% for the California utilities. For larger, time-of-use customers, the vast majority of this increase was imposed on usage during the on-peak period. For residential consumers, the entire increase was imposed on usage levels above the "conservation baseline" allocation, with rates for usage in excess of 200% of baseline (*i.e.*, the price-sensitive space conditioning load) set as high as two-times the previous rates. The result of these rate changes, plus moral suasion, the 20/20 plan, and other measures, was a roughly 5,000 MW reduction in peak demand in the state.

Because this crisis was drought-induced (reducing energy availability) in a capacity-rich region, the lessons may require adaptation for use in regions dominated by thermal generation, where capacity limitations exist. It is clear, however, that price stimuli can work in fairly short periods of time to achieve significant levels of demand reduction from a variety of types of consumers.

9. Central Vermont Public Service

Central Vermont Public Service does not have a real-time pricing program, although it does have one customer taking service at hourly rates. That customer, a ski resort, has for more than a decade been served under an interruptible contract that allows it to purchase energy in excess of a pre-set firm amount. This "supplemental energy" (used primarily for snow-making) does not incur demand charges, so long as the customer interrupts service when so instructed by the utility (*i.e.*, when the customer's load will cause additional capacity charges to be incurred by the utility). Historically, the supplemental energy charge was fixed at a rate reflecting the company's average marginal energy cost, marked up to cover additional delivery charges. However, with the restructuring of the New England wholesale market in the late 90s, it occasionally happened that the market price for energy exceeded the fixed rate, and the utility called for interruptions. To reduce the number of these "economic" interruptions, CVPS and customer developed a pricing plan that charges the customer the hourly price for energy (as cleared in the day-ahead market, marked up for any delivery and overhead costs). If the hourly price exceeds a specified amount ($0.15/kWh), supplemental service will not be scheduled for those hours. The customer has been quite satisfied with this change in the contract.[86]

CVPS has a number of interruptible contracts with ski areas and C&I customers, some of which make use of some form of market-based pricing. The company has learned that commercial and industrial customers are, for the most part, reluctant to go to real-time pricing. They prefer the "security blanket of tariffed rates," which lack the volatility of RTP. Customers are unlikely to become "price junkies." The company believes that increased penetration of real-time pricing will depend upon the availability of "cheap, reliable communications." In several instances, the company notifies the customer of when to interrupt via a paging system. The message gives the customer two hours' notice

[86] Conversation with William Deehan, Vice President of CVPS, March 19, 2002.

of when the price is expected to exceed an agreed-on threshold. Many of its larger customers have interval meters whose data can be accessed by a PC through a serial port, thus giving the customers the ability to monitor their own loads. For the most part, the meters are not linked in real-time to the utility, but in several cases the meters are accessible via cell phone.[87]

10. Gulf Power

In Florida, Gulf Power offers the Advanced Energy Management *Good Cents Select* (AEM) program. It enables customers to control their energy usage by programming their cooling and heating systems, water heating, and pool pumps to automatically respond to varying prices. Customers program their end-uses to operate or not, depending on the price of power at particular times of the day. To participate, customers must take service under the Residential Variable Service Program rate (RVSP), a form of time-of use pricing that has a real-time component to it. There are four daily rating periods and rates: Low, Medium, High, and Critical. For the Low, Medium, and High rating periods, both the times and rates are set by tariff.[88] For the Critical period, only the rate is set; the times at which it occurs depend upon circumstances in the wholesale market. This is the real-time feature of the tariff. The rates are as follows:

Standard customer charge:	$8.07/month
RVSP participation charge:	$4.53/month (optional, for participants only)
Energy charges	
Low	$0.035/kWh
Medium	$0.046/kWh
High	$0.093/kWh
Critical	$0.29/kWh

The standard tariff has the customer charge of $8.07/month and a flat energy rate of $0.057/kWh.

The AEM program requires a "Superstat," a small electronic module that is used to program the operations of the end-uses. A module, called a communications "gateway," is also added to the meter. It enables communication between the utility and the Superstat (alerting it of critical periods) and among the system components (to interrupt demand), and it records energy usage for transmittal to the utility. The utility communicates with the gateway through use of a paging signal. Billing information is later retrieved via the land-line public switched telephone network (in the middle of the night). Signals are passed from the gateway to the controlled end-uses over the house's internal wiring and, to and from the Superstat, over the existing thermostat wiring. Diversified summer load reductions have averaged 2.10 kW per house in the summer and 2.73 kW/house in the winter. Average annual bills without AEM are $1254, and $1,067 with AEM, an approximately 14% savings.[89] 27% of the time the price is low. It is

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[87] *Id.*
[88] The hours of the high and medium periods differ seasonally (winter and summer).
[89] www.southerncompany.com/goodcents. Also telephone communication with a Gulf Power customer representative, March 26, 2002.

medium 53% of the time and high 19%. The price has gone "critical" only 1% of the time. Critical periods are most likely to occur Monday-Friday between 6:00 am and 10:00 am in the winter and between 3:00 pm and 6:00 pm in the summer.

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